UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

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

Date of report (Date of earliest event reported): June 30, 2004

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**1-14323**	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

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

(713) 880-6500
(Registrant’s Telephone Number, including Area Code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. OTHER EVENTS.

On December 15, 2003, Enterprise Products Partners L.P. (“Enterprise”) and certain of its affiliates, El Paso Corporation (“El Paso”) and certain of its affiliates and GulfTerra Energy Partners, L.P. (“GulfTerra”) and certain of its affiliates entered into a series of definitive agreements pursuant to which Enterprise and GulfTerra will merge. The purpose of this Current Report on Form 8-K is to file the following unaudited consolidated financial statements of GulfTerra for the quarters and six months ended June 30, 2004 and 2003. Enterprise is filing these financial statements with this Current Report so that they will be incorporated by reference in its currently effective registration statements.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

For the Quarters and Six Months Ended June 30, 2004 and 2003
(Unaudited)

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except per unit amounts)
(Unaudited)

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003(1)	2004	2003(1)
Operating revenues	$225,218	$237,031	$445,557	$467,126
Operating expenses				
Cost of natural gas and other products	60,095	85,385	124,522	176,138
Operation and maintenance	51,967	48,551	100,463	89,195
Depreciation, depletion and amortization	26,080	24,846	52,303	48,543
(Gain) loss on sale of long-lived assets	—	363	(24)	257
	138,142	159,145	277,264	314,133
Operating income	87,076	77,886	168,293	152,993
Earnings from unconsolidated affiliates	3,258	2,987	5,466	6,303
Minority interest income (expense)	—	(47)	12	(80)
Other income	124	309	284	692
Interest and debt expense	26,696	31,838	54,727	66,324
Loss due to early redemptions of debt	16,285	—	16,285	3,762
Income before cumulative effect of accounting change	47,477	49,297	103,043	89,822
Cumulative effect of accounting change	—	—	—	1,690
Net income	$ 47,477	$ 49,297	$103,043	$ 91,512
Income allocation				
Series B unitholders	$ —	$ 3,898	$ —	$ 7,774
General partner				
Income before cumulative effect of accounting change	$ 21,420	$ 15,856	$ 42,549	$ 30,716
Cumulative effect of accounting change	—	—	—	17
	$ 21,420	$ 15,856	$ 42,549	$ 30,733
Common unitholders				
Income before cumulative effect of accounting change	$ 22,022	$ 24,160	$ 51,087	$ 41,614
Cumulative effect of accounting change	—	—	—	1,340
	$ 22,022	$ 24,160	$ 51,087	$ 42,954
Series C unitholders				
Income before cumulative effect of accounting change	$ 4,035	$ 5,383	$ 9,407	$ 9,718
Cumulative effect of accounting change	—	—	—	333
	$ 4,035	$ 5,383	$ 9,407	$ 10,051
Basic and diluted earnings per common unit				
Income before cumulative effect of accounting change	$ 0.37	$ 0.50	$ 0.86	$ 0.90
Cumulative effect of accounting change	—	—	—	0.03
Net income	$ 0.37	$ 0.50	$ 0.86	$ 0.93
Basic weighted average number of common units outstanding	59,649	48,005	59,298	46,024
Diluted weighted average number of common units outstanding	59,886	48,476	59,566	46,302
Distributions declared per common unit	$ 0.710	$ 0.675	$ 1.420	$ 1.350

(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)

	June 30, 2004	December 31, 2003
ASSETS		
Current assets		
Cash and cash equivalents	$ 33,445	$ 30,425
Accounts receivable, net	161,414	154,235
Affiliated note receivable	3,713	3,768
Other current assets	21,670	20,595
Total current assets	220,242	209,023
Property, plant, and equipment, net	2,930,005	2,894,492
Intangible assets	3,177	3,401
Investments in unconsolidated affiliates	203,303	175,747
Other noncurrent assets	29,354	38,917
Total assets	$3,386,081	$3,321,580
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable	$ 148,919	$ 168,133
Accrued interest	8,083	11,199
Current maturities of senior secured term loans	5,000	3,000
Other current liabilities	41,328	27,035
Total current liabilities	203,330	209,367
Revolving credit facility	462,000	382,000
Senior secured term loans, less current maturities	493,500	297,000
Long-term debt	923,016	1,129,807
Other noncurrent liabilities	42,089	49,043
Total liabilities	2,123,935	2,067,217
Commitments and contingencies		
Minority interest	1,801	1,777
Partners' capital		
Limited partners		
Common units; 59,698,129 and 58,404,649 units issued and outstanding	912,236	898,072
Series C units; 10,937,500 units issued and outstanding	334,892	341,350
General partner	13,217	13,164
Total partners' capital	1,260,345	1,252,586
Total liabilities and partners' capital	$3,386,081	$3,321,580

