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

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 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 No. 1-11680

GulfTerra Energy Partners, L.P.

(Exact Name of Registrant as Specified in its Charter)

Delaware	**76-0396023**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
4 Greenway Plaza Houston, Texas	**77046**
(Address of Principal Executive Offices)	(Zip Code)

Registrant's Telephone Number, Including Area Code: **(832) 676-4853**

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 ☑ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☑ No ☐

The registrant had 59,685,667 common units outstanding as of May 3, 2004.

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit amounts)
(Unaudited)

	Quarter Ended March 31,	
	2004	2003(1)
Operating revenues	$220,339	$230,095
Operating expenses		
Cost of natural gas and other products	64,427	90,753
Operation and maintenance	48,496	40,644
Depreciation, depletion and amortization	26,223	23,697
Gain on sale of long-lived assets	(24)	(106)
	139,122	154,988
Operating income	81,217	75,107
Earnings from unconsolidated affiliates	2,208	3,316
Minority interest income (expense)	12	(33)
Other income	160	383
Interest and debt expense	28,031	34,486
Loss due to write-off of unamortized debt issuance costs	—	3,762
Income before cumulative effect of accounting change	55,566	40,525
Cumulative effect of accounting change	—	1,690
Net income	$ 55,566	$ 42,215
Income allocation		
Series B unitholders	$ —	$ 3,876
General partner		
Income before cumulative effect of accounting change	$ 21,129	$ 14,860
Cumulative effect of accounting change	—	17
	$ 21,129	$ 14,877
Common unitholders		
Income before cumulative effect of accounting change	$ 29,065	$ 17,454
Cumulative effect of accounting change	—	1,340
	$ 29,065	$ 18,794
Series C unitholders		
Income before cumulative effect of accounting change	$ 5,372	$ 4,335
Cumulative effect of accounting change	—	333
	$ 5,372	$ 4,668
Basic and diluted earnings per common unit		
Income before cumulative effect of accounting change	$ 0.49	$ 0.40
Cumulative effect of accounting change	—	0.03
Net income	$ 0.49	$ 0.43
Basic weighted average number of common units outstanding	58,946	44,020
Diluted weighted average number of common units outstanding	59,242	44,104
Distributions declared per common unit	$ 0.710	$ 0.675

(1) See Note 1, Basis of Presentation and Summary of Significant Accounting Policies; Revenue Recognition and Cost of Natural Gas and Other Products.

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except unit amounts)
(Unaudited)

	March 31, 2004	December 31, 2003
ASSETS		
Current assets		
Cash and cash equivalents	$ 23,257	$ 30,425
Accounts receivable, net	166,432	154,235
Affiliated note receivable	3,713	3,768
Other current assets	23,525	20,595
Total current assets	216,927	209,023
Property, plant, and equipment, net	2,916,484	2,894,492
Intangible assets	3,309	3,401
Investments in unconsolidated affiliates	190,732	175,747
Other noncurrent assets	36,564	38,917
Total assets	$3,364,016	$3,321,580
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable	$ 139,857	$ 168,133
Accrued interest	33,982	11,199
Current maturities of senior secured term loan	3,000	3,000
Other current liabilities	40,702	27,035
Total current liabilities	217,541	209,367
Revolving credit facility	387,000	382,000
Senior secured term loan, less current maturities	297,000	297,000
Long-term debt	1,137,161	1,129,807
Other noncurrent liabilities	41,596	49,043
Total liabilities	2,080,298	2,067,217
Commitments and contingencies		
Minority interest	1,801	1,777
Partners' capital		
Limited partners		
Common units; 59,685,667 and 58,404,649 units issued and outstanding	930,340	898,072
Series C units; 10,937,500 units issued and outstanding	338,297	341,350
General partner	13,280	13,164
Total partners' capital	1,281,917	1,252,586
Total liabilities and partners' capital	$3,364,016	$3,321,580

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Quarter Ended March 31, 2004	Quarter Ended March 31, 2003
Cash flows from operating activities		
Net income	$ 55,566	$ 42,215
Less cumulative effect of accounting change	—	1,690
Income before cumulative effect of accounting change	55,566	40,525
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	26,223	23,697
Distributed earnings of unconsolidated affiliates		
Earnings from unconsolidated affiliates	(2,208)	(3,316)
Distributions from unconsolidated affiliates	750	4,710
Gain on sale of long-lived assets	(24)	(106)
Loss due to write-off of unamortized debt issuance costs	—	3,762
Amortization of debt issuance costs	1,358	2,092
Other noncash items	3,036	523
Working capital changes, net of acquisitions and noncash transactions	(21,241)	(443)
Net cash provided by operating activities	63,460	71,444
Cash flows from investing activities		
Additions to property, plant and equipment	(47,833)	(81,937)
Proceeds from sale and retirement of assets	93	3,088
Additions to investments in unconsolidated affiliates	(5,800)	(133)
Net cash used in investing activities	(53,540)	(78,982)
Cash flows from financing activities		
Net proceeds from revolving credit facility	44,933	98,991
Repayments of revolving credit facility	(40,000)	(119,000)
Repayment of senior secured acquisition term loan	—	(237,500)
Debt issuance costs for senior secured term loan	(57)	—
Net proceeds from (debt issuance costs for) issuance of long-term debt	(30)	293,277
Net proceeds from conversion of Series F units	48,274	—
Distributions to partners	(70,529)	(52,080)
Contribution from general partner	321	—
Net cash used in financing activities	(17,088)	(16,312)
Decrease in cash and cash equivalents	(7,168)	(23,850)
Cash and cash equivalents at beginning of period	30,425	36,099
Cash and cash equivalents at end of period	$ 23,257	$ 12,249

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE LOSS
(In thousands)
(Unaudited)

Comprehensive Income

	Quarter Ended March 31, 2004	Quarter Ended March 31, 2003
Net income	$55,566	$42,215
Other comprehensive loss	(4,299)	(5,715)
Total comprehensive income	$51,267	$36,500

Accumulated Other Comprehensive Loss

	March 31, 2004	December 31, 2003
Beginning balance	$ (9,027)	$ (5,622)
Unrealized mark-to-market losses on cash flow hedges arising during period	(8,092)	(12,924)
Reclassification adjustments for changes in initial value of derivative instruments to settlement date	3,793	10,018
Accumulated other comprehensive loss from investment in unconsolidated affiliate	—	(499)
Ending balance	$(13,326)	$ (9,027)
Accumulated other comprehensive loss allocated to:		
Common units' interest	$(11,085)	$ (7,488)
Series C units' interest	$ (2,068)	$ (1,409)
General partner's interests	$ (173)	$ (130)

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

We are a publicly held Delaware master limited partnership (MLP) established in 1993 for the purpose of providing midstream energy services, including gathering, transportation, fractionation, storage and other related activities for producers of natural gas and oil, onshore and offshore in the Gulf of Mexico. Our sole general partner is GulfTerra Energy Company, L.L.C., a recently-formed Delaware limited liability company that is owned 50 percent by a subsidiary of El Paso Corporation and 50 percent by a subsidiary of Enterprise Products Partners L.P. (Enterprise), a publicly traded MLP.

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC). Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles. You should read it along with our 2003 Annual Report on Form 10-K, as amended, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of March 31, 2004, and for the quarters ended March 31, 2004 and 2003, are unaudited. We derived the balance sheet as of December 31, 2003, from the audited balance sheet filed in our 2003 Annual Report on Form 10-K, as amended. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature, to fairly present our interim period results. Information for interim periods may not depict the results of operations for the entire year. In addition, prior period information presented in these financial statements includes reclassifications which were made to conform to the current period presentation. These reclassifications have no effect on our previously reported net income or partners' capital.

With respect to our Texas intrastate pipeline system, which we acquired in April 2002, we had previously used the pre-acquisition accounting methodology for the cash settlement of natural gas imbalance receivables, which included the cash settlement amounts as a component of operating revenues and cost of natural gas and other products. However, effective January 1, 2004, we have conformed our accounting for cash settlements on that system to the same method we use to account for imbalance receivable settlements on our other systems, which method accounts for these types of cash settlements as an adjustment to cost of natural gas and other products. We have determined that this revision is not material to our previously reported financial statements. Accordingly, we have not revised our previously filed financial statements to reflect this change in methodology.

Unbilled Trade Receivables and Accrued Gas Purchase Costs

As of March 31, 2004 and December 31, 2003, we had included in accounts receivable, net on our balance sheets, unbilled trade receivables of $73.3 million and $63.1 million. Also, as of March 31, 2004 and December 31, 2003, we had included in accounts payable on our balance sheets, accrued gas purchase costs of $16.9 million and $15.4 million.

Allowance for Doubtful Accounts

We have established an allowance for losses on accounts that we believe are uncollectible. We review collectibility regularly and adjust the allowance as necessary, primarily under the specific identification method. As of March 31, 2004 and December 31, 2003, our allowance was $4.0 million.

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

/d	= per day	MBbls	= thousand barrels
Bbl	= barrel	MDth	= thousand dekatherms
Bcf	= billion cubic feet	MMcf	= million cubic feet

When we refer to cubic feet measurements, all measurements are at 14.73 pounds per square inch.

Revenue Recognition and Cost of Natural Gas and Other Products

Typhoon Oil Pipeline, a wholly owned subsidiary, has transportation agreements with BHP and ChevronTexaco which provide that Typhoon Oil purchase the oil produced at the inlet of its pipeline for an index price less an amount that compensates Typhoon Oil for transportation services. At the outlet of its pipeline, Typhoon Oil resells this oil back to these producers at the same index price. As disclosed in our 2003 Annual Report on Form 10-K, as amended, we now record revenue from these buy/sell transactions upon delivery of the oil based on the net amount billed to the producers. For the quarter ended March 31, 2003, we reduced by $48.8 million our revenues and cost of natural gas and other products to conform to the current period presentation. This revision had no effect on operating income, net income or partners' capital.

Accounting for Stock-Based Compensation

We use the intrinsic value method established in Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*, to value unit options issued to individuals who are on our general partner's current board of directors and for those grants made prior to El Paso Corporation's acquisition of our general partner in August 1998 under our Omnibus Plan and Director Plan. For the quarters ending March 31, 2004 and 2003, the cost of this stock-based compensation had no impact on our net income, as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. We use the provisions of Statement of Financial Accounting Standards (SFAS) No. 123, *Accounting for Stock-Based Compensation*, to account for all of our other stock-based compensation programs.

If compensation expense had been determined by applying the fair value method in SFAS No. 123 to all of our grants, our net income allocated to common unitholders and net income per common unit would have approximated the pro forma amounts below:

	Quarter Ended March 31,	
	2004	2003
	(In thousands, except per unit amounts)	
Net income as reported[(1)]	$55,566	$42,215
Less: Additional stock-based employee compensation expense determined under fair value based method	(7)	(191)
Pro forma net income	$55,559	$42,024
Pro forma net income allocated to common unitholders	$29,058	$18,603
Earnings per common unit:		
Basic, as reported	$ 0.49	$ 0.43
Basic, pro forma	$ 0.49	$ 0.42
Diluted, as reported	$ 0.49	$ 0.43
Diluted, pro forma	$ 0.49	$ 0.42

(1) Stock-based employee compensation expense of $134 thousand and $313 thousand are included in net income for the quarters ended March 31, 2004 and March 31, 2003.

The effects of applying SFAS No. 123 in this pro forma disclosure may not be indicative of future amounts.

Our remaining accounting policies are consistent with those discussed in our 2003 Annual Report on Form 10-K, as amended, except as discussed below.

Consolidation of Variable Interest Entities

During the first quarter of 2004, we adopted the provisions of Financial Accounting Standards Board Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin (ARB) No. 51*, as replaced by FIN No. 46-R. This interpretation defines a variable interest entity (VIE) as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity and excludes certain joint ventures of other entities that meet the characteristics of a business. Our adoption of FIN No. 46 had no effect on our reported results or financial position.

2. MERGER WITH ENTERPRISE

On December 15, 2003, we, along with Enterprise and El Paso Corporation, announced that we had executed definitive agreements to merge Enterprise and GulfTerra to form one of the largest publicly traded MLPs.

In April 2004, Enterprise and El Paso Corporation amended their agreement with respect to the ownership of Enterprise's general partner interest upon the completion of our merger with Enterprise.

As originally envisioned in the merger agreement, El Paso Corporation was to contribute its 50-percent ownership interest in our general partner to Enterprise's general partner, in exchange for a 50-percent ownership interest in Enterprise's general partner. Under the amended transaction, El Paso Corporation will still contribute its 50-percent ownership interest in our general partner to Enterprise's general partner, but in exchange, El Paso Corporation will receive a 9.9-percent ownership interest in Enterprise's general partner and

$370 million in cash. The remaining 90.1-percent ownership interest in Enterprise's general partner will continue to be owned by affiliates of privately-held Enterprise Products Company.

The remaining transactions with respect to our merger with Enterprise are unchanged. These include:

- the payment of $500 million in cash from Enterprise to El Paso Corporation for approximately 13.8 million units, which include 2.9 million of our common units and all of our Series C units owned by El Paso Corporation;
- the exchange of 1.81 Enterprise common units for each GulfTerra common unit owned by GulfTerra's unitholders, including the remaining approximately 7.5 million GulfTerra common units owned by El Paso Corporation.

Merger Related Costs

As a result of the pending merger with Enterprise, we determined that it was in our and our unitholders' best interest to offer selected employees of El Paso Corporation incentives to continue to focus on the business of the partnership during the merger process. We have accounted for these incentives under the provisions of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* As of March 31, 2004, we recorded a liability and a related deferred charge of $4.3 million, which are reflected in other current liabilities and other current assets on our balance sheets. Our liability was estimated based upon the number of employees accepting the offer and the discounted amount they are expected to be paid. We are amortizing the deferred asset to expense ratably over the expected period of the services required in order to qualify for receiving the payments. We expect to amortize the entire expense by merger close. During the quarter ended March 31, 2004, we had amortized $0.6 million to expense. If our expectations of future amounts to be paid or the period of service to be rendered change, we will adjust our liability.