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

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

	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
Cash flows from operating activities		
Net income	$ 103,043	$ 91,512
Less cumulative effect of accounting change	—	1,690
Income before cumulative effect of accounting change	103,043	89,822
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	52,303	48,543
Distributed earnings of unconsolidated affiliates		
Earnings from unconsolidated affiliates	(5,466)	(6,303)
Distributions from unconsolidated affiliates	1,450	8,230
(Gain) loss on sale of long-lived assets	(24)	257
Loss due to write-off of unamortized debt issuance costs	3,884	3,762
Amortization of debt issuance costs, premiums and discounts	2,651	4,016
Other noncash items	6,352	1,341
Working capital changes, net of acquisitions and noncash transactions	(27,961)	(15,502)
Net cash provided by operating activities	136,232	134,166
Cash flows from investing activities		
Additions to property, plant and equipment	(86,107)	(207,011)
Proceeds from sale and retirement of assets	197	3,215
Additions to investments in unconsolidated affiliates	(17,947)	(197)
Net cash used in investing activities	(103,857)	(203,993)
Cash flows from financing activities		
Net proceeds from revolving credit facility	386,932	223,000
Repayments of revolving credit facility	(307,000)	(298,854)
Net proceeds from senior secured term loan	199,651	—
Repayment of senior secured term loan	(1,500)	(2,500)
Repayment of senior secured acquisition term loan	—	(237,500)
Net proceeds from (debt issuance costs for) issuance of long-term debt	(52)	292,479
Repayments of long-term debt	(214,085)	—
Net proceeds from issuance of common units, Series F convertible units and conversion of Series F convertible units	48,536	182,182
Distributions to partners	(142,317)	(107,427)
Contribution from general partner	480	1
Net cash (used in) provided by financing activities	(29,355)	51,381
Increase (decrease) in cash and cash equivalents	3,020	(18,446)
Cash and cash equivalents at beginning of period	30,425	36,099
Cash and cash equivalents at end of period	$ 33,445	$ 17,653
Schedule of noncash financing activities:		
Redemption of Series B preference units contributed from our general partner	$ —	$ 1,788

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 June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Net income	$47,477	$49,297	$103,043	$91,512
Other comprehensive income (loss)	2,127	272	(2,172)	(5,443)
Total comprehensive income	$49,604	$49,569	$100,871	$86,069

Accumulated Other Comprehensive Loss

	June 30, 2004	December 31, 2003
Beginning balance	$ (9,027)	$ (5,622)
Unrealized mark-to-market losses on cash flow hedges arising during period	(10,716)	(12,924)
Reclassification adjustments for changes in initial value of derivative instruments to settlement date	8,544	10,018
Accumulated other comprehensive loss from investment in unconsolidated affiliate	—	(499)
Ending balance	$(11,199)	$ (9,027)
Accumulated other comprehensive loss allocated to:		
Common units' interest	$ (9,305)	$ (7,488)
Series C units' interest	$ (1,742)	$ (1,409)
General partner's interests	$ (152)	$ (130)

See accompanying notes.

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 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. References to “us”, “we”, “our”, or “GulfTerra” are intended to mean the consolidated business and operations of GulfTerra Energy Partners, L.P.

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 June 30, 2004, and for the quarters and six months ended June 30, 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 June 30, 2004 and December 31, 2003, we had included in accounts receivable, net on our balance sheets, unbilled trade receivables of $74.6 million and $63.1 million. Also, as of June 30, 2004 and December 31, 2003, we had included in accounts payable on our balance sheets, accrued gas purchase costs of $20.0 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 June 30, 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 and six months ended June 30, 2003, we reduced by $73.1 million and $121.9 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 and six months ended June 30, 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. Compensation expense for the quarter and six months ended June 30, 2004 and 2003 is reflected in the table below for our stock-based compensation programs accounted for under the provisions of SFAS No. 123.

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 June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands, except per unit amounts)			
Net income as reported	$47,477	$49,297	$103,043	$91,512
Add: Stock-based employee compensation expense included in reported net income	133	366	267	679
Less: Stock-based employee compensation expense determined under fair value based method	(159)	(406)	(300)	(720)
Pro forma net income	$47,451	$49,257	$103,010	$91,471
Pro forma net income allocated to common unitholders	$21,996	$24,120	$ 51,054	$42,913
Earnings per common unit:				
Basic and diluted, as reported and pro forma	$ 0.37	$ 0.50	$ 0.86	$ 0.93

The effects of applying the provisions of SFAS No. 123 in this pro forma disclosure for all of our stock-based compensation programs 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.

Inventory

In June 2004, we purchased pipeline inventory, consisting of parts and materials, from El Paso Natural Gas Company (EPNG); see Note 8, Related Party Transactions, for further discussion. This inventory is included on our balance sheet as of June 30, 2004, in other current assets. We use the average cost method to account for our inventory and we value our inventory at the lower of its cost or market value.

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.

Two-Class Method of Computing Earnings per Common Unit

During the second quarter of 2004, we adopted the provisions of Emerging Issues Task Force (EITF) 03-6, *Participating Securities and the Two-Class Method under SFAS No. 128.* EITF 03-6 requires the use of the two-class method of determining basic earnings per unit. Under the two-class method, distributions to equity owners are subtracted from earnings, and any remaining earnings would be allocated to the various classes of owners in proportion to their right to receive distributions as if those earnings had been distributed. The total of distributions to each class of owner plus the amount allocated to each class would be used to compute earnings per unit for that class. Because our distributions to owners exceeded earnings during the periods presented, as has historically been the case, the two-class method did not produce any change in result from the way we have traditionally computed earnings per unit. As a result, the adoption of this standard had no effect on our earnings per unit calculation for the quarters and six months ended June 30, 2004 and 2003.

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; and

- 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.

On June 22, 2004, Enterprise’s registration statement on Form S-4 was declared effective by the SEC. On July 29, 2004, our common and Series C unitholders approved the adoption of the merger agreement to combine us with a wholly-owned subsidiary of Enterprise. See Part II, Other Information, Item 4. Submission of Matters to a Vote of Security Holders, for the results of the unitholder vote. We expect the completion of the merger to occur in the third quarter of 2004, although it remains subject to review by the Federal Trade Commission (FTC) and the satisfaction of other conditions to close.

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.* In March 2004, we recorded a liability and a related deferred charge of $4.3 million, which was 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 charge 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 and six months ended June 30, 2004, we amortized $2.2 million and $2.8 million to expense. As of June 30, 2004, the remaining deferred charge was $1.5 million. 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. During the quarter and six months ended June 30, 2004, we recognized expenses for legal and audit fees totaling $1.4 million and $1.5 million associated with 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. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

	June 30, 2004	December 31, 2003
	(In thousands)	
Property, plant and equipment, at cost[1]		
Pipelines	$2,526,336	$2,487,102
Platforms and facilities	164,212	121,105
Processing plants	305,904	305,904
Oil and natural gas properties	131,100	131,100
Storage facilities	338,735	337,535
Construction work-in-progress	386,875	383,640
	3,853,162	3,766,386
Less accumulated depreciation, depletion and amortization	923,157	871,894
Total property, plant and equipment, net	$2,930,005	$2,894,492

(1) Includes leasehold acquisition costs with an unamortized balance of $2.1 million and $3.2 million at June 30, 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.

4. 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. To avoid a default, our credit facility must be refinanced or amended at or before the closing of the merger. Enterprise has stated that it currently intends that our credit facility be refinanced before the closing of the merger and that, if that does not occur, there are reasonable grounds to believe that our existing credit facility will be amended prior to the closing of the merger. If the facility is not amended or refinanced prior to closing, the resulting default would have a material adverse effect on the combined company. In addition, the closing of the merger 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 closing. In coordination with Enterprise, we are evaluating alternative financing plans in preparation for the closing of the merger. On August 4, 2004, Enterprise announced that one of its subsidiaries commenced cash tender offers to purchase any and all of our outstanding senior subordinated and senior notes. In connection with the tender offers, Enterprise is soliciting consents to proposed amendments that would eliminate certain restrictive covenants and default provisions contained in the indentures governing the notes. Enterprise is commencing the tender offers and consent solicitations in anticipation of completing the merger, and the merger is a non-waivable condition to the completion of the tender offers and consent solicitations. We and Enterprise can agree on the date of the merger closing after the receipt of all necessary approvals. We do not intend to close until appropriate financing or other arrangements are in place.

Credit Facility

As of June 30, 2004, our credit facility consisted of three parts: the revolving credit facility maturing in 2006, a senior secured term loan maturing in 2007 and a senior secured term loan maturing in 2008. Our credit facility is guaranteed by us and each of our subsidiaries, excluding 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 Standard & Poor’s (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 June 30, 2004, we had $462 million outstanding under our revolving credit facility at an average interest rate of 3.16%. We may elect that all or a portion of the revolving credit facility bear interest at either the variable base rate described above increased by 1.0% or LIBOR increased by 2.0%. The amount available to us at June 30, 2004, under this facility was $218 million.

Senior Secured Term Loans

In May 2004, we obtained an additional $200 million senior secured term loan in addition to our already existing $300 million senior secured term loan. We initially used this additional $200 million to temporarily reduce indebtedness under our $700 million revolving credit facility and subsequently to fund the redemption of our $175 million aggregate principal amount of 10 3/8% senior subordinated notes due 2009. Our new senior secured term loan, which we may prepay in full at any time, is payable in semi-annual installments of $1.0 million in November and May of each year for the first six installments, and the remaining balance is due at maturity in October 2007. Our already-existing 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 is due at maturity in December 2008. On both senior secured term loans, we may elect that all or a portion of the senior secured term loans bear interest at either 1.25% over the variable base rate described above or LIBOR increased by 2.25%. As of June 30, 2004, we had $498.5 million outstanding on our senior secured term loans with an average interest rate of 3.65%.

Long-Term Debt

In April 2004, we redeemed, at a premium, approximately $39.1 million in principal amount of our 8 1/2% senior subordinated notes due June 2010. In connection with the redemption of the notes, we recognized additional expense during the quarter ended June 30, 2004, totaling $4.1 million resulting from the payment of the redemption premium and the write-off of unamortized debt issuance costs.

In June 2004, we redeemed all of our outstanding $175 million aggregate principal amount of 10 3/8% senior subordinated notes due 2009. The notes were redeemed at a redemption price of 105.2% of the principal amount, plus accrued and unpaid interest up to June 1, 2004. In connection with the redemption of the notes, we recognized additional expense during the quarter ended June 30, 2004, totaling $12.2 million resulting from the payment of the redemption premium and the write-off of unamortized debt issuance costs.

We accounted for the costs on both redemptions in accordance with the provisions of SFAS No. 145, *Rescission of Financial Accounting Standards Board (FASB) Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*.

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 more balanced 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 was 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 Development 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 million in Industrial Development Revenue Bonds to GulfTerra Field Services, L.L.C., our direct, wholly–owned subsidiary. 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. We have netted the loan amount and the bond amount of $52 million and the interest payable and interest receivable amount of $0.6 million on our balance sheet as of June 30, 2004. We have also netted the interest expense and interest income amount of $0.6 million on our income statements for the quarter and six months ended June 30, 2004. Our presentation of the Industrial Development Revenue Bonds is reflected in accordance with the provisions of FIN No. 39, *Offsetting of Amounts Related to Certain Contracts,* and SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,* since we have the ability and intent to offset these items.