Additionally, during the first quarter of 2004, we recognized an expense of $3.5 million associated with a fairness opinion we received on our pending merger with Enterprise. All of our merger related costs are included in operation and maintenance expenses on our statements of income and are allocated across all of our operating segments.

3. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

We hold investments in various affiliates which we account for using the equity method of accounting. Summarized financial information for these investments are as follows:

Quarter Ended March 31, 2004
(In thousands)

	Coyote	Deepwater Gateway(1)	Cameron Highway(1)	Poseidon	Total
End of period ownership interest	50%	50%	50%	36%	
Operating results data:					
Operating revenues	$1,800	$ —	$ —	$ 9,275	
Other income	1	5	32	13	
Operating expenses	(198)	(26)	—	(1,336)	
Depreciation	(360)	—	—	(2,109)	
Other expenses	(171)	(214)	(127)	(881)	
Net income	$1,072	$(235)	$ (95)	$ 4,962	
Our share:					
Allocated income (loss)	$ 536	$(118)	$ (48)	$ 1,786	
Adjustments(2)	(2)	32	(9)	61	
Earnings (loss) from unconsolidated affiliates	$ 534	$ (86)	$ (57)	$ 1,847	$2,208(3)
Allocated distributions	$ 750	$ —	$ —	$ —	$ 750

Quarter Ended March 31, 2003
(In thousands)

	Coyote	Deepwater Gateway[1]	Poseidon	Total
End of period ownership interest	50%	50%	36%	
Operating results data:				
Operating revenues	$1,923	$—	$12,062	
Other income	2	13	21	
Operating expenses	(121)	—	(771)	
Depreciation	(339)	—	(2,084)	
Other expenses	(197)	(5)	(1,475)	
Net income	$1,268	$ 8	$ 7,753	
Our share:				
Allocated income	$ 634	$ 4	$ 2,791	
Adjustments[2]	(5)	(4)	(104)	
Earnings from unconsolidated affiliate	$ 629	$—	$ 2,687	$3,316
Allocated distributions	$ 750	$—	$ 3,960	$4,710

(1) Cameron Highway Oil Pipeline Company and Deepwater Gateway, L.L.C. are development stage companies; therefore there are no operating revenues or operating expenses. Since their formations in June 2003 and June 2002, they have incurred organizational expenses and received interest income.

(2) We recorded adjustments primarily for differences from estimated earnings reported in our Quarterly Report on Form 10-Q and actual earnings reported in the unaudited financial statements of our unconsolidated affiliates.

(3) Total earnings from unconsolidated affiliates includes a $30 thousand reduction associated with the true-up of the gain on the sale of our interest in Copper Eagle.

4. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

	March 31, 2004	December 31, 2003
	(In thousands)	
Property, plant and equipment, at cost[1]		
Pipelines	$2,487,102	$2,487,102
Platforms and facilities	121,105	121,105
Processing plants	305,904	305,904
Oil and natural gas properties	131,100	131,100
Storage facilities	337,927	337,535
Construction work-in-progress	431,258	383,640
	3,814,396	3,766,386
Less accumulated depreciation, depletion and amortization	897,912	871,894
Total property, plant and equipment, net	$2,916,484	$2,894,492

(1) Includes leasehold acquisition costs with an unamortized balance of $2.4 million and $3.2 million at March 31, 2004 and December 31, 2003. One interpretation being considered relative to SFAS No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Intangible Assets,* is that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties, as intangible assets on our consolidated balance sheets. We will continue to include these costs in property, plant, and equipment until definitive guidance is provided.

5. FINANCING TRANSACTIONS

The close of the merger with Enterprise, announced in December 2003, will constitute a change of control, and thus a default, under our credit facility, therefore we will either repay or amend the facility prior to the close. In addition, the merger close will constitute a change of control under our indentures, and we will be required to offer to repurchase our outstanding senior subordinated notes (and possibly our senior notes) at 101 percent of their principal amount after the close. In coordination with Enterprise, we are evaluating alternative financing plans in preparation for the close of the merger. We and Enterprise can agree on the date of the merger close after the receipt of all necessary approvals. We do not intend to close until appropriate financing is in place.

Credit Facility

Our credit facility consists of two parts: the revolving credit facility maturing in 2006 and a senior secured term loan maturing in 2008. Our credit facility is guaranteed by us and all of our subsidiaries, except for our unrestricted subsidiaries, as detailed in Note 12, and is collateralized with substantially all of our assets (excluding the assets of our unrestricted subsidiaries). The interest rates we are charged on our credit facility are determined at our option using one of two indices that include (i) a variable base rate (equal to the greater of the prime rate as determined by JPMorgan Chase Bank or the federal funds rate plus 0.5%); or (ii) LIBOR. The interest rate we are charged is contingent upon our leverage ratio, as defined in our credit facility, and credit ratings we are assigned by S&P or Moody's. Depending on the credit ratings on our senior secured credit facility and our leverage ratio, the interest we are charged varies from 1.00% to 2.75% over LIBOR or 0.00% to 1.75% over the variable base rate discussed above. Additionally, we pay commitment fees on the unused portion of our revolving credit facility at rates that vary from 0.30% to 0.50%.

Our credit facility contains covenants that include restrictions on our and our subsidiaries' ability to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies and amend some of our contracts, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries and could restrict our ability to make distributions to our unitholders. In addition, our failure to comply with the provisions of any of the covenants could also be a breach of our merger agreement with Enterprise.

Revolving Credit Facility

At March 31, 2004, we had $387 million outstanding under our revolving credit facility at an average interest rate of 3.11%. We may elect that all or a portion of the revolving credit facility bear interest at either the variable rate described above increased by 1.0% or LIBOR increased by 2.0%. The amount available to us at March 31, 2004, under this facility was $313 million.

Senior Secured Term Loan

At March 31, 2004, we had $300 million outstanding under our senior secured term loan with an average interest rate of 3.36%. The senior secured term loan is payable in semi-annual installments of $1.5 million in June and December of each year for the first nine installments and the remaining balance at maturity in December 2008. We may elect that all or a portion of the senior secured term loan bear interest at either 1.25% over the variable base rate discussed above, or LIBOR increased by 2.25%.

Long-Term Debt

In March 2004, we gave notice to exercise our right, under the terms of our senior subordinated notes' indentures, to repay, at a premium, approximately \$39.1 million in principal amount of our $8^{1}/_{2}$% senior subordinated notes due June 2010. We will recognize additional costs totaling \$4.1 million resulting from the payment of the redemption premiums and the write-off of unamortized debt issuance costs. We will account for these costs as an expense during the second quarter of 2004 in accordance with the provisions of SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.*

In April 2004, we initiated a full redemption of all our outstanding \$175 million aggregate principal amount of $10^{3}/_{8}$% senior subordinated notes due 2009. The notes will be redeemed on June 1, 2004, at a redemption price of 105.2% of the principal amount, plus accrued and unpaid interest to June 1, 2004. Interest on the notes will cease to accrue on and after June 1, 2004, and the only remaining right of holders of the notes will be to receive payment of the redemption price upon surrender to the paying agent, plus accrued and unpaid interest up to, but not including, June 1, 2004. In connection with the redemption of the notes, we will recognize additional expense during the second quarter of 2004 totaling \$12.1 million resulting from the payment of the redemption premium and the write-off of unamortized debt issuance costs.

Our senior and senior subordinated notes include provisions that, among other things, restrict our ability and the ability of our subsidiaries (excluding our unrestricted subsidiaries) to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies, and enter into sale and lease-back transactions, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries in addition to restricting our ability to make distributions to our unitholders. In addition, our failure to comply with the provisions of any of the covenants could also be a breach of our merger agreement with Enterprise. Many restrictive covenants associated with our senior notes will effectively be removed following a period of 90 consecutive days during which they are rated Baa3 or higher by Moody's or BBB— or higher by S&P, and some of the more restrictive covenants associated with some (but not all) of our senior subordinated notes will be suspended should they be similarly rated.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on \$250 million of our $8^{1}/_{2}$% senior subordinated notes due 2011. With this swap agreement, we paid the counterparty a LIBOR based interest rate plus a spread of 4.20% and received a fixed rate of $8^{1}/_{2}$%. The net amount to be paid or received under the interest rate swap contract is added to or deducted from the interest and debt expense on our senior subordinated notes for which the swap contract was executed, payable semi-annually in June and December. In December 2003, we received \$2.8 million related to the interest rate swap contract. We accounted for this derivative as a fair value hedge under SFAS No. 133. In March 2004, we terminated our fixed to floating interest rate swap with our counterparty. The value of the transaction at termination was zero, and as such neither we, nor our counterparty, were required to make any additional payments. Also, neither we, nor our counterparty, have any future obligations under this transaction.

Industrial Revenue Bonds

In April 2004, we reduced the sales tax assessable by the State of Mississippi related to our Petal natural gas storage expansion and pipeline project completed in September 2002, by completing that project's qualification for tax incentives available under the Mississippi Business Finance Act (MBFA). To complete the qualification, Petal Gas Storage, L.L.C. (Petal), our indirect, wholly-owned subsidiary, 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 \$52.0 million in Industrial Development Revenue Bonds to us. The loan agreement and the Industrial Development Revenue Bonds have identical interest rates of 6.25% and maturities of fifteen years. The bonds and tax exemptions are authorized under the

MBFA. 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.

Other Credit Facilities

Poseidon

Poseidon Oil Pipeline Company, L.L.C., an unconsolidated affiliate in which we have a 36 percent joint venture ownership interest, was party to a $185 million credit agreement, under which it had $123 million outstanding at December 31, 2003. In January 2004, Poseidon amended its credit agreement and decreased the availability to $170 million. The amended facility matures in January 2008. The outstanding balance from the previous facility was transferred to the new facility. The interest rates Poseidon is charged on balances outstanding under its 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 March 31, 2004, Poseidon had $119 million outstanding with an average interest rate of 2.60%.

Poseidon's credit agreement contains covenants such as restrictions on debt levels, restrictions on liens, restrictions on mergers and on the sales of assets and dividend restrictions and requirements to maintain certain financial ratios.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on $75 million of the $123 million outstanding at 3.49% through January 2004. This interest rate swap expired on January 9, 2004.

Deepwater Gateway

Deepwater Gateway, our joint venture that is constructing the Marco Polo tension leg platform (TLP), obtained a $155 million project finance loan from a group of commercial lenders to finance a substantial portion of the cost to construct the Marco Polo TLP and related facilities. 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 project finance loan, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of March 31, 2004, Deepwater Gateway had $155 million outstanding under the project finance loan at an average interest rate of 2.88% and had not paid us or any of our subsidiaries any distributions.

This project finance loan will mature in July 2004 unless construction is completed before that time and Deepwater Gateway meets other specified conditions, in which case the project finance loan will convert into a term loan with a final maturity date of July 2009.

Cameron Highway

Cameron Highway Oil Pipeline Company, an unconsolidated affiliate in which we have a 50 percent joint venture ownership interest, entered into a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes, each of which fund proportionately as construction costs are incurred.

The construction loan bears interest at a variable rate. Upon completion of the construction, the construction loan will convert to a term loan maturing 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 $8.125 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by December 31, 2006, the construction loan and senior secured notes become fully due and payable. At March 31, 2004, Cameron Highway has $109 million outstanding under the construction loan at an average interest rate of 4.18%.

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 March 31, 2004, Cameron Highway has $89 million outstanding under the notes at an average interest rate of 7.29%.

The project loan facility as a whole is secured by (1) substantially all of Cameron Highway's assets, including, upon conversion, 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.

Debt Maturity Table

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 are as follows at March 31, 2004 (in thousands):

2004	$ 3,000
2005	3,000
2006	390,000
2007	3,000
2008	288,000
Thereafter	1,135,600
Total long-term debt and other financing obligations, including current maturities	$1,822,600

6. PARTNERS' CAPITAL

Cash distributions

In February 2004, we paid cash distributions of $0.71 per common and Series C unit, representing $49.3 million in aggregate. In addition, we paid our general partner $21.3 million related to its general partner interest. In April 2004, we declared a cash distribution of $0.71 per common unit for the quarter ended March 31, 2004, which we will pay on May 14, 2004, to holders of record as of April 30, 2004. Also in May 2004, we will pay our general partner $21.2 million in incentive distributions. At the current distribution rate, our general partner receives approximately 30.2 percent of our total cash distributions for its role as our general partner.

Series F Convertible Units

In connection with a public offering in May 2003, we issued 80 Series F convertible units convertible into a maximum of 8,329,679 common units and comprised of two separate detachable units. The Series F1 units are convertible into up to $80 million of common units anytime after August 12, 2003, and until the date we merge with Enterprise (subject to other defined extension rights). The Series F2 units are convertible into up to $40 million of common units prior to March 30, 2005 (subject to defined extension rights). The price at which the Series F convertible units may be converted to common units is equal to the lesser (i) of the prevailing price (as defined below), if the prevailing price is equal to or greater than $35.75, or (ii) the prevailing price minus the product of 50 percent of the positive difference, if any, of $35.75 minus the prevailing price. The prevailing price is equal to the lesser of (i) the average closing price of our common units for the 60 business days ending on and including the fourth business day prior to our receiving notice from the holder of the Series F convertible units of their intent to convert them into common units, (ii) the average closing price of our common units for the first seven business days of the 60 day period included in (i); or (iii) the average closing price of our common units for the last seven business days of the 60 day period included in (i). The price at which the Series F convertible units could have been converted to common units, assuming we had received a conversion notice on March 31, 2004 and May 3, 2004, was $41.12 and $39.01 per common unit. Holders of Series F convertible units are not entitled to vote or to receive distributions. The value of the Series F convertible units was $2.6 million as of March 31, 2004, and is included in partners' capital as a component of common units.

In August 2003, we amended the terms of the Series F convertible units to permit the holder to elect a "cashless" exercise — that is, an exercise where the holder gives up common units with a value equal to the exercise price rather than paying the exercise price in cash. If the holder so elects, we have the option to settle the net position by issuing common units or, if the settlement price per unit is above $26 per unit, paying the holder an amount of cash equal to the market price of the net number of units. These amendments had no effect on the classification of the Series F convertible units on the balance sheet at March 31, 2004 and December 31, 2003.