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 June 30, 2004, Poseidon had $111 million outstanding with an average interest rate of 3.47%.

Poseidon's credit agreement contains covenants such as restrictions on debt levels, liens, mergers, the sales of assets and dividends 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, an unconsolidated affiliate in which we have a 50 percent joint venture interest and that constructed 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. Construction of the Marco Polo TLP was completed during the first quarter of 2004, and in June 2004, Deepwater Gateway converted the project finance loan into a term loan with a final maturity date of June 2009. The term loan is payable in twenty equal quarterly installments of $5.5 million beginning September 30, 2004, and the remaining outstanding principal of $45 million is due on the maturity date in June 2009. Interest rates are variable and the loan is collateralized by substantially all of Deepwater Gateway's assets. If Deepwater Gateway defaults on its payment obligations under the term loan, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of June 30, 2004, Deepwater Gateway had $155 million outstanding under the term loan at an average interest rate of 3.15% and had not paid us or any of our subsidiaries any distributions.

Cameron Highway

Cameron Highway Oil Pipeline Company (Cameron Highway), 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.

The construction loan bears interest at a variable rate. Upon completion of the construction, which is expected during the fourth quarter of 2004, 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 $8.1 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by January 2006, the construction loan and senior secured notes become fully due and payable. At June 30, 2004, Cameron Highway had $171 million outstanding under the construction loan at an average interest rate of 4.56%.

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 June 30, 2004, Cameron Highway had $100 million outstanding under the senior secured notes at an average interest rate of 7.36%.

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 June 30, 2004 (in thousands):

2004	$ 2,500
2005	5,000
2006	467,000
2007	198,000
2008	288,000
Thereafter	921,515
Total long-term debt and other financing obligations, including current maturities	$1,882,015

Loss Due to Early Redemptions of Debt

We recognized losses associated with early redemptions of debt as follows (in thousands):

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Loss due to payment of redemption premiums	$12,401	$ —	$12,401	$ —
Loss due to write-off of unamortized debt issuance costs	3,884	—	3,884	3,762
	$16,285	$ —	$16,285	$3,762

5. 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:

Six Months Ended June 30, 2004

(In thousands)

	Coyote	Deepwater Gateway(1)	Cameron Highway(2)	Poseidon	Total
End of period ownership interest	50%	50%	50%	36%	
Operating results data:					
Operating revenues	$3,600	$ 6,300	$ —	$18,116	
Other income	2	10	84	23	
Operating expenses	(296)	(63)	—	(2,602)	
Depreciation	(721)	(1,962)	—	(4,930)	
Other expenses	(341)	(1,485)	(382)	(1,827)	
Net income	$2,244	$ 2,800	$(298)	$ 8,780	
Our share:					
Allocated income (loss)	$1,122	$ 1,400	$(149)	$ 3,161	
Adjustments(3)	(4)	(191)	92	65	
Earnings (loss) from unconsolidated affiliates	$1,118	$ 1,209	$ (57)	$ 3,226	$5,466(4)
Allocated distributions	$1,450	$ —	$ —	$ —	$1,450

Six Months Ended June 30, 2003

(In thousands)

	Coyote	Deepwater Gateway(1)	Poseidon	Total
End of period ownership interest	50%	50%	36%	
Operating results data:				
Operating revenues	$3,825	$ —	$23,207	
Other income	4	23	35	
Operating expenses	(242)	—	(2,160)	
Depreciation	(690)	—	(4,169)	
Other expenses	(387)	(5)	(2,835)	
Net income	$2,510	$ 18	$14,078	
Our share:				
Allocated income	$1,255	$ 9	$ 5,068	
Adjustments(3)	—	(9)	(20)	
Earnings from unconsolidated affiliate	$1,255	$ —	$ 5,048	$6,303
Allocated distributions	$1,750	$ —	$ 6,480	$8,230

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

(2) Cameron Highway Oil Pipeline Company is a development stage company; therefore there are no operating revenues or operating expenses. Since its formation in June 2003, it has incurred organizational expenses and received interest income.

(3) 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.

(4) 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.

6. PARTNERS' CAPITAL

Cash distributions

The following table reflects our per unit cash distributions to our common unitholders and the total distributions paid to our common unitholders, Series C unitholder and general partner during the six months ended June 30, 2004:

Month Paid	Common Unit	Common Unitholders	Series C Unitholder	General Partner
	(Per unit)		(In millions)	
February	$0.71	$41.5	$7.8	$21.3
May	$0.71	$42.4	$7.8	$21.7

In July 2004, we declared a cash distribution of $0.71 per common unit and Series C unit, $50.3 million in the aggregate, for the quarter ended June 30, 2004, which we will pay on August 13, 2004, to holders of record as of July 30, 2004. Also in August 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 June 30, 2004 and August 5, 2004, was $38.47 and $37.10 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 June 30, 2004, and is included in partners' capital as a component of common units capital.

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 June 30, 2004 and December 31, 2003.

In July 2004, 10 Series F1 convertible units were converted into 261,437 common units, for which the holder of the convertible units paid us $10 million. Additionally, our general partner contributed to us $0.1 million in cash in order to maintain its one percent general partner interest.

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 $0.4 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

During the quarter ended June 30, 2004, we granted 4,962 restricted units at a fair value per unit of $38.31 and 8,000 unit options with a grant price of $38.31 to non-employee directors of our Board of Directors under our Director Plan. We accounted for the restricted units in accordance with SFAS No. 123. Under SFAS No. 123, the fair value of these issuances is reflected as deferred compensation and is amortized to compensation expense over the period of service, which we have estimated to be one year. The unit options issued have been accounted for in accordance with APB No. 25. As these options were issued at market value, under the provisions of APB No. 25, no entries were made at the issuance date.