In the first quarter of 2004, 45 Series F1 convertible units were converted into 1,146,418 common units, for which the holder of the convertible units paid us $45 million. Additionally, our general partner contributed to us $0.3 million in cash in order to maintain its one percent general partner interest.

Any Series F1 convertible units for which a conversion notice has not been delivered prior to the merger closing date, or termination of the merger, will expire upon the closing, or termination, of the merger with Enterprise. Any Series F2 convertible units outstanding at the merger date will be converted into rights to receive Enterprise common units, subject to the restrictions governing the Series F units. The number of Enterprise common units and the price per unit at conversion will be adjusted based on the 1.81 exchange ratio.

Option Plans

Total unamortized deferred compensation as of March 31, 2004 and December 31, 2003, was approximately $1.1 million and $1.5 million. Deferred compensation is reflected as a reduction of partners' capital and is allocated 1 percent to our general partner and 99 percent to our limited partners. We did not grant any unit options or restricted units under the Omnibus Plan or the Director Plan during the quarter ended March 31, 2004.

Net proceeds from unit options exercised during the quarter ended March 31, 2004, was approximately $4.6 million. There were no unit options exercised during the quarter ended March 31, 2003.

7. EARNINGS PER COMMON UNIT

The following table sets forth the computation of basic and diluted earnings per common unit (in thousands, except per unit amounts):

	Quarter Ended March 31,	
	2004	2003
Numerator:		
Numerator for basic earnings per common unit —		
Income before cumulative effect of accounting change	$29,065	$17,454
Cumulative effect of accounting change	—	1,340
	$29,065	$18,794
Denominator:		
Denominator for basic earnings per common unit — weighted-average common units	58,946	44,020
Effect of dilutive securities:		
Unit options	275	74
Restricted units	21	10
Denominator for diluted earnings per common unit — adjusted for weighted-average common units	59,242	44,104
Basic and diluted earnings per common unit		
Income before cumulative effect of accounting change	$ 0.49	$ 0.40
Cumulative effect of accounting change	—	0.03
	$ 0.49	$ 0.43

8. RELATED PARTY TRANSACTIONS

There have been no changes to our related party relationships, except as described below, from those described in Note 10 of our audited financial statements filed in our 2003 Annual Report on Form 10-K, as amended.

Revenues received from related parties for the quarters ended March 31, 2004 and 2003, were approximately 13 percent of our total revenue.

Our transactions with related parties and affiliates are as follows:

	Quarter Ended March 31,	
	2004	2003
	(In thousands)	
Revenues received from related parties:		
Natural gas pipelines and plants	$20,686	$22,950
Oil and NGL logistics	8,359	6,869
	$29,045	$29,819
Expenses paid to related parties:		
Cost of natural gas and other products	$ 9,515	$14,975
Operation and maintenance	22,587	23,717
	$32,102	$38,692
Reimbursements received from related parties:		
Operation and maintenance	$ 966	$ 525

The following table provides summary data categorized by our related parties:

	Quarter Ended March 31, 2004	Quarter Ended March 31, 2003
	(In thousands)	
Revenues received from related parties:		
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 7,609	$10,812
El Paso Production Company	2,262	2,358
Tennessee Gas Pipeline Company	—	55
El Paso Field Services	18,991	16,594
Enterprise	183	—
	$29,045	$29,819
Cost of natural gas and other products paid to related parties:		
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 9,055	$10,278
El Paso Field Services	402	4,677
El Paso Natural Gas Company	19	20
Southern Natural Gas	39	—
	$ 9,515	$14,975
Operation and maintenance expenses paid to related parties:		
El Paso Corporation		
El Paso Field Services	$22,455	$23,624
Unconsolidated Subsidiaries		
Poseidon Oil Pipeline Company	132	93
	$22,587	$23,717
Reimbursements received from related parties:		
Unconsolidated Subsidiaries		
Cameron Highway	$ 217	$ —
Deepwater Gateway	183	—
Poseidon Oil Pipeline Company	566	525
	$ 966	$ 525

Our accounts receivable due from related parties consisted of the following as of:

	March 31, 2004	December 31, 2003
	(In thousands)	
El Paso Corporation		
El Paso Production Company	$ 6,373	$ 5,991
El Paso Merchant Energy North America Company	10,657	4,113
Tennessee Gas Pipeline Company	1,559	1,350
El Paso Field Services	11,113	16,571
El Paso Natural Gas Company	4,411	4,255
ANR Pipeline Company	1,662	1,600
Other	54	830
Enterprise	199	—
	36,028	34,710
Unconsolidated Subsidiaries		
Deepwater Gateway	4,319	3,939
Cameron Highway	7,375	9,302
Poseidon	1,036	—
Other	—	14
	12,730	13,255
Total	$48,758	$47,965

Our accounts payable due to related parties consisted of the following as of:

	March 31, 2004	December 31, 2003
	(In thousands)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 9,270	$ 7,523
El Paso Production Company	4,164	4,069
El Paso Field Services	13,750	13,869
Tennessee Gas Pipeline Company	973	1,278
El Paso Natural Gas Company	1,164	942
El Paso Corporation	1,322	6,249
Southern Natural Gas	20	1,871
Other	671	667
	31,334	36,468
Unconsolidated Subsidiaries		
Deepwater Gateway	2,268	2,268
Poseidon	774	—
Other	10	134
	3,052	2,402
Total	$34,386	$38,870

Other Matters

In connection with the sale of some of our Gulf of Mexico assets in January 2001, El Paso Corporation agreed to make quarterly payments to us of $2.25 million for three years beginning March 2001 and ending with a $2 million payment in the first quarter of 2004, all of which have been received.

In addition to the related party transactions discussed above, pursuant to the terms of many of the purchase and sale agreements we have entered into with various entities controlled directly or indirectly by El Paso Corporation, we have been indemnified for potential future liabilities, expenses and capital requirements above a negotiated threshold. Specifically, an indirect subsidiary of El Paso Corporation has agreed to indemnify us for specific litigation matters to the extent the ultimate resolution of these matters results in judgments against us. For a further discussion of these matters see Note 9, Commitments and Contingencies, Legal Proceedings. Some of our agreements obligate certain indirect subsidiaries of El Paso Corporation to pay for capital costs related to maintaining assets which were acquired by us, if such costs exceed negotiated thresholds. We have made claims for approximately $5 million for costs incurred during the year ended December 31, 2003, as costs exceeded the established thresholds for the year ended December 31, 2003.

We have also entered into capital contribution arrangements with entities owned by El Paso Corporation, including its regulated pipelines, in the past, and will most likely do so in the future, as part of our normal commercial activities in the Gulf of Mexico. We have an agreement to receive $6.1 million, of which $3.0 million has been collected as of March 31, 2004, from ANR Pipeline Company for our Phoenix project. These amounts collected are reflected as a reduction in project costs. Regulated pipelines often contribute capital toward the construction costs of gathering facilities owned by others which are, or will be, connected to their pipelines.

9. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Grynberg. In 1997, we, along with numerous other energy companies, were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). Discovery is proceeding. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). We, along with numerous other energy companies, are named defendants in *Will Price, et al v. Gas Pipelines and Their Predecessors, et al,* filed in 1999 in the District Court of Stevens County, Kansas. Plaintiffs allege that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands, seek certification of a nationwide class of natural gas working interest owners and natural gas royalty owners to recover royalties that they contend these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorney's fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification of a nationwide class of natural gas working interest owners and natural gas royalty owners was denied on April 10, 2003. Plaintiffs were granted leave to file a Fourth Amended Petition, which narrows the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado and removes claims as to heating content. A second class action petition has been filed as to heating content claims. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

In August 2002, we acquired the Big Thicket assets, which consist of the Vidor plant, the Silsbee compressor station and the Big Thicket gathering system located in east Texas, for approximately $11 million from BP America Production Company (BP). Pursuant to the purchase agreement, we have identified environmental conditions that we are working with BP and appropriate regulatory agencies to address. BP has agreed to indemnify us for exposure resulting from activities related to the ownership or operation of these facilities prior to our purchase (i) for a period of three years for non-environmental claims and (ii) until one year following the completion of any environmental remediation for environmental claims. Following expiration of these indemnity periods, we are obligated to indemnify BP for environmental or non-environmental claims. We, along with BP and various other defendants, have been named in the following two lawsuits for claims based on activities occurring prior to our purchase of these facilities.

Christopher Beverly and Gretchen Beverly, individually and on behalf of the estate of John Beverly v. GulfTerra GC, L.P., et. al. In June 2003, the plaintiffs sued us in state district court in Hardin County, Texas, requesting unspecified monetary damages. The plaintiffs are the parents of John Christopher Beverly, a two year old child who died on April 15, 2002, allegedly as the result of his exposure to arsenic, benzene and other harmful chemicals in the water supply. Plaintiffs allege that several defendants are responsible for that contamination, including us and BP. Our connection to the occurrences that are the basis for this suit appears to be our August 2002 purchase of certain assets from BP, including a facility in Hardin County, Texas known as the Silsbee compressor station. Under the terms of the indemnity provisions in the Purchase and Sale Agreement between us and BP, we requested that BP indemnify us for any exposure. BP has agreed to indemnify us in this matter.

Melissa Duvail, et. al., v. GulfTerra GC, L.P., et. al. In June 2003, seventy-four residents of Hardin County, Texas, sued us and others in state district court in Hardin County, Texas, requesting unspecified monetary damages. The plaintiffs allege that they have been exposed to hazardous chemicals, including arsenic and benzene, through their water supply, and that the defendants are responsible for that exposure. As with the Beverly case, our connection with the occurrences that are the basis of this suit appears to be our August 2002 purchase of certain assets from BP, including a facility known as the Silsbee compressor station, which is located in Hardin County, Texas. Under the terms of the indemnity provisions in the Purchase and Sale Agreement between us and BP, BP has agreed to indemnify us for this matter.

Commodity Futures Trading Commission Investigation. On April 2, 2004, certain affiliates of El Paso Corporation received subpoenas from the Commodity Futures Trading Commission (CFTC) in connection with the CFTC's investigation of reporting affecting the price of natural gas in the fall of 2003. Our two storage fields, Petal and Wilson, are covered by this subpoena. Specifically, the CFTC requested the companies to provide information, on behalf of themselves and their affiliates, relating to storage reports provided to the Energy Information Administration for the period October 2003 through December 2003. It is our understanding that the CFTC is conducting an industry-wide investigation of storage reporting. We are cooperating fully with the CFTC's investigation.

In connection with our April 2002 acquisition of the EPN Holding assets, subsidiaries of El Paso Corporation have agreed to indemnify us against all obligations related to existing legal matters at the acquisition date, including the legal matters involving Leapartners, L.P. and City of Edinburg discussed below.

During 2000, Leapartners, L.P. filed a suit against El Paso Field Services and others in the District Court of Loving County, Texas, alleging a breach of contract to gather and process natural gas in areas of western Texas related to an asset now owned by GulfTerra Holding. In May 2001, the court ruled in favor of Leapartners and entered a judgment against El Paso Field Services of approximately $10 million. El Paso Field Services filed an appeal with the Eighth Court of Appeals in El Paso, Texas. On August 15, 2003 the Court of Appeals reversed the lower's courts calculation of past judgment interest but otherwise affirmed the judgment. A petition for review by the Texas Supreme Court was filed, and the Supreme Court has requested full briefing of the issues.

Also, GulfTerra Texas Pipeline L.P., (GulfTerra Texas, formerly known as EPGT Texas Pipeline L.P.) now owned by GulfTerra Holding, was involved in litigation with the City of Edinburg concerning the City's claim that GulfTerra Texas was required to pay pipeline franchise fees under a contract the City had with Rio Grande Valley Gas Company, which was previously owned by GulfTerra Texas and is now owned by Southern Union Gas Company. An adverse judgment against Southern Union and GulfTerra Texas was rendered in Hidalgo County State District court in December 1998 and found a breach of contract, and held both GulfTerra Texas and Southern Union jointly and severally liable to the City for approximately $4.7 million. The judgment relied on the single business enterprise doctrine to impose contractual obligations on GulfTerra Texas and Southern Union's entities that were not parties to the contract with the City. GulfTerra Texas appealed this case to the Texas Supreme Court seeking reversal of the judgment rendered against GulfTerra Texas. The City sought a remand to the trial court of its claim of tortious interference against GulfTerra Texas. Briefs were filed and oral arguments were held in November 2002. In October 2003, the Texas Supreme Court issued an opinion in favor of GulfTerra Texas and Southern Union on all issues. The city sought rehearing which the Supreme Court denied.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we will establish the necessary accruals. As of March 31, 2004, we had no reserves for our legal matters.

While the outcome of our outstanding legal matters cannot be predicted with certainty, based on information known to date, 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. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Environmental

Each of our operating 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. As of March 2004, we had a reserve of approximately $21 million, which is included in other non-current liabilities on our balance sheets, for remediation costs expected to be incurred over time associated with mercury meters. We assumed this liability in connection with our April 2002 acquisition of the EPN Holding assets. As part of the November 2002 San Juan assets acquisition, El Paso Corporation has agreed to indemnify us for all the known and unknown environmental liabilities related to the assets we purchased up to the purchase price of $766 million. We will be indemnified for liabilities discovered during the proceeding three years from the closing date of this acquisition. In addition, we have been indemnified by third parties for remediation costs associated with other assets we have purchased. We expect to make capital expenditures for environmental matters of approximately $3 million in the aggregate for the years 2004 through 2008, primarily to comply with clean air regulations.

Shoup Air Permit Violation. On December 16, 2003, El Paso Field Services, L.P. received a Notice of Enforcement (NoE) from the Texas Commission on Environmental Quality (TCEQ) concerning alleged Clean Air Act violations at its Shoup, Texas plant. The NoE included a draft Agreed Order assessing a penalty of $365,750 for the cited violation. The alleged violations pertained to emission limit exceedences, testing, reporting, and recordkeeping issues in 2001. While the NoE was addressed to El Paso Field Services, L.P., the substance of the NoE also concerns equipment owned at the Shoup plant by GulfTerra GC, L.P. El Paso Field Services, L.P. responded to the NoE challenging several of the allegations and the penalty amount and is awaiting a response from the TCEQ.