Total unamortized deferred compensation as of June 30, 2004 and December 31, 2003, was approximately $1.2 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.

Net proceeds from unit options exercised during the quarter and six months ended June 30, 2004, were approximately $0.3 million and $4.9 million. Net proceeds from unit options exercised during the quarter and six months ended June 30, 2003, were $0.5 million.

At the close of the merger, any outstanding restricted units issued to (1) employees of El Paso Field Services who will become employees of Enterprise or (2) non-employee directors of our general partner's Board of Directors who will be a member of the Board of Directors of the merged company will convert to Enterprise common units with the same terms, except that the number of Enterprise common units will be adjusted based on the 1.81 exchange ratio. Any outstanding restricted units issued to employees of El Paso Field Services who will not be employees of Enterprise or to non-employee directors of our general partner's Board of Directors who will not be a member of the Board of Directors of the merged company will vest on the merger date and be exchanged for Enterprise common units at the 1.81 exchange ratio.

Unit Option Buyout

Under the merger agreement with Enterprise, we are obligated to repurchase, at reasonable prices, before the effective time of the merger, all outstanding employee and director unit options that have not been exercised or otherwise canceled. Approximately 1,000,000 common unit options were outstanding at June 30, 2004, held by 28 current and former employees and directors. Since we do not have the right under our option plan to force our option holders to sell their options, we were required to negotiate a separate option purchase agreement individually with each option holder. The governance and compensation committee of our general partner's board of directors engaged an independent financial advisor to assist in the determination of the appropriate repurchase prices for the outstanding options. Subsequent to June 30, 2004, we entered into option purchase agreements with all the option holders under which we have agreed to purchase for cash and/or common units, and the option holders have agreed to sell, any options that remain outstanding on the merger closing date for a negotiated price. Each option purchase agreement permits the option holder to exercise any or all of his or her options at any time and from time to time prior to the merger closing. Based on information provided by the financial advisor engaged by the governance and compensation committee, we estimate the value, in the aggregate, of the outstanding options to be repurchased is approximately $13 million.

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 June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Numerator:				
Numerator for basic earnings per common unit —				
Income before cumulative effect of accounting change	$22,022	$24,160	$51,087	$41,614
Cumulative effect of accounting change	—	—	—	1,340
	$22,022	$24,160	$51,087	$42,954
Denominator:				
Denominator for basic earnings per common unit — weighted-average common units	59,649	48,005	59,298	46,024
Effect of dilutive securities:				
Unit options	212	146	244	112
Restricted units	22	9	23	8
Series F convertible units	3	316	1	158
Denominator for diluted earnings per common unit — adjusted for weighted-average common units	59,886	48,476	59,566	46,302
Basic and diluted earnings per common unit				
Income before cumulative effect of accounting change	$ 0.37	$ 0.50	$ 0.86	$ 0.90
Cumulative effect of accounting change	—	—	—	0.03
	$ 0.37	$ 0.50	$ 0.86	$ 0.93

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 June 30, 2004 and 2003, were approximately 17 percent and 15 percent of our total revenue. Revenues received from related parties for the six months ended June 30, 2004 and 2003, were approximately 17 percent and 14 percent of our total revenue.

Our transactions with related parties and affiliates are as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
		(In thousands)		
Revenues received from related parties:				
Natural gas pipelines and plants	$22,827	$26,064	$43,513	$49,014
Oil and NGL logistics	14,847	8,975	30,247	15,844
	$37,674	$35,039	$73,760	$64,858
Expenses paid to related parties:				
Cost of natural gas and other products	$ 6,496	$ 5,842	$16,011	$20,797
Operation and maintenance	23,078	22,093	45,665	45,810
	$29,574	$27,935	$61,676	$66,607
Reimbursements received from related parties:				
Operation and maintenance	$ 663	$ 676	$ 1,629	$ 1,201

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands)			
Revenues received from related parties:				
El Paso Corporation				
El Paso Merchant Energy North America Company	$ 823	$ 7,791	$ 1,508	$18,603
El Paso Production Company	2,358	2,074	4,620	4,432
Tennessee Gas Pipeline Company	227	38	227	93
El Paso Field Services	33,835	25,136	66,791	41,730
Enterprise	431	—	614	—
	$37,674	$35,039	$73,760	$64,858
Cost of natural gas and other products paid to related parties:				
El Paso Corporation				
El Paso Merchant Energy North America Company	$ 6,202	$ 5,427	$15,257	$15,705
El Paso Field Services	235	346	637	5,023
El Paso Natural Gas Company	20	17	39	17
Southern Natural Gas	39	52	78	52
	$ 6,496	$ 5,842	$16,011	$20,797
Operation and maintenance expenses paid to related parties:				
El Paso Corporation				
El Paso Field Services	$22,988	$21,979	$45,443	$45,603
Unconsolidated Subsidiaries				
Poseidon Oil Pipeline Company	90	114	222	207
	$23,078	$22,093	$45,665	$45,810
Reimbursements received from related parties:				
Unconsolidated Subsidiaries				
Cameron Highway	$ 75	$ —	$ 292	$ —
Deepwater Gateway	21	—	204	—
Poseidon Oil Pipeline Company	567	676	1,133	1,201
	$ 663	$ 676	$ 1,629	$ 1,201

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

	June 30, 2004	December 31, 2003
	(In thousands)	
El Paso Corporation		
El Paso Production Company	$ 955	$ 5,991
El Paso Merchant Energy North America Company	3,644	4,113
Tennessee Gas Pipeline Company	1,479	1,350
El Paso Field Services	18,815	16,571
El Paso Natural Gas Company	3,807	4,255
ANR Pipeline Company	980	1,600
Other	106	830
Enterprise	77	—
	29,863	34,710
Unconsolidated Subsidiaries		
Deepwater Gateway	4,888	3,939
Cameron Highway	2,396	9,302
Poseidon	836	—
Other	—	14
	8,120	13,255
Total	$37,983	$47,965

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

	June 30, 2004	December 31, 2003
	(In thousands)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 6,222	$ 7,523
El Paso Production Company	410	4,069
El Paso Field Services	4,572	13,869
Tennessee Gas Pipeline Company	271	1,278
El Paso Natural Gas Company	7,561	942
El Paso Corporation	1,014	6,249
Southern Natural Gas	68	1,871
Other	853	667
	20,971	36,468
Unconsolidated Subsidiaries		
Deepwater Gateway	2,601	2,268
Poseidon	772	—
Other	109	134
	3,482	2,402
Total	$24,453	$38,870

Other Matters

Pipeline Inventory Purchase. In June 2004, we executed an agreement with EPNG, a subsidiary of El Paso Corporation, for the purchase of certain parts and materials inventory. We paid approximately $2.1 million for the items purchased and this inventory is included on our balance sheet as of June 30, 2004, in other current assets.

Petal. In September 2003, Petal entered into a nonbinding letter of intent with Southern Natural Gas Company, a subsidiary of El Paso Corporation, regarding the proposed development and sale of a natural gas storage cavern, and the proposed sale of an undivided interest in the Petal pipeline and other facilities related to that natural gas storage cavern. The new storage cavern would be located at our storage complex near Hattiesburg, Mississippi. In June 2004, Petal and Southern Natural Gas Company terminated their letter of intent and Petal announced that it would hold a nonbinding open season to determine market interest for up to 5.0 Bcf of firm natural gas storage capacity, and up to 500,000 MMBtu/ d of firm transportation on the Petal pipeline, all available in the third quarter of 2007.

Copper Eagle. In August 2003, Arizona Gas Storage, L.L.C., along with its 50 percent partner APACS Holdings L.L.C., sold their interest in Copper Eagle Gas Storage L.L.C. to EPNG. Copper Eagle Gas Storage is developing a natural gas storage project located outside of Phoenix, Arizona. Arizona Gas Storage, L.L.C. is an indirect 60 percent owned subsidiary of us and 40 percent owned by IntraGas US, a Gaz de France North American subsidiary. APACS Holdings L.L.C. is a wholly owned subsidiary of Pinnacle West Energy, a subsidiary of Pinnacle West Capital Corporation. Under the original agreement, we have the right to receive $6.2 million of the sale proceeds, including a note receivable for $4.9 million to be paid quarterly beginning on January 1, 2004, and ending with a final payment on October 1, 2004. In April 2004, Arizona Gas Storage, L.L.C., APACS Holdings, L.L.C. and EPNG agreed to modify the payment schedule related to the Copper Eagle purchase, and the new payment terms are expected to be finalized during the third quarter of 2004. As of June 30, 2004, we have received principal payments totaling $1.3 million and interest payments totaling $45 thousand from EPNG related to the note receivable.

Indemnifications. 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 not made any claims during the six months ended June 30, 2004 or 2003. However, for the full year of 2003, we made claims for approximately $5 million of costs incurred during the year ended December 31, 2003, as costs exceeded the established thresholds for 2003.

Wilson Storage Operating Lease Commitment. In connection with our April 2002 purchase of the EPN Holding assets from subsidiaries of El Paso Corporation, we obtained a long-term operating lease commitment related to the Wilson natural gas storage facility, which is operated by one of our direct subsidiaries. From the acquisition date until the second quarter of 2004, El Paso Corporation guaranteed our direct subsidiary's payment and performance under this commitment. In the second quarter of 2004, El Paso Corporation was released from the guarantee and, thus, we now are solely liable for our direct subsidiary's payment and performance under this operating lease agreement.

Capital Contribution Arrangements. 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 up to $6.1 million, of which $3.0 million has been collected as of June 30, 2004, from ANR Pipeline Company for our Phoenix gathering system, which went into service in July 2004. We expect to receive the remaining amount from ANR Pipeline Company in the third quarter of 2004. The 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.

Unit Option Buyout/ Option Plans. As previously discussed in Note 6, Partners' Capital, we will repurchase employee and director options before the merger and outstanding restricted units will convert to Enterprise restricted units or vest at the merger date.

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. In April 2004, we elected to voluntarily cooperate with the Commodity Futures Trading Commission (CFTC) in connection with the CFTC’s industry-wide investigation of activities affecting the price of natural gas in the fall of 2003. Specifically, the CFTC requested companies to provide information, on behalf of themselves and their affiliates, relating to storage reports provided to the Energy Information Administration for the period of October 2003 through December 2003. We are cooperating fully with the CFTC’s investigation and have provided requested information for the relevant time period regarding our storage operations at our Petal and Wilson fields.

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. 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 court’s calculation of post 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.

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 June 30, 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. We expect to make capital expenditures for environmental matters of approximately $7 million in the aggregate for the years 2004 through 2008, primarily to comply with clean air regulations.