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 environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages 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.

Rates and Regulatory Matters

Marketing Affiliate Final Rule. In November 2003, the Federal Energy Regulatory Commission (FERC) issued a Final Rule extending its standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. Since our High Island Offshore System (HIOS) natural gas pipeline and Petal natural gas storage facility, including the 60-mile Petal natural gas pipeline, are interstate facilities as defined by the Natural Gas Act, the regulations dictate how HIOS and Petal conduct business and interact with all energy affiliates of El Paso Corporation and us.

The standards of conduct require us, absent a waiver, to functionally separate our HIOS and Petal interstate facilities from our other entities. We must dedicate employees to manage and operate our interstate facilities independently from our other Energy Affiliates. This employee group must function independently and is prohibited from communicating non-public transportation information or customer information to its Energy Affiliates. Separate office facilities and systems are necessary because of the requirement to restrict affiliate access to interstate transportation information. The Final Rule also limits the sharing of employees and offices with Energy Affiliates. The Final Rule was effective on February 9, 2004, and several requests for rehearing were filed. On that date, each transmission provider filed with FERC and posted on the internet website a plan and scheduling for implementing this Final Rule. On April 8, 2004, we filed for an exemption from the rule on behalf of Petal and HIOS. On April 16, 2004, the FERC issued its order on rehearing which, among other things, affirmed that the final rule was needed and extended the implementation date to September 1, 2004. At this time, we cannot predict the impact of the final rule on HIOS and Petal's organizational structure, but at a minimum, adoption of the regulations in the form outlined in the Final Rule may place additional administrative and operational burdens on us.

Other Regulatory Matters. HIOS is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. HIOS operates under a FERC approved tariff that governs its operations, terms and conditions of service, and rates. We timely filed a required rate case for HIOS on December 31, 2002. The rate filing and tariff changes are based on HIOS' cost of service, which includes operating costs, a management fee and changes to depreciation rates and negative salvage amortization. We requested the rates be effective February 1, 2003, but the FERC suspended the rate increase until July 1, 2003, subject to refund. As of July 1, 2003, HIOS implemented the requested rates, subject to a refund, and has established a reserve for its estimate of its refund obligation. We will continue to review our expected refund obligation as the rate case moves through the hearing process and may increase or decrease the amounts reserved for refund obligation as our expectation changes. The FERC conducted a hearing on this matter and an initial decision from the Administrative Law Judge was provided in April 2004. We are in the process of filing briefs on our exceptions to this decision. We are also in separate discussions with our customers to reach a settlement on this rate case.

During the latter half of 2002, we experienced a significant unfavorable variance between the fuel usage on HIOS and the fuel collected from our customers for our use. We believe a series of events may have contributed to this variance, including two major storms that hit the Gulf Coast Region (and these assets) in late September and early October of 2002. As of March 31, 2004, we had recorded fuel differences of approximately $7.3 million, which is included in other non-current assets on our balance sheets. We are currently in discussions with the FERC as well as our customers regarding the potential collection of some or all of the fuel differences. Any amount we are unable to resolve or collect from our customers will negatively impact our earnings. At this time we are not able to determine what amount, if any, may be collectible from our customers.

In December 1999, GulfTerra Texas filed a petition with the FERC for approval of its rates for interstate transportation service. In June 2002, the FERC issued an order that required revisions to GulfTerra Texas' proposed maximum rates. The changes ordered by the FERC involve reductions to rate of return, depreciation rates and revisions to the proposed rate design, including a requirement to separately state rates for gathering service. FERC also ordered refunds to customers for the difference, if any, between the originally proposed levels and the revised rates ordered by the FERC. We believe the amount of any rate refund would be minimal since most transportation services are discounted from the maximum rate. GulfTerra Texas has established a reserve for refunds. In July 2002, GulfTerra Texas requested rehearing on certain issues raised by the FERC's order, including the depreciation rates and the requirement to separately state a gathering rate. On February 25, 2004, the FERC issued an order denying GulfTerra Texas' request for rehearing and ordered GulfTerra Texas to file, within 45 days from the issuance of the order, a calculation of refunds and a refund plan. On March 22, 2004, the FERC extended the 45 day time limit to July 12, 2004. Additionally, the FERC ordered GulfTerra Texas to file a new rate case or justification of existing rates within three years from the date of the order. In March 2004, GulfTerra Texas filed for rehearing of the triennial rate case requirement. The FERC plans to issue an order on rehearing of the triennial rate case requirement by June 21, 2004.

In July 2002, Falcon Gas Storage, a competitor, also requested late intervention and rehearing of the order. Falcon asserts that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering imbalance management services. The FERC denied Falcon's late intervention in February 2004. Meanwhile in December 2002, GulfTerra Texas amended its Statement of Operating Conditions to provide shippers the option of resolving daily imbalances using a third-party imbalance service provider.

Falcon filed a formal complaint in March 2003 at the Railroad Commission of Texas claiming that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering hourly imbalance management services on the GulfTerra Texas system. GulfTerra Texas filed a response specifically denying Falcon's assertions and requesting that the complaint be denied. The Railroad Commission has set their case for hearing beginning on June 29, 2004. The City Board of Public Service of San Antonio filed an intervention in opposition to Falcon's complaint.

While the outcome of all of our rates and regulatory matters cannot be predicted with certainty, based on information known to date, 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. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Joint Ventures

We conduct a portion of our business through joint venture arrangements (including our Cameron Highway, Deepwater Gateway and Poseidon joint ventures) we form 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.

10. ACCOUNTING FOR HEDGING ACTIVITIES

A majority of our commodity purchases and sales, which relate to sales of oil and natural gas associated with our production operations, purchases and sales of natural gas associated with pipeline operations, sales of natural gas liquids and purchases or sales of gas associated with our processing plants and our gathering activities, are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities.

We estimate the entire $13.3 million of unrealized losses included in accumulated other comprehensive income at March 31, 2004, will be reclassified from accumulated other comprehensive income as a reduction to earnings over the next nine months. When our derivative financial instruments are settled, the related amount in accumulated other comprehensive income is recorded in the income statement in operating revenues, cost of natural gas and other products, or interest and debt expense, depending on the item being hedged. The effect of reclassifying these amounts to the income statement line items is recording our earnings for the period related to the hedged items at the "hedged price" under the derivative financial instruments.

In February and August 2003, we entered into derivative financial instruments to continue to hedge our exposure during 2004 to changes in natural gas prices relating to gathering activities in the San Juan Basin. The derivatives are financial swaps on 30,000 MMBtu per day whereby we receive an average fixed price of $4.23 per MMBtu and pay a floating price based on the San Juan index. As of March 31, 2004, the fair value of these cash flow hedges was a liability of $9.2 million, as the market price at that date was higher than the hedge price. For the quarter ended March 31, 2004, we reclassified approximately $1.7 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income as a decrease in revenue. No ineffectiveness exists in this hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

During 2003, we entered into additional derivative financial instruments to hedge a portion of our business' exposure to changes in natural gas liquids (NGL) prices during 2004. We entered into financial swaps for 6,000 barrels per day for the period from August 2003 to September 2004. The average fixed price received is $0.47 per gallon for 2004 while we pay a monthly average floating price based on the Oil Pricing Information Service (OPIS) average price for each month. As of March 31, 2004, the fair value of these cash flow hedges was a liability of $4.1 million. For the quarter ended March 31, 2004, we reclassified approximately $2.1 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income to earnings. No ineffectiveness exists in this hedging relationship because all purchase and sales prices are based on the same index and volumes as the hedge transaction.

In connection with our GulfTerra Intrastate Alabama operations, we have fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We entered into cash flow hedges in 2003 to offset the risk of increasing natural gas prices. For January and February 2004, we contracted to purchase 20,000 MMBtu and for March 2004, we contracted to purchase 15,000 MMBtu. The average fixed price paid during 2004 was $5.28 per MMBtu while we received a floating price based on the SONAT-Louisiana index (Southern Natural Pipeline index as published by the periodical "Inside FERC"). As of March 31, 2004, these cash flow hedges expired and we reclassified a gain of approximately $45 thousand from accumulated other comprehensive income to earnings. No ineffectiveness existed in this hedging relationship because all purchase and sale prices were based on the same index and volumes as the hedge transaction.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we paid the counterparty a LIBOR based interest rate plus a spread of 4.20% and received a fixed rate of 8½%. We accounted for this derivative as a fair value hedge under SFAS No. 133. In March 2004, we terminated our fixed to floating interest rate swap with our counterparty. The value of the transaction at termination was zero and as such neither we, nor our counterparty, were required to make any payments. Also, neither we, nor our counterparty, have any future obligations under this transaction.

The counterparties for our San Juan hedging activities are J. Aron and Company, an affiliate of Goldman Sachs, and UBS Warburg. We do not require collateral and do not anticipate non-performance by these counterparties. The counterparty for our GulfTerra Alabama Intrastate operations is UBS Warburg, and we do not require collateral or anticipate non-performance by this counterparty.

11. BUSINESS SEGMENT INFORMATION

Each of our segments are business units that offer different services and products that are managed separately since each segment requires different technology and marketing strategies. We have segregated our business activities into four distinct operating segments:

- Natural gas pipelines and plants;
- Oil and NGL logistics;
- Natural gas storage; and
- Platform services.

We use performance cash flows (which we formerly referred to as EBITDA) to evaluate the performance of our segments, determine how resources will be allocated and develop strategic plans. We define performance cash flows as earnings before interest, depreciation and amortization and other adjustments. Historically our lenders and equity investors have viewed our performance cash flows measure as an indication of our ability to generate sufficient cash to meet debt obligations or to pay distributions. We believe that there has been a shift in investors' evaluation regarding investments in MLPs and they now put as much focus on the performance of an MLP investment as they do its ability to pay distributions. For that reason, we disclose performance cash flows as a measure of our segment's performance.

We believe performance cash flows is also useful to our investors because it allows them to evaluate the effectiveness of our business segments from an operational perspective, exclusive of the costs to finance those activities and depreciation and amortization, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures.

The following are results as of and for the quarters ended March 31:

	Natural Gas Pipelines and Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Non-Segment Activity[1]	Total
			(In thousands)			
Quarter Ended March 31, 2004						
Revenue from external customers	$ 181,503	$ 15,188	$ 12,450	$ 6,642	$ 4,556	$ 220,339
Intersegment revenue	33	—	—	585	(618)	—
Depreciation, depletion and amortization	17,388	3,092	2,948	1,353	1,442	26,223
Earnings from unconsolidated affiliates	534	1,790	(30)	(86)	—	2,208
Performance cash flows	82,013	7,468	9,061	6,363	N/A	N/A
Assets	2,329,952	472,482	311,326	167,044	83,212	3,364,016
Quarter Ended March 31, 2003						
Revenue from external customers[2]	$ 197,189	$ 11,968	$ 11,606	$ 4,382	$ 4,950	$ 230,095
Intersegment revenue	38	—	92	646	(776)	—
Depreciation, depletion and amortization	16,553	2,197	2,962	1,200	785	23,697
Earnings from unconsolidated affiliates	629	2,687	—	—	—	3,316
Performance cash flows	77,835	11,600	7,001	4,235	N/A	N/A
Assets	2,249,828	322,324	326,795	160,128	108,407	3,167,482

(1) Represents predominantly our oil and natural gas production activities as well as intersegment eliminations. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Non-Segment Activity" column, to remove intersegment transactions.

(2) Revenue from external customers for our Oil and NGL Logistics segment has been reduced by $48.8 million to reflect the revision of Typhoon Oil Pipeline's revenues and cost of natural gas and other products to conform to the current period presentation. See Note 1, Basis of Presentation and Summary of Significant Accounting Policies; Revenue Recognition and Cost of Natural Gas and Other Products.

A reconciliation of our segment performance cash flows to our net income is as follows:

	Quarter Ended March 31,	
	2004	2003
	(In thousands)	
Natural gas pipelines and plants	$ 82,013	$ 77,835
Oil and NGL logistics	7,468	11,600
Natural gas storage	9,061	7,001
Platform services	6,363	4,235
Segment performance cash flows	104,905	100,671
Plus: Other, nonsegment results	5,405	5,266
Earnings from unconsolidated affiliates	2,208	3,316
Cumulative effect of accounting change	—	1,690
Less: Interest and debt expense	28,031	34,486
Loss due to write-off of unamortized debt issuance costs	—	3,762
Depreciation, depletion and amortization	26,223	23,697
Cash distributions from unconsolidated affiliates	750	4,710
Minority interest	(12)	33
Net cash payment received from El Paso Corporation	1,960	2,040
Net income	$ 55,566	$ 42,215

12. GUARANTOR FINANCIAL INFORMATION

As of March 31, 2004 and December 31, 2003, our credit facility is guaranteed by each of our subsidiaries, excluding our unrestricted subsidiaries (Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.), and is collateralized by substantially all of our assets. In addition, all of our senior notes and senior subordinated notes are jointly, severally, fully and unconditionally guaranteed by us and all of our subsidiaries, excluding our unrestricted subsidiaries. Non-guarantor subsidiaries for the quarter ended March 31, 2004, consisted of our unrestricted subsidiaries. Non-guarantor subsidiaries for the quarter ended March 31, 2003, consisted of Matagorda Island Area Gathering System, Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.

The following condensed consolidating financial statements are included so that separate financial statements of our guarantor subsidiaries are not required to be filed with the SEC. These condensed consolidating financial statements present our investments in both consolidated subsidiaries and unconsolidated affiliates using the equity method of accounting. The consolidating eliminations column on our condensed consolidating balance sheets below eliminates our investment in consolidated subsidiaries, intercompany payables and receivables and other transactions between subsidiaries. The consolidating eliminations column in our condensed consolidating statements of income and cash flows eliminates earnings from our consolidated affiliates.

Condensed Consolidating Statements of Income
Quarter Ended March 31, 2004

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$134	$220,205	$ —	$220,339
Operating expenses					
Cost of natural gas and other products	—	—	64,427	—	64,427
Operation and maintenance	—	63	48,433	—	48,496
Depreciation, depletion and amortization	36	—	26,187	—	26,223
Gain on sale of long-lived assets	—	—	(24)	—	(24)
	36	63	139,023	—	139,122
Operating income (loss)	(36)	71	81,182	—	81,217
Earnings from consolidated affiliates	65,833	—	—	(65,833)	—
Earnings (loss) from unconsolidated affiliates	—	(30)	2,238	—	2,208
Minority interest income	—	12	—	—	12
Other income	73	—	87	—	160
Interest and debt expense	10,304	(7)	17,734	—	28,031
Net income	$55,566	$ 60	$ 65,773	$(65,833)	$ 55,566

Condensed Consolidating Statements of Income
Quarter Ended March 31, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries[1]	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$277	$229,818	$ —	$230,095
Operating expenses					
Cost of natural gas and other products	—	—	90,753	—	90,753
Operation and maintenance	467	74	40,103	—	40,644
Depreciation, depletion and amortization	37	10	23,650	—	23,697
Gain on sale of long-lived assets	—	—	(106)	—	(106)
	504	84	154,400	—	154,988
Operating income (loss)	(504)	193	75,418	—	75,107
Earnings from consolidated affiliates	61,505	—	—	(61,505)	—
Earnings from unconsolidated affiliates	—	—	3,316	—	3,316
Minority interest expense	—	(33)	—	—	(33)
Other income	248	—	135	—	383
Interest and debt expense	15,272	—	19,214	—	34,486
Loss due to write-off of unamortized debt issuance costs	3,762	—	—	—	3,762
Income before cumulative effect of accounting change	42,215	160	59,655	(61,505)	40,525
Cumulative effect of accounting change	—	—	1,690	—	1,690
Net income	$42,215	$160	$ 61,345	$(61,505)	$ 42,215

(1) Operating revenues and cost of natural gas and other products for our guarantor subsidiaries has been reduced by $48.8 million to reflect the revision of Typhoon Oil Pipeline's revenues and cost of natural gas and other products to conform to the current period presentation. See Note 1, Basis of Presentation and Summary of Significant Accounting Policies; Revenue Recognition and Cost of Natural Gas and Other Products.

Condensed Consolidating Balance Sheets
March 31, 2004

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 23,257	$ —	$ —	$ —	$ 23,257
Accounts receivable, net					
Trade	2,287	80	115,307	—	117,674
Affiliates	747,417	206	44,331	(743,196)	48,758
Affiliated note receivable	—	3,713	—	—	3,713
Other current assets	6,675	—	16,850	—	23,525
Total current assets	779,636	3,999	176,488	(743,196)	216,927
Property, plant and equipment, net	8,508	431	2,907,545	—	2,916,484
Intangible assets	—	—	3,309	—	3,309
Investment in unconsolidated affiliates	—	—	190,732	—	190,732
Investment in consolidated affiliates	2,169,692	—	700	(2,170,392)	—
Other noncurrent assets	198,495	—	8,068	(169,999)	36,564
Total assets	$3,156,331	$4,430	$3,286,842	$(3,083,587)	$3,364,016
Current liabilities					
Accounts payable					
Trade	$ —	$ 17	$ 105,454	$ —	$ 105,471
Affiliates	9,101	—	768,481	(743,196)	34,386
Accrued interest	33,982	—	—	—	33,982
Current maturities of senior secured term loan	3,000	—	—	—	3,000
Other current liabilities	7,171	—	33,531	—	40,702
Total current liabilities	53,254	17	907,466	(743,196)	217,541
Revolving credit facility	387,000	—	—	—	387,000
Senior secured term loans, less current maturities	297,000	—	—	—	297,000
Long-term debt	1,137,161	—	—	—	1,137,161
Other noncurrent liabilities	(1)	—	211,596	(169,999)	41,596
Minority interest	—	1,801	—	—	1,801
Partners' capital	1,281,917	2,612	2,167,780	(2,170,392)	1,281,917
Total liabilities and partners' capital	$3,156,331	$4,430	$3,286,842	$(3,083,587)	$3,364,016

Condensed Consolidating Balance Sheets
December 31, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 30,425	$ —	$ —	$ —	$ 30,425
Accounts receivable, net					
Trade	—	113	106,157	—	106,270
Affiliates	746,126	3,541	41,606	(743,308)	47,965
Affiliated note receivable	—	3,713	55	—	3,768
Other current assets	3,573	—	17,022	—	20,595
Total current assets	780,124	7,367	164,840	(743,308)	209,023
Property, plant and equipment, net	8,039	431	2,886,022	—	2,894,492
Intangible assets	—	—	3,401	—	3,401
Investment in unconsolidated affiliates	—	—	175,747	—	175,747
Investment in consolidated affiliates	2,108,104	—	622	(2,108,726)	—
Other noncurrent assets	199,761	—	9,155	(169,999)	38,917
Total assets	$3,096,028	$7,798	$3,239,787	$(3,022,033)	$3,321,580
Current liabilities					
Accounts payable					
Trade	$ —	$ 22	$ 129,241	$ —	$ 129,263
Affiliates	10,691	3,499	767,988	(743,308)	38,870
Accrued interest	10,930	—	269	—	11,199
Current maturities of senior secured term loan	3,000	—	—	—	3,000
Other current liabilities	2,601	1	24,433	—	27,035
Total current liabilities	27,222	3,522	921,931	(743,308)	209,367
Revolving credit facility	382,000	—	—	—	382,000
Senior secured term loan, less current maturities	297,000	—	—	—	297,000
Long-term debt	1,129,807	—	—	—	1,129,807
Other noncurrent liabilities	7,413	—	211,629	(169,999)	49,043
Minority interest	—	1,777	—	—	1,777
Partners' capital	1,252,586	2,499	2,106,227	(2,108,726)	1,252,586
Total liabilities and partners' capital	$3,096,028	$7,798	$3,239,787	$(3,022,033)	$3,321,580

Condensed Consolidating Statements of Cash Flows
Quarter Ended March 31, 2004

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 55,566	$ 60	$ 65,773	$(65,833)	$ 55,566
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	36	—	26,187	—	26,223
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	30	(2,238)	—	(2,208)
Distributions from unconsolidated affiliates	—	—	750	—	750
Gain on sale of long-lived assets	—	—	(24)	—	(24)
Amortization of debt issuance costs	1,358	—	—	—	1,358
Other noncash items	604	24	2,408	—	3,036
Working capital changes, net of effects of acquisitions and noncash transactions	22,518	(61)	(43,698)	—	(21,241)
Net cash provided by operating activities	80,082	53	49,158	(65,833)	63,460
Cash flows from investing activities					
Additions to property, plant and equipment	(505)	—	(47,328)	—	(47,833)
Proceeds from sale and retirement of assets	—	—	93	—	93
Additions to investments in unconsolidated affiliates	—	—	(5,800)	—	(5,800)
Net cash used in investing activities	(505)	—	(53,035)	—	(53,540)
Cash flows from financing activities					
Net proceeds from revolving credit facility	44,933	—	—	—	44,933
Repayments of revolving credit facility	(40,000)	—	—	—	(40,000)
Net proceeds from senior secured term loan	(57)	—	—	—	(57)
Net proceeds from issuance of long-term debt	(30)	—	—	—	(30)
Net proceeds from issuance of common units	48,274	—	—	—	48,274
Advances with affiliates	(69,657)	(53)	3,877	65,833	—
Distributions to partners	(70,529)	—	—	—	(70,529)
Contribution from general partner	321	—	—	—	321
Net cash provided by (used in) financing activities	(86,745)	(53)	3,877	65,833	(17,088)
Decrease in cash and cash equivalents	$ (7,168)	$ —	$ —	$ —	(7,168)
Cash and cash equivalents at beginning of period					30,425
Cash and cash equivalents at end of period					$ 23,257

Condensed Consolidating Statements of Cash Flows
Quarter ended March 31, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 42,215	$ 160	$ 61,345	$(61,505)	$ 42,215
Less cumulative effect of accounting change	—	—	1,690	—	1,690
Income before cumulative effect of accounting change	42,215	160	59,655	(61,505)	40,525
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	37	10	23,650	—	23,697
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	—	(3,316)	—	(3,316)
Distributions from unconsolidated affiliates	—	—	4,710	—	4,710
Gain on sale of long-lived assets	—	—	(106)	—	(106)
Loss due to write-off of unamortized debt issuance costs	3,762	—	—	—	3,762
Amortization of debt issuance costs	1,938	—	154	—	2,092
Other noncash items	270	33	220	—	523
Working capital changes, net of effects of acquisitions and noncash transactions	17,888	(170)	(18,161)	—	(443)
Net cash provided by operating activities	66,110	33	66,806	(61,505)	71,444
Cash flows from investing activities					
Additions to property, plant and equipment	(309)	—	(81,628)	—	(81,937)
Proceeds from sale and retirement of assets	—	—	3,088	—	3,088
Additions to investments in unconsolidated affiliates	—	(133)	—	—	(133)
Net cash used in investing activities	(309)	(133)	(78,540)	—	(78,982)
Cash flows from financing activities					
Net proceeds from revolving credit facility	98,991	—	—	—	98,991
Repayments of revolving credit facility	(119,000)	—	—	—	(119,000)
Repayment of senior secured acquisition term loan	(237,500)	—	—	—	(237,500)
Net proceeds from issuance of long-term debt	293,277	—	—	—	293,277
Advances with affiliates	(63,775)	100	2,170	61,505	—
Distributions to partners	(52,080)	—	—	—	(52,080)
Net cash provided by (used in) financing activities	(80,087)	100	2,170	61,505	(16,312)
Decrease in cash and cash equivalents	$ (14,286)	$ —	$ (9,564)	$ —	(23,850)
Cash and cash equivalents at beginning of period					36,099
Cash and cash equivalents at end of period					$ 12,249

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

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in Part II, Items 7, 7A and 8, in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2003, in addition to the interim financial statements and notes presented in Item 1 of this Quarterly Report on Form 10-Q.

In the first quarter of 2004, we advanced numerous Gulf of Mexico pipeline and platform projects which will make contributions in the second half of 2004 and we continued to make progress on our planned merger with Enterprise. The Marco Polo TLP was installed in the first quarter and is being commissioned by Anadarko Petroleum Corporation with expected first deliveries in early summer. Construction on our Marco Polo oil and gas gathering systems is largely complete. Additionally, the Cameron Highway oil pipeline system project is on track to be placed in-service later this year with first production expected in late 2004. Additionally, our Phoenix gathering system is largely complete and we expect first production by mid-year from Kerr-McGee's Red Hawk Deepwater development.

Merger with Enterprise

On December 15, 2003, we, along with Enterprise and El Paso Corporation, announced that we had executed definitive agreements to merge Enterprise and GulfTerra to form one of the largest publicly traded MLPs.

In April 2004, Enterprise and El Paso Corporation amended their agreement with respect to the ownership of Enterprise's general partner interest upon the completion of our merger with Enterprise.

As originally envisioned in the merger agreement, El Paso Corporation was to contribute its 50-percent ownership interest in our general partner to Enterprise's general partner, in exchange for a 50-percent ownership interest in Enterprise's general partner. Under the amended transaction, El Paso Corporation will still contribute its 50-percent ownership interest in our general partner to Enterprise's general partner, but in exchange, El Paso Corporation will receive a 9.9-percent ownership interest in Enterprise's general partner and $370 million in cash. The remaining 90.1-percent ownership interest in Enterprise's general partner will continue to be owned by affiliates of privately-held Enterprise Products Company.

The remaining transactions with respect to our merger with Enterprise are unchanged. These include:

- the payment of $500 million in cash from Enterprise to El Paso Corporation for approximately 13.8 million units, which include 2.9 million of our common units and all of our Series C units owned by El Paso Corporation;

- the exchange of 1.81 Enterprise common units for each GulfTerra common unit owned by GulfTerra's unitholders, including the remaining approximately 7.5 million GulfTerra common units owned by El Paso Corporation.

Merger Related Costs

As a result of the pending merger with Enterprise, we determined that it was in our and our unitholders' best interest to offer selected employees of El Paso Corporation incentives to continue to focus on the business of the partnership during the merger process. We have accounted for these incentives under the provisions of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* As of March 31, 2004, we recorded a liability and a related deferred charge of $4.3 million, which are reflected in other current liabilities and other current assets on our balance sheets. Our liability was estimated based upon the number of employees accepting the offer and the discounted amount they are expected to be paid. We are amortizing the deferred asset to expense ratably over the expected period of the services required in order to qualify for receiving the payments. We expect to amortize the entire expense by merger close. During the quarter ended March 31, 2004, we had amortized $0.6 million to expense. If our expectations of future amounts to be paid or the period of service to be rendered change, we will adjust our liability.

Additionally, during the first quarter of 2004, we recognized an expense of $3.5 million associated with a fairness opinion we received on our pending merger with Enterprise. All of our merger related costs are included in operation and maintenance expenses on our statements of income and are allocated across all of our operating segments.

Liquidity and Capital Resources

Our principal requirements for cash, other than our routine operating costs, are for capital expenditures, debt service, business acquisitions and distributions to our partners. We plan to fund our short-term cash needs, including operating costs, maintenance capital expenditures and cash distributions to our partners, from cash generated from our operating activities and borrowings under our credit facility. Capital expenditures we expect to benefit us over longer time periods, including our organic growth projects and business acquisitions, we plan to fund through a variety of sources (either separately or in combination), which include issuing additional common units, borrowing under commercial bank credit facilities, issuing public or private placement debt and other financing transactions. We plan to fund our debt service requirements through a combination of refinancing arrangements and cash generated from our operating activities. As previously discussed, our merger agreement with Enterprise limits our ability to raise additional capital and incur additional indebtedness prior to the closing of the merger without Enterprise's approval; however, we believe that these limitations will not affect our liquidity.