As of June 30, 2004 and December 31, 2003, 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 gas meters. We assumed this liability in connection with our April 2002 acquisition of the EPN Holding assets. As part of the April 2002 EPN Holding asset acquisition, El Paso Corporation has agreed to indemnify us for all the known and unknown environmental liabilities, excluding the remediation costs associated with mercury gas meters, related to the assets we purchased up to the purchase of $752 million. Additionally, 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 $764 million. We will be indemnified for liabilities discovered during the proceeding three years from the closing date of these acquisitions. In addition, we have been indemnified by third parties for remediation costs associated with other assets we have purchased.

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 at the Shoup plant owned by our subsidiary, 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 June 1, 2004. On February 9, 2004, each transmission provider, including Petal and HIOS, filed with the 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. On July 8, 2004, Petal and HIOS filed separate notices with the FERC withdrawing their requests. The FERC has not acted on the requests and they remain pending. However, we believe compliance with this Final Rule should not place an undue burden 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 have filed briefs on exceptions to this decision. In August 2004, HIOS filed an offer of settlement to resolve all issues in the rate case with the FERC. This settlement is the result of negotiations among HIOS and all but one of the customers participating in the rate case. In addition, the FERC Staff is not a party to the settlement. Comments on the settlement are due on August 25, 2004, and reply comments on September 7, 2004. The settlement is subject to the approval of the FERC.

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. This was primarily associated with an unexplained increase in our fuel use which was not contemporaneously collected from our customers. We initially believed 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 2002. We conducted a thorough review of our operations and were unable to determine the exact cause of the increase in fuel use. The fuel use has since returned to historical levels. As of June 30, 2004, we have recorded gross fuel differences of approximately $7.5 million, which we included in our non-current assets on our balance sheet. In the future, we expect to have an opportunity to file for collection of the fuel differences. However, at this time we are not able to determine what amount, if any, may be collectible from our customers. Any amounts we are unable to resolve or collect from our customers will negatively impact the future results of our natural gas pipelines and plants segment.

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. On July 12, 2004, GulfTerra Texas filed its response including its recalculations of rates, plan for unbundling gathering and transmission rates, and its refund plan. The amount of refunds we calculated are immaterial. 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, and the request remains pending.

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 hearing on this matter, scheduled for June 29, 2004, has been postponed and no new hearing date has been established. 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 ventures (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 $11.2 million of unrealized losses included in accumulated other comprehensive income at June 30, 2004, will be reclassified from accumulated other comprehensive income as a reduction to earnings over the next six 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 June 30, 2004 and December 31, 2003, the fair value of these cash flow hedges was a liability of $7.3 million and $5.8 million, as the market price at those dates was higher than the hedge price. For the quarter and six months ended June 30, 2004, we reclassified approximately $2.3 million and $4.0 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income as a decrease in revenue. These reclassifications are included in our natural gas pipelines and plants segment. 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 June 30, 2004 and December 31, 2003, the fair value of these cash flow hedges was a liability of $3.9 million and $3.3 million. For the quarter and six months ended June 30, 2004, we reclassified approximately $2.4 million and $4.6 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income to earnings. These reclassifications are included in our natural gas pipelines and plants segment. 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 had 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”). In March 2004, these cash flow hedges expired and we reclassified a gain of approximately $45 thousand from accumulated other comprehensive income to earnings. This reclassification is included in our natural gas pipelines and plants segment. 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 more balanced 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%. 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 NGL hedging activities is J. Aron and Company, an affiliate of Goldman Sachs, 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 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 periods ended June 30:

	Natural Gas Pipelines and Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Non-Segment Activity[1]	Total
			(In thousands)			
Quarter Ended June 30, 2004						
Revenue from external customers	$ 182,990	$ 19,817	$ 11,743	$ 6,290	$ 4,378	$ 225,218
Intersegment revenue	31	—	—	579	(610)	—
Depreciation, depletion and amortization	18,163	2,513	2,880	1,395	1,129	26,080
Earnings from unconsolidated affiliates	584	1,379	—	1,295	—	3,258
Performance cash flows	83,904	13,252	7,721	5,816	N/A	N/A
Assets	2,344,760	464,228	317,211	175,161	84,721	3,386,081

	Natural Gas Pipelines and Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Non-Segment Activity[(1)]	Total
			(In thousands)			
Quarter Ended June 30, 2003						
Revenue from external customers [(2)]	$ 199,517	$ 16,009	$ 10,871	$ 6,101	$ 4,533	$ 237,031
Intersegment revenue	30	—	186	758	(974)	—
Depreciation, depletion and amortization	17,079	2,167	2,919	1,360	1,321	24,846
Earnings from unconsolidated affiliates	626	2,361	—	—	—	2,987
Performance cash flows	78,386	12,897	8,068	6,277	N/A	N/A
Assets	2,266,522	427,447	324,482	164,120	72,098	3,254,669
Six Months Ended June 30, 2004						
Revenue from external customers	$ 364,493	$ 35,005	$ 24,193	$ 12,932	$ 8,934	$ 445,557
Intersegment revenue	64	—	—	1,164	(1,228)	—
Depreciation, depletion and amortization	35,551	5,605	5,828	2,748	2,571	52,303
Earnings from unconsolidated affiliates	1,118	3,169	(30)	1,209	—	5,466
Performance cash flows	165,917	20,720	16,782	12,179	N/A	N/A
Assets	2,344,760	464,228	317,211	175,161	84,721	3,386,081
Six Months Ended June 30, 2003						
Revenue from external customers [(2)]	$ 396,706	$ 27,977	$ 22,477	$ 10,483	$ 9,483	$ 467,126
Intersegment revenue	68	—	278	1,404	(1,750)	—
Depreciation, depletion and amortization	33,632	4,364	5,881	2,560	2,106	48,543
Earnings from unconsolidated affiliates	1,255	5,048	—	—	—	6,303
Performance cash flows	156,221	24,497	15,069	10,512	N/A	N/A
Assets	2,266,522	427,447	324,482	164,120	72,098	3,254,669