Capital Resources

Series F Convertible Units

In connection with a public offering in May 2003, we issued 80 Series F convertible units convertible into a maximum of 8,329,679 common units and comprised of two separate detachable units. The Series F1 units are convertible into up to $80 million of common units anytime after August 12, 2003, and until the date we merge with Enterprise (subject to other defined extension rights). The Series F2 units are convertible into up to $40 million of common units prior to March 30, 2005 (subject to defined extension rights). The price at which the Series F convertible units may be converted to common units is equal to the lesser (i) of the prevailing price (as defined below), if the prevailing price is equal to or greater than $35.75, or (ii) the prevailing price minus the product of 50 percent of the positive difference, if any, of $35.75 minus the prevailing price. The prevailing price is equal to the lesser of (i) the average closing price of our common units for the 60 business days ending on and including the fourth business day prior to our receiving notice from the holder of the Series F convertible units of their intent to convert them into common units, (ii) the average closing price of our common units for the first seven business days of the 60 day period included in (i); or (iii) the average closing price of our common units for the last seven business days of the 60 day period included in (i). The price at which the Series F convertible units could have been converted to common units, assuming we had received a conversion notice on March 31, 2004 and May 3, 2004, was $41.12 and $39.01 per common unit. Holders of Series F convertible units are not entitled to vote or to receive distributions. The value of the Series F convertible units was $2.6 million as of March 31, 2004, and is included in partners' capital as a component of common units.

In August 2003, we amended the terms of the Series F convertible units to permit the holder to elect a "cashless" exercise — that is, an exercise where the holder gives up common units with a value equal to the exercise price rather than paying the exercise price in cash. If the holder so elects, we have the option to settle the net position by issuing common units or, if the settlement price per unit is above $26 per unit, paying the holder an amount of cash equal to the market price of the net number of units. These amendments had no effect on the classification of the Series F convertible units on the balance sheet at March 31, 2004 and December 31, 2003.

In the first quarter of 2004, 45 Series F1 convertible units were converted into 1,146,418 common units, for which the holder of the convertible units paid us $45 million. Additionally, our general partner contributed to us $0.3 million in cash in order to maintain its one percent general partner interest.

Any Series F1 convertible units for which a conversion notice has not been delivered prior to the merger closing date, or termination of the merger, will expire upon the closing, or termination, of the merger with

Enterprise. Any Series F2 convertible units outstanding at the merger date will be converted into rights to receive Enterprise common units, subject to the restrictions governing the Series F units. The number of Enterprise common units and the price per unit at conversion will be adjusted based on the 1.81 exchange ratio.

Indebtedness and Other Obligations

In March 2004, we gave notice to exercise our right, under the terms of our senior subordinated notes' indentures, to repay, at a premium, approximately $39.1 million in principal amount of our 8½% senior subordinated notes due June 2010. We will recognize additional costs totaling $4.1 million resulting from the payment of the redemption premiums and the write-off of unamortized debt issuance costs. We will account for these costs as an expense during the second quarter of 2004 in accordance with the provisions of SFAS No. 145.

In April 2004, we initiated a full redemption of all our outstanding $175 million aggregate principal amount of 10⅜% senior subordinated notes due 2009. The notes will be redeemed on June 1, 2004, at a redemption price of 105.2% of the principal amount, plus accrued and unpaid interest to June 1, 2004. Interest on the notes will cease to accrue on and after June 1, 2004, and the only remaining right of holders of the notes will be to receive payment of the redemption price upon surrender to the paying agent, plus accrued and unpaid interest up to, but not including, June 1, 2004. In connection with the redemption of the notes, we will recognize additional expense during the second quarter of 2004 totaling $12.1 million resulting from the payment of the redemption premium and the write-off of unamortized debt issuance costs. We will fund the redemption with internally generated funds and borrowings under our credit facility.

See Item 1., Financial Statements, Note 5, for additional discussion of our debt obligations.

The following table presents the timing and amounts of our debt repayment and other obligations for the years following March 31, 2004, that we believe could affect our liquidity (in millions):

Debt Repayment and Other Obligations	<1 Year	1-3 Years	3-5 Years	After 5 Years	Total
Revolving credit facility	$ —	$387	$ —	$ —	$ 387
Senior secured term loan	3	6	291	—	300
6¼% senior notes issued July 2003, due June 2010	—	—	—	250	250
10⅜% senior subordinated notes issued May 1999, due June 2009	—	—	—	175	175
8½% senior subordinated notes issued March 2003, due June 2010	—	—	—	255	255
8½% senior subordinated notes issued May 2001, due June 2011	—	—	—	168	168
8½% senior subordinated notes issued May 2002, due June 2011	—	—	—	154	154
10⅝% senior subordinated notes issued November 2002, due December 2012	—	—	—	134	134
Wilson natural gas storage facility operating lease	5	10	5	—	20
Texas leased NGL storage facilities	2	2	1	2	7
Total debt repayment and other obligations	$ 10	$405	$297	$1,138	$1,850

The close of the merger will constitute a change of control, and thus a default, under our credit facility, therefore we will either repay or amend that facility prior to the close. In addition, the merger close will constitute a change of control under our indentures, and we will be required to offer to repurchase our outstanding senior subordinated notes (and possibly our senior notes) at 101 percent of their principal amount after the close. In coordination with Enterprise, we are evaluating alternative financing plans in preparation for the close of the merger. We and Enterprise can agree on the date of the merger close after the receipt of all necessary approvals. We do not intend to close until appropriate financing is in place.

Industrial Revenue Bonds

In April 2004, we reduced the sales tax assessable by the State of Mississippi related to our Petal natural gas storage expansion and pipeline project completed in September 2002, by completing that project's qualification for tax incentives available under the MBFA. To complete the qualification, Petal, our indirect, wholly-owned subsidiary, borrowed $52 million from the MBFC pursuant to a loan agreement between Petal and the MBFC. On the same date, the MBFC issued $52.0 million in Industrial Development Revenue Bonds to us. The loan agreement and the Industrial Development Revenue Bonds have identical interest rates of 6.25% and maturities of fifteen years. The bonds and tax exemptions are authorized under the MBFA. 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.

Capital Expenditures

The ability to execute our growth strategy and complete our projects is dependent upon our access to the capital necessary to fund projects and acquisitions. Our success with capital raising efforts, including the formation of joint ventures to share costs and risks, continues to be the critical factor which determines how much we actually spend. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs and, although we currently intend to make the forecasted expenditures discussed below, we may adjust the timing and amounts of projected expenditures as necessary to adapt to changes in the capital markets.

Under the merger agreement with Enterprise, we can not make capital expenditures, without Enterprise's consent, in excess of $5 million or $25 million in the aggregate other than (1) as required on an emergency basis and (2) those planned expenditures previously disclosed to Enterprise. The forecasted expenditures disclosed in the tables below were either consented to by Enterprise, planned expenditures previously disclosed to Enterprise or expenditures which fall within the monetary thresholds in the merger agreement.

We estimate our forecasted expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the capital necessary to accomplish our operating and growth objectives. These estimates may change due to factors beyond our control, such as weather related issues, changes in supplier prices or poor economic conditions. Further, estimates may change as a result of decisions made at a later date, which may include acquisitions, scope changes or decisions to take on additional partners. Our projection of expenditures for the quarter March 31, 2004 as presented in our 2003 Annual Report on Form 10-K, as amended, was $76 million; however, our actual expenditures were approximately $48 million.

The table below depicts our estimate of projects and capital maintenance expenditures through March 31, 2005. These estimates are net of anticipated contributions in aid of construction and contributions from joint venture partners. We expect to be able to fund these forecasted expenditures from the combination of operating cash flow and funds available under our revolving credit facility and other financing arrangements. Actual results may vary from these projections. We do not disclose planned expenditures related to our offshore projects unless we have signed definitive agreements to proceed.

Forecasted Expenditures

	Quarters Ending				Net Total Forecasted Expenditures
	June 30, 2004	September 30, 2004	December 31, 2004	March 31, 2005	
			(In millions)		
Net Forecasted Capital Project Expenditures	$42	$11	$18	$10	$ 81
Other Forecasted Capital Expenditures	13	10	5	10	38
Additional Capital Contributions to Our Unconsolidated Affiliates	11	8	3	—	22
Total Forecasted Expenditures	$66	$29	$26	$20	$141

Construction Projects

	Capital Expenditures				Capacity		
	Forecasted		As of March 31, 2004				
	Total[1]	GulfTerra[2]	Total[1]	GulfTerra[2]	Oil	Natural Gas	Expected In-Service
	(In millions)				(MBbls/d)	(MMcf/d)	
Wholly owned projects							
Marco Polo Natural Gas and Oil Pipelines	$ 106	$ 89	$ 97	$ 80	120	400	Mid-Year 2004
Phoenix Gathering System	66	60	59	56	—	450	Mid-Year 2004
Petal Conversion Project	17	17	—	—	—	1.8[3]	Fourth Quarter 2004
Joint venture projects							
Marco Polo Tension Leg Platform	239	49	231	39	120	300	Second Quarter 2004
Cameron Highway Oil Pipeline	464	95	386	85	500	—	Fourth Quarter 2004

(1) Includes 100 percent of costs and is not reduced for anticipated contributions in aid of construction, project financings and contributions from joint venture partners. We expect to receive $6.1 million (of which $3.0 million has been collected as of March 31, 2004) from ANR Pipeline Company for our Phoenix project. We have received $10.5 million from ANR Pipeline Company and $7.0 million from El Paso Field Services for the Marco Polo natural gas pipeline.

(2) GulfTerra expenditures are net of anticipated or received contributions in aid of construction, project financings and contributions from joint venture partners, to the extent applicable.

(3) Capacity in Bcf

Petal Conversion Project

We are planning, subject to final regulatory approval, to convert our existing brine well at our propane storage caverns in Hattiesburg, Mississippi to natural gas service. This conversion will cost approximately $17 million and will create a new 1.8 Bcf working natural gas cavern that would be integrated into our Petal natural gas storage facility. We are currently negotiating with customers for contracts to subscribe the 1.8 Bcf capacity and expect to have the cavern in service during the fourth quarter of 2004. We expect to fund the conversion project costs through internally generated funds and borrowings under our credit facility.

Cash From Operating Activities

Net cash provided by operating activities was $63.5 million for the quarter ended March 31, 2004, compared to $71.4 million for the same period in 2003. The decrease was primarily attributable to changes in working capital and lower distributions from our unconsolidated affiliate, Poseidon, due to Poseidon's construction of the Front Runner oil pipeline. This decrease was partially offset by higher operating cash flows generated by our Texas intrastate pipeline system, natural gas storage assets, and Falcon Nest platform.

Cash Used In Investing Activities

Net cash used in investing activities was approximately $53.5 million for the quarter ended March 31, 2004. Our investing activities included capital expenditures of $47.8 million primarily related to our Marco Polo pipelines, Phoenix gathering system and the San Juan optimization project, as well as maintenance expenditures primarily related to our Chaco plant, GulfTerra Texas Intrastate system and our NGL pipeline systems. Our investing activities also included additions to investments in unconsolidated affiliates of $5.8 million related to additional equity contributions we made to Deepwater Gateway for the construction of the Marco Polo TLP.

Cash Used in Financing Activities

Net cash used in financing activities was approximately $17.1 million for the quarter ended March 31, 2004. During 2004, cash used in our financing activities included repayments on our revolving credit facility, as well as distributions to our partners. Cash provided by financing activities included the proceeds received from the conversion of Series F1 convertible units into common units, the proceeds received from the exercise of unit options and the proceeds from borrowings under our revolving credit facility.

Results of Operations

Our business activities are segregated into four distinct operating segments:

- Natural gas pipelines and plants;
- Oil and NGL logistics;
- Natural gas storage; and
- Platform services.

Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. For a further discussion of the individual segments, see Item 1., Financial Statements, Note 11. For the past two years, inflation has not had a material effect on any of our financial results.

Segment Results

We use performance cash flows (which we formerly referred to as EBITDA) to evaluate the performance of our segments, determine how resources will be allocated and develop strategic plans. We define performance cash flows as earnings before interest, depreciation and amortization and other adjustments. Historically our lenders and equity investors have viewed our performance cash flows measure as an indication of our ability to generate sufficient cash to meet debt obligations or to pay distributions. We believe that there has been a shift in investors' evaluation regarding investments in MLPs and they now put as much focus on the performance of an MLP investment as they do its ability to pay distributions. For that reason, we disclose performance cash flows as a measure of our segment's performance.

We believe performance cash flows is also useful to our investors because it allows them to evaluate the effectiveness of our business segments from an operational perspective, exclusive of the costs to finance those activities and depreciation and amortization, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures.

A reconciliation of our segment performance cash flows to our net income is as follows:

	Quarter Ended March 31, 2004	Quarter Ended March 31, 2003
	(In thousands)	
Natural gas pipelines and plants	$ 82,013	$ 77,835
Oil and NGL logistics	7,468	11,600
Natural gas storage	9,061	7,001
Platform services	6,363	4,235
Segment performance cash flows	104,905	100,671
Plus: Other, nonsegment results	5,405	5,266
Earnings from unconsolidated affiliates	2,208	3,316
Cumulative effect of accounting change	—	1,690
Less: Interest and debt expense	28,031	34,486
Loss due to write-off of unamortized debt issuance costs	—	3,762
Depreciation, depletion and amortization	26,223	23,697
Cash distributions from unconsolidated affiliates	750	4,710
Minority interest	(12)	33
Net cash payment received from El Paso Corporation	1,960	2,040
Net income	$ 55,566	$ 42,215

Natural Gas Pipelines and Plants

	Quarter Ended March 31, 2004	Quarter Ended March 31, 2003
	(In thousands, except for volumes)	
Natural gas pipelines and plants revenue	$181,536	$197,227
Cost of natural gas and other products	(63,946)	(89,796)
Natural gas pipelines and plants margin	117,590	107,431
Operating expenses excluding depreciation, depletion, and amortization	(36,414)	(30,552)
Other income and cash distributions from unconsolidated affiliates in excess of earnings[(1)]	837	923
Minority interest	—	33
Performance cash flows	$ 82,013	$ 77,835
Volumes (MDth/d)		
Texas Intrastate	3,209	3,352
San Juan Gathering	1,247	1,130
Permian Basin Gathering	295	320
HIOS	743	751
Falcon Nest Pipeline[(2)]	272	30
Viosca Knoll Gathering	640	688
Other natural gas pipelines	520	518
Processing plants	721	810
Total volumes	7,647	7,599

(1) Earnings from unconsolidated affiliates for the quarters ended March 31, 2004 and 2003, were $534 thousand and $629 thousand.

(2) The Falcon Nest pipeline was placed in service in March 2003.

We provide natural gas gathering and transportation services for a fee. Agreements with some customers of our pipelines require that we purchase natural gas from them at the wellhead for an index price less an amount that compensates us for gathering services after which we sell the natural gas into the open market at points on our system at the same index price. Accordingly, under these agreements, our operating revenues and costs of natural gas and other products are impacted equally by changes in energy commodity prices, thus our margin for these agreements reflects only the fee we received for gathering services. At our Indian Basin processing facility, our revenues reflect the gross sales of NGL we retain as a processing fee. Included in our cost of natural gas and other products is the payment to the producers for the natural gas liquids we marketed on their behalf. For these reasons, we feel that gross margin (revenue less cost of natural gas and other products) provides a more accurate and meaningful basis for analyzing operating results for this segment. Revenues at our Chaco processing facility are representative of our processing fee.

During the latter half of 2002, we experienced a significant unfavorable variance between the fuel usage on HIOS and the fuel collected from our customers for our use. We believe a series of events may have contributed to this variance, including two major storms that hit the Gulf Coast region (and these assets) in late September and early October of 2002. As of March 31, 2004, we had recorded fuel differences of approximately $7.3 million, which is included in other non-current assets. We are currently in discussions with the FERC as well as our customers regarding the potential collection of some or all of the fuel differences. At this time we are not able to determine what amount, if any, may be collectible from our customers. Any amount we are unable to resolve or collect from our customers will negatively impact the future results of our natural gas pipelines and plants segment.

Quarter Ended March 31, 2004 Compared With Quarter Ended March 31, 2003

Natural gas pipelines and plants margin for the quarter ended March 31, 2004, was $10.2 million higher than in the same period in 2003. This increase was primarily due to an $11.6 million increase in margin for our Texas intrastate pipeline system, of which $5.5 million was attributable to the revaluation of our natural gas imbalances, due to a lower imbalance position in 2004. In addition, our Texas intrastate pipeline system had a $2.1 million increase in the base business in the first quarter of 2004 and an additional $4.1 million increase associated with improved efficiencies on the pipeline system over the same period in 2003. Margin also increased by $1.8 million reflecting a full quarter of results from the Falcon Nest Pipeline, which went into service in March 2003. Partially offsetting these increases was a $2.4 million decrease in margin at our Permian Basin gathering assets attributable to increased fuel costs and an additional $1.4 million decrease in margin related to lower volumes at our Indian Basin gas plant associated with colder temperatures.

Operating expenses excluding depreciation, depletion and amortization for the quarter ended March 31, 2004, were $5.9 million higher than the same period in 2003 primarily due to timing considerations associated with our normal recurring operating expenses and increased allocated administrative costs, primarily merger related costs and directors and officers liability insurance.

Oil and NGL Logistics

	Quarter Ended March 31,	
	2004	**2003**
	(In thousands, except for volumes)	
Oil and NGL logistics revenues	$ 15,188	$ 11,968
Cost of natural gas and other products	(960)	—
Oil and NGL logistics margin	14,228	11,968
Operating expenses excluding depreciation, depletion, and amortization	(6,762)	(4,330)
Other income and cash distributions from unconsolidated affiliates in excess of earnings[1]	2	3,962
Performance cash flows	$ 7,468	$ 11,600
Liquid Volumes (Bbls/d)		
NGL Fractionation Plants	76,143	67,036
NGL Pipeline Systems	27,476	18,958
Allegheny Oil Pipeline	29,195	17,491
Typhoon Oil Pipeline	33,354	18,517
Unconsolidated affiliate		
Poseidon Oil Pipeline[2]	101,581	153,798
Total liquid volumes	267,749	275,800

(1) Earnings from unconsolidated affiliates for the quarters ended March 31, 2004 and 2003, were $1,790 thousand and $2,687 thousand.

(2) Represents 100 percent of Poseidon volumes.

The majority of the earnings from the oil and NGL logistics segment are generated from volume-based fees for providing transportation of oil and NGL and fractionation of NGL. However, many of the agreements with the customers on our oil pipelines require that we purchase oil from the customer at the inlet of our pipeline for an index price, less an amount that compensates us for transportation services, and resell the oil to the customer at the outlet of our pipeline at the same index price. We record these transactions based on the net amount billed to our customers resulting in these transactions reflecting a fee for transportation services. For these reasons, we feel that gross margin (revenue less cost of natural gas and other products) provides a more accurate and meaningful basis for analyzing operating results for this segment.

Margin is driven by product pricing for both oil and NGLs and volumes. Both oil and NGLs volumes are impacted by natural resource decline as well as increases in new production. Volumes at our NGL fractionation plants are significantly impacted by processing economics, which are driven by the difference between natural gas prices and NGL prices.

Typhoon Oil Pipeline, a wholly owned subsidiary, has transportation agreements with BHP and ChevronTexaco which provide that Typhoon Oil purchase the oil produced at the inlet of its pipeline for an index price less an amount that compensates Typhoon Oil for transportation services. At the outlet of its pipeline, Typhoon Oil resells this oil back to these producers at the same index price. As disclosed in our 2003 Annual Report on Form 10-K, as amended, we now record revenue from these buy/sell transactions upon delivery of the oil based on the net amount billed to the producers. For the quarter ended March 31, 2003, we reduced by $48.8 million our revenues and cost of natural gas and other products to conform to the current period presentation. This revision had no effect on operating income, net income or partners' capital.

Quarter Ended March 31, 2004 Compared With Quarter Ended March 31, 2003

For the quarter ended March 31, 2004, margin was $2.3 million higher than the same period in 2003. Margin attributable to our NGL pipeline systems was up $1.4 million due to a 45 percent increase in volumes largely attributable to our NGL pipeline being down for maintenance through the third quarter of 2003. In addition, margin from our NGL fractionation plants increased $0.8 million due to higher volumes resulting from improved processing economics at the plants in 2004.

Operating expenses excluding depreciation, depletion and amortization for the quarter ended March 31, 2004, were $2.4 million higher than the same period in 2003 primarily due to timing considerations associated with our normal recurring operating expenses and increased allocated administrative costs, primarily merger related costs and directors and officers liability insurance.

Other income and cash distributions from unconsolidated affiliates in excess of earnings for the quarter ended March 31, 2004, declined $4.0 million. In October 2003, Poseidon began withholding distributions to fund its capital expenditures related to its Front Runner project. As a result, we did not receive cash distributions from Poseidon during the quarter ended March 31, 2004, and we do not expect to receive any distributions from Poseidon until the Front Runner project is complete.

Natural Gas Storage

	Quarter Ended March 31, 2004	Quarter Ended March 31, 2003
	(In thousands, except for volumes)	
Natural gas storage revenue	$12,450	$11,698
Cost of natural gas	207	(1,561)
Natural gas storage margin	12,657	10,137
Operating expenses excluding depreciation, depletion, and amortization	(3,597)	(3,136)
Other income and cash distributions from unconsolidated affiliates in excess of earnings	13	—
Minority interest	(12)	—
Performance cash flows	$ 9,061	$ 7,001
Firm storage (Bcf)		
Average working gas capacity available	13.5	13.5
Average firm subscription	13.0	12.7
Average monthly commodity volumes[1]	6.2	4.9
Interruptible storage (Bcf)		
Contracted volumes	0.2	—
Average monthly commodity volumes[1]	0.7	0.7

[1] Combined injections and withdrawals volumes.

At our Petal and Hattiesburg natural gas storage facilities, we collect fixed and variable fees for providing storage services, some of which is generated from customers who have cashout provisions, calculated by reference to a tariff-based index. We incur expenses, which are reflected as cost of natural gas, as we maintain these volumetric imbalance receivables and payables, all of which are valued at current gas prices. Cost of natural gas reflects the initial imbalance and the monthly revaluation of these amounts based on the monthly change in natural gas prices. For these reasons, we believe that gross margin (revenue less cost of natural gas and other products) provides a more accurate and meaningful basis for analyzing operating results for this segment.

Quarter Ended March 31, 2004 Compared with Quarter Ended March 31, 2003

For the quarter ended March 31, 2004, margin was $2.5 million higher than the same period in 2003 primarily due to a $1.6 million increase in margin at our Hattiesburg storage facility attributable to the impact that lower natural gas prices in 2004 had on the revaluation of our gas storage imbalances. In addition, margin was up an additional $0.9 million as a result of an increase in interruptible storage services at our leased Wilson storage facility. Operating expenses were flat period over period with no significant changes in the components of operating expenses.

Platform Services

	Quarter Ended March 31,	
	2004	**2003**
	(In thousands, except for volumes)	
Platform services revenue from external customers	$6,642	$4,382
Platform services intersegment revenue	585	646
Operating expenses excluding depreciation, depletion, and amortization	(863)	(793)
Other income and cash distributions from unconsolidated affiliates in excess of earnings	(1)	—
Performance cash flows	$6,363	$4,235
Natural gas platform volumes (MDth/d)		
East Cameron 373	111	120
Garden Banks 72	5	27
Viosca Knoll 817	5	6
Falcon Nest platform[1]	264	30
Total natural gas platform volumes	385	183
Oil platform volumes (Bbl/d)		
East Cameron 373	1,312	821
Garden Banks 72	826	1,031
Viosca Knoll 817	2,133	1,990
Falcon Nest platform[1]	808	121
Total oil platform volumes	5,079	3,963

(1) The Falcon Nest platform was placed in service in March 2003.

Our platform services segment generally earns revenue through demand fees (regular payments made by customers using our platform services regardless of volumes) and commodity charges (volume-based payments made by customers). Contracts for platform services often include both demand fees and commodity charges, but demand fees generally expire after a fixed period of time.

Quarter Ended March 31, 2004 Compared with Quarter Ended March 31, 2003

For the quarter ended March 31, 2004, performance cash flows were $2.1 million higher than in the same period in 2003. Revenues increased by $3.2 million due to a full quarter of results attributable to the Falcon Nest fixed leg platform, which was placed in service in March 2003. This increase is partially offset by lower revenues of $1.4 million from the East Cameron 373 platform resulting from lower demand fees. Operating expenses were flat period over period with no significant changes in the components of operating expenses.

Marco Polo TLP

The Marco Polo TLP, which is owned by Deepwater Gateway L.L.C., our 50 percent owned joint venture with Cal Dive International, was installed in the first quarter of 2004. First production and, thus, volumetric payments are expected to begin in mid-2004. In April 2004, Deepwater Gateway began receiving monthly demand revenues of $2.1 million.

In March 2004, Deepwater Gateway L.L.C. executed a binding memorandum of understanding with Eni Petroleum Exploration Co. Inc, ConocoPhillips Company and Union Oil Company of California for the processing of their 48 percent working interest in the K2 Field production on the Marco Polo TLP. Anadarko's 52 percent interest in the K2 Field was previously dedicated.

Other, Non-Segment Results

Our oil and natural gas production interests in the Garden Banks 72, Garden Banks 117, Viosca Knoll 817 and West Delta 35 Blocks principally comprise the non-segment activity. Production from these properties, except West Delta 35, is gathered, transported, and processed through our pipeline systems and platform facilities. Oil and natural gas production volumes are produced and sold to various third parties at the market price. Revenue is recognized in the period of production, all of which is sold to our customers. These revenues may be impacted by market changes, hedging activities, and natural declines in production reserves. We are reducing our oil and natural gas production activities by not acquiring additional properties due to their higher risk profile. Accordingly, our focus is to maximize the production from our existing portfolio of oil and natural gas properties.

Also included in other, non-segment results are the quarterly payments we received from El Paso Corporation in connection with the sale of our Gulf of Mexico assets in January 2001. El Paso Corporation agreed to pay us $2.25 million per quarter through the fourth quarter of 2003 and $2 million in the first quarter of 2004. As of March 31, 2004, all required payments had been received and, as a result, future performance cash flows for other non-segment activities will be lower compared to prior periods.

Depreciation, Depletion, and Amortization

Depreciation, depletion and amortization for the quarter ended March 31, 2004, was $2.5 million higher than the same period in 2003 primarily due to an increase in depreciation expense of $1.2 million from assets placed in service during 2003, primarily our communication assets placed in service in October 2003, Falcon Nest pipeline and platform placed in service in March 2003 and the Viosca Knoll pipeline extension placed in service in December 2003, partially offset by a decrease in depreciation expense of $0.5 million due to our revised estimate for the depreciable life of the Chaco plant resulting from our exchange transaction with El Paso Corporation in October 2003. Additionally, we had increased depletion of $0.8 million resulting from the true-up of reserves based on revised reserve estimates.

Interest and Debt Expense

Interest and debt expense, net of capitalized interest, for the quarter ended March 31, 2004, was approximately $6.5 million lower than the same period in 2003. The decrease is primarily due to a lower weighted average outstanding balance on our revolving credit facility and lower weighted average interest rates on our revolving credit facility and senior secured term loan. Additionally, interest and debt expense decreased as a result of the repayment of our senior secured acquisition term loan during the first quarter of 2003, the repayment of the GulfTerra Holding term loan during the third quarter of 2003 and the redemption of a portion of our senior subordinated notes in December 2003.

Capitalized interest for the quarter ended March 31, 2004, was $3.7 million, representing an increase of $1.8 million from the quarter ended March 31, 2003. The increase is the result of higher expenditures related to our construction projects, primarily the Marco Polo natural gas and oil pipelines and the Phoenix gathering system.

Loss Due to Write-Off of Unamortized Debt Issuance Costs

In March 2003, we repaid our $237.5 million senior secured acquisition term loan which was due in May 2004 and recognized a loss of $3.8 million related to the write-off of unamortized debt issuance costs related to this loan.

Cumulative Effect of Accounting Change

Our cumulative effect of accounting change for the quarter ended March 31, 2003, reflects our adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations,* on January 1, 2003.

Commitments and Contingencies

See Item 1, Financial Statements, Note 9, which is incorporated herein by reference.

New Accounting Pronouncements Not Yet Adopted

None.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

We have made statements in this document that constitute forward-looking statements. These statements are subject to risks and uncertainties. Forward-looking statements include information concerning possible or assumed future results of operations. These statements may relate to information or assumptions about:

- earnings per unit;
- capital and other expenditures;
- cash distributions;
- financing plans;
- capital structure;
- liquidity and cash flow;
- pending legal proceedings and claims, including environmental matters;
- future economic performance;
- operating income;
- cost savings;
- management's plans; and
- goals and objectives for future operations.

Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements are described in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2003, and our other filings with the SEC. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and made in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we express an expectation or belief as to future results, such expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. These statements relate to analyses and other information which are based on forecasts of future results and estimates of amounts not yet determinable. These statements also relate to our future prospects, developments and business strategies. These forward-looking statements are identified by their use of terms and phrases such as "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "predict," "project," "will," and similar terms and phrases, including references to assumptions. These forward-looking statements involve risks and uncertainties that may cause our actual future activities and results of operations to be materially different from those suggested or described.

These risks may also be specifically described in our Current Reports on Form 8-K and other documents filed with the SEC. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information or otherwise. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those expected, estimated or projected.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, our quantitative and qualitative disclosures about market risks reported in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2003, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

A majority of our commodity purchases and sales, which relate to sales of oil and natural gas associated with our production operations, purchases and sales of natural gas associated with pipeline operations, sales of natural gas liquids and purchases or sales of gas associated with our processing plants and our gathering activities, are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities.

We estimate the entire $13.3 million of unrealized losses included in accumulated other comprehensive income at March 31, 2004, will be reclassified from accumulated other comprehensive income as a reduction to earnings over the next nine months. When our derivative financial instruments are settled, the related amount in accumulated other comprehensive income is recorded in the income statement in operating revenues, cost of natural gas and other products, or interest and debt expense, depending on the item being hedged. The effect of reclassifying these amounts to the income statement line items is recording our earnings for the period related to the hedged items at the "hedged price" under the derivative financial instruments.

In February and August 2003, we entered into derivative financial instruments to continue to hedge our exposure during 2004 to changes in natural gas prices relating to gathering activities in the San Juan Basin. The derivatives are financial swaps on 30,000 MMBtu per day whereby we receive an average fixed price of $4.23 per MMBtu and pay a floating price based on the San Juan index. As of March 31, 2004, the fair value of these cash flow hedges was a liability of $9.2 million, as the market price at that date was higher than the hedge price. For the quarter ended March 31, 2004, we reclassified approximately $1.7 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income as a decrease in revenue. No ineffectiveness exists in this hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

During 2003, we entered into additional derivative financial instruments to hedge a portion of our business' exposure to changes in NGL prices during 2004. We entered into financial swaps for 6,000 barrels per day for the period from August 2003 to September 2004. The average fixed price received is $0.47 per gallon for 2004 while we pay a monthly average floating price based on the OPIS average price for each month. As of March 31, 2004, the fair value of these cash flow hedges was a liability of $4.1 million. For the quarter ended March 31, 2004, we reclassified approximately $2.1 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income to earnings. No ineffectiveness exists in this hedging relationship because all purchase and sales prices are based on the same index and volumes as the hedge transaction.

In connection with our GulfTerra Intrastate Alabama operations, we have fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We entered into cash flow hedges in 2003 to offset the risk of increasing natural gas prices. For January and February 2004, we contracted to purchase 20,000 MMBtu and for March 2004, we contracted to purchase 15,000 MMBtu. The average fixed price paid during 2004 was $5.28 per MMBtu while we received a floating price based on the SONAT-Louisiana index. As of March 31, 2004, these cash flow hedges expired and we reclassified a gain of approximately $45 thousand from accumulated other comprehensive income to earnings. No ineffectiveness existed in this hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million of our $8\frac{1}{2}$% senior subordinated notes due 2011. With this swap agreement, we paid the counterparty a LIBOR based interest rate plus a spread of 4.20% and received a fixed rate of $8\frac{1}{2}$%. We accounted for this derivative as a fair value hedge under SFAS No. 133. In March 2004, we terminated our fixed to floating interest rate swap with our counterparty. The value of the transaction at termination was zero, and as such, neither we, nor our counterparty, were required to make any payments. Also, neither we, nor our counterparty, have any future obligations under this transaction.

Item 4. Controls and Procedures

Evaluation of Controls and Procedures. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (Disclosure Controls) and internal controls over financial reporting (Internal Controls) as of the end of the period covered by this Quarterly Report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (Exchange Act).

Definition of Disclosure Controls and Internal Controls. Disclosure Controls are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified under the Exchange Act. Disclosure Controls include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Internal Controls are procedures which are designed with the objective of providing reasonable assurance that (1) our transactions are properly authorized; (2) our assets are safeguarded against unauthorized or improper use; and (3) our transactions are properly recorded and reported, all to permit the preparation of our financial statements in conformity with generally accepted accounting principles.

Limitations on the Effectiveness of Controls. Our management, including the principal executive officer and principal financial officer, does not expect that our Disclosure Controls and Internal Controls 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. Because of 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 Internal Controls are designed to provide such reasonable assurances of achieving our desired control objectives, and our principal executive officer and principal financial officer have concluded that our Disclosure Controls and Internal Controls are effective in achieving that level of reasonable assurance.

No Significant Changes in Internal Controls. We have sought to determine whether there were any "significant deficiencies" or "material weaknesses" in our Internal Controls, or whether we had identified any acts of fraud involving personnel who have a significant role in our Internal Controls. This information was important both for the controls evaluation generally and because the principal executive officer and principal financial officer are required to disclose that information to the Audit and Conflicts Committee of our general partner's board of directors and our independent auditors and to report on related matters in this section of the Quarterly Report. The principal executive officer and principal financial officer note that there have not been any significant changes in Internal Controls or in other factors that could significantly affect Internal Controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

We are currently undergoing a comprehensive effort to ensure compliance with Section 404 of the Sarbanes Oxley Act of 2002 for the year ended December 31, 2004. This effort includes internal control documentation and review under the direction of senior management. During the course of these activities, we have identified certain internal control issues which management believes need to be improved. These control issues are, in large part, the result of our increased size and complexity as a result of acquisitions and continued business growth.

The review has not identified any significant deficiencies or material weaknesses in internal control as defined by the Public Company Accounting and Oversight Board. However, we have made improvements to our internal controls over financial reporting as a result of our review efforts and will continue to do so. These improvements include formalizing and communicating certain policies and procedures, strengthening system security access and segregation of duties, and increasing the frequency of monitoring controls.

Effectiveness of Disclosure Controls. Based on the controls evaluation, our principal executive officer and principal financial officer have concluded that the Disclosure Controls are effective to ensure that material information relating to us and our consolidated subsidiaries is made known to our management, including the principal executive officer and principal financial officer, on a timely basis.

Officer Certifications. The certifications from the principal executive officer and principal financial officer required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as Exhibits to this Quarterly Report.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 9, which is incorporated herein by reference.

Item 2. Changes in Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

Each exhibit identified below is filed as part of this document. Exhibits not incorporated by reference to a prior filing are designated by a "*"; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" represent a management contract or compensatory plan or arrangement.

Exhibit Number		Description
2.A	—	Merger Agreement, dated as of December 15, 2003, by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Company, L.L.C., Enterprise Products Partners, L.P., Enterprise Products GP, LLC, and Enterprise Products Management LLC (Exhibit 2.1 to our Current Report on Form 8-K filed December 15, 2003).
3.A	—	Amended and Restated Certificate of Limited Partnership dated February 14, 2002; Amendment dated April 30, 2003 (Exhibit 3.A.1 to our 2003 First Quarter Form 10-Q); Amendment 2 dated July 25, 2003 (Exhibit 3.A.1 to our 2003 Second Quarter Form 10-Q).
3.A.1	—	Conformed Certificate of Limited Partnership (Exhibit 3.A.1 to our 2003 Third Quarter Form 10-Q).
3.B	—	Second Amended and Restated Agreement of Limited Partnership effective as of August 31, 2000 (Exhibit 3.B to our Current Report on Form 8-K dated March 6, 2001); First Amendment dated November 27, 2002 (Exhibit 3.B.1 to our Current Report on Form 8-K dated December 11, 2002); Second Amendment dated May 5, 2003 (Exhibit 3.B.2 to our Current Report on Form 8-K dated May 13, 2003); Third Amendment dated May 16, 2003 (Exhibit 3.B.3 to our Current Report on 8-K dated May 16, 2003); Fourth Amendment dated July 23, 2003 (Exhibit 3.B.1 to our 2003 Second Quarter Form 10-Q); Fifth Amendment dated August 21, 2003 (Exhibit 3.B.1 to our Current Report on Form 8-K dated October 10, 2003).
3.B.1	—	Conformed Partnership Agreement (Exhibit 3.B.2 to our Current Report on Form 8-K dated October 10, 2003).

Exhibit Number	Description
4.D	— Indenture dated as of May 27, 1999 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors and Chase Bank of Texas, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4, filed on June 24, 1999, File Nos. 333-81143 through 333-81143-17); First Supplemental Indenture dated as of June 30, 1999 (Exhibit 4.2 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999 File Nos. 333-81143 through 333-81143-17); Second Supplemental Indenture dated as of July 27, 1999 (Exhibit 4.3 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999, File Nos. 333-81143 through 333-81143-17); Third Supplemental Indenture dated as of March 21, 2000, to the Indenture dated as of May 27, 1999, (Exhibit 4.7.1 to our 2000 Second Quarter Form 10-Q); Fourth Supplemental Indenture dated as of July 11, 2000 (Exhibit 4.2.1 to our 2001 Third Quarter Form 10-Q); Fifth Supplemental Indenture dated as of August 30, 2000 (Exhibit 4.2.2 to our 2001 Third Quarter Form 10-Q); Sixth Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.D.1 to our 2002 First Quarter Form 10-Q); Seventh Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.D.2 to our 2002 First Quarter Form 10-Q); Eighth Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.D.3 to our 2002 Third Quarter Form 10-Q); Ninth Supplemental Indenture dated as of November 27, 2002 (Exhibit 4.D.1 to our Current Report on Form 8-K dated March 19, 2003); Tenth Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.D.2 to our Current Report on Form 8-K dated March 19, 2003); Eleventh Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.D.1 to our 2003 Second Quarter Form 10-Q).
4.E	— 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 (Exhibit 4.1 to our 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 (Exhibit 4.E.1 to our 2002 First Quarter Form 10-Q), Second Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.2 to our 2002 First Quarter Form 10-Q); Third Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.E.3 to our 2002 Third Quarter Form 10-Q); Fourth Supplemental Indenture dated as of November 27, 2002 (Exhibit 4.E.1 to our Current Report on Form 8-K dated March 19, 2003); Fifth Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.E.2 to our Current Report on Form 8-K dated March 19, 2003); Sixth Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.E.1 to our 2003 Second Quarter Form 10-Q).
4.G	— Registration Rights Agreement by and between El Paso Corporation and GulfTerra Energy Partners, L.P. dated as of November 27, 2002 (Exhibit 4.G to our Current Report on Form 8-K dated December 11, 2002).
4.I	— 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 (Exhibit 4.I to our Current Report on Form 8-K dated December 11, 2002); First Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.I.1 to our Current Report on Form 8-K dated March 19, 2003). Second Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.I.1 to our 2003 Second Quarter Form 10-Q).

Exhibit Number	Description
4.K	— 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 (Exhibit 4.K to our Quarterly Report on Form 10-Q dated May 15, 2003), First Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.K.1 to our 2003 Second Quarter Form 10-Q).
4.L	— 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 (Exhibit 4.L to our 2003 Second Quarter Form 10-Q).
4.M	— Unitholder Agreement dated May 16, 2003 by and between GulfTerra Energy Partners, L.P. and Fletcher International, Inc. (Exhibit 4.L to our Current Report on Form 8-K filed May 19, 2003).
4.N	— Exchange and Registration Rights Agreement by and among GulfTerra Energy Company, L.L.C., GulfTerra Energy Partners, L.P. and Goldman Sachs & Co. dated as of October 2, 2003 (Exhibit 10.U to our Current Report on Form 8-K dated October 10, 2003).
*31.A	— Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.B	— Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.A	— Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.B	— Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Undertaking

We hereby undertake, pursuant to Regulation S-K Items 601(b), paragraph (4)(iii), to furnish to the U.S. Securities and Exchange Commission, upon request, all constituent instruments defining the rights of holders of our long-term debt not filed herewith for the reason that the total amount of securities authorized under any such instruments does not exceed 10 percent of our total consolidated assets.

(b) Reports on Form 8-K

We filed a Current Report on Form 8-K dated February 3, 2004 to announce an overview of our merger with Enterprise.

We filed a Current Report on Form 8-K dated February 11, 2004 to announce William G. Manias has assumed the position of Chief Financial Officer.

We filed a Current Report on Form 8-K dated April 20, 2004 to announce Enterprise and El Paso Corporation amended their agreement with regard to their ownership of the merged companies' general partner upon completion of the merger.

We filed a Current Report on Form 8-K dated May 5, 2004 to notify our unitholders and the market that we have identified a potential revision to the accounting for the cash settlement of natural gas imbalance receivables on our Texas Intrastate pipeline system, which we acquired in April 2002.

We filed a Current Report on Form 8-K dated May 7, 2004 to file the one year audited balance sheet of GulfTerra Energy Company, L.L.C. our general partner, as of December 31, 2003, which is incorporated by reference into our Registration Statement on Form S-3 (No. 333-81772, No. 333-85987, No. 333-107082 and No. 333-110116) and on Form S-8 (No. 333-70617).

We also furnished to the SEC Current Reports on Form 8-K under Item 9 and Item 12. Current Reports on Form 8-K under Item 9 and Item 12 are not considered to be "filed" for purposes of Section 18 of the Securities and Exchange Act of 1934 and are not subject to the liabilities of that section.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GULFTERRA ENERGY PARTNERS, L.P.

Date: May 10, 2004

By: /s/ WILLIAM G. MANIAS

William G. Manias
Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: May 10, 2004

By: /s/ KATHY A. WELCH

Kathy A. Welch
Vice President and Controller
(Principal Accounting Officer)