(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 $73.1 million and $121.9 million for the quarter and six months ended June 30, 2003 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 June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands)			
Natural gas pipelines and plants	$ 83,904	$ 78,386	$165,917	$156,221
Oil and NGL logistics	13,252	12,897	20,720	24,497
Natural gas storage	7,721	8,068	16,782	15,069
Platform services	5,816	6,277	12,179	10,512
Segment performance cash flows	110,693	105,628	215,598	206,299
Plus: Other, nonsegment results	3,287	3,011	8,692	8,277
Earnings from unconsolidated affiliates	3,258	2,987	5,466	6,303
Cumulative effect of accounting change	—	—	—	1,690
Less: Interest and debt expense	26,696	31,838	54,727	66,324
Loss due to early redemptions of debt	16,285	—	16,285	3,762
Depreciation, depletion and amortization	26,080	24,846	52,303	48,543
Cash distributions from unconsolidated affiliates	700	3,520	1,450	8,230
Minority interest	—	47	(12)	80
Net cash payment received from El Paso Corporation	—	2,078	1,960	4,118
Net income	$ 47,477	$ 49,297	$103,043	$ 91,512

12. GUARANTOR FINANCIAL INFORMATION

As of June 30, 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 each of our subsidiaries, excluding our unrestricted subsidiaries. Non-guarantor subsidiaries for the quarter and six months ended June 30, 2004, consisted of our unrestricted subsidiaries. Non-guarantor subsidiaries for the quarter and six months ended June 30, 2003, consisted of Matagorda Island Area Gathering System, Arizona Gas Storage, L.L.C., GulfTerra Arizona Gas, L.L.C., Cameron Highway Pipeline GP I, L.L.C., Cameron Highway Pipeline II, L.P., Cameron Highway Pipeline III, L.P., and Cameron Highway Oil Pipeline Company.

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

For the Quarter Ended June 30, 2004

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$148	$225,070	$ —	$225,218
Operating expenses					
Cost of natural gas and other products	—	—	60,095	—	60,095
Operation and maintenance	—	74	51,893	—	51,967
Depreciation, depletion and amortization	36	—	26,044	—	26,080
	36	74	138,032	—	138,142
Operating income (loss)	(36)	74	87,038	—	87,076
Earnings from consolidated affiliates	74,501	—	—	(74,501)	—
Earnings from unconsolidated affiliates	—	—	3,258	—	3,258
Other income	39	—	85	—	124
Interest and debt expense	10,742	(6)	15,960	—	26,696
Loss due to early redemptions of debt	16,285	—	—	—	16,285
Net income	$47,477	$ 80	$ 74,421	$(74,501)	$ 47,477

Condensed Consolidating Statements of Income

For the Quarter Ended June 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries[1]	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$229	$236,802	$ —	$237,031
Operating expenses					
Cost of natural gas and other products	—	—	85,385	—	85,385
Operation and maintenance	2,737	68	45,746	—	48,551
Depreciation, depletion and amortization	37	10	24,799	—	24,846
Loss on sale of long-lived assets	—	—	363	—	363
	2,774	78	156,293	—	159,145
Operating income (loss)	(2,774)	151	80,509	—	77,886
Earnings from consolidated affiliates	62,892	—	—	(62,892)	—
Earnings from unconsolidated affiliates	—	—	2,987	—	2,987
Minority interest expense	—	(47)	—	—	(47)
Other income	203	—	106	—	309
Interest and debt expense	11,024	—	20,814	—	31,838
Net income	$49,297	$104	$ 62,788	$(62,892)	$ 49,297

(1) Operating revenues and cost of natural gas and other products for our guarantor subsidiaries has been reduced by $73.1 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 Statements of Income

For the Six Months Ended June 30, 2004

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$282	$445,275	$ —	$445,557
Operating expenses					
Cost of natural gas and other products	—	—	124,522	—	124,522
Operation and maintenance	—	137	100,326	—	100,463
Depreciation, depletion and amortization	72	—	52,231	—	52,303
Gain on sale of long-lived assets	—	—	(24)	—	(24)
	72	137	277,055	—	277,264
Operating income (loss)	(72)	145	168,220	—	168,293
Earnings from consolidated affiliates	140,335	—	—	(140,335)	—
Earnings (loss) from unconsolidated affiliates	—	(30)	5,496	—	5,466
Minority interest income	—	12	—	—	12
Other income	112	—	172	—	284
Interest and debt expense	21,047	(13)	33,693	—	54,727
Loss due to early redemptions of debt	16,285	—	—	—	16,285
Net income	$103,043	$140	$140,195	$(140,335)	$103,043

Condensed Consolidating Statements of Income

For the Six Months Ended June 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries[1]	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$506	$466,620	$ —	$467,126
Operating expenses					
Cost of natural gas and other products	—	—	176,138	—	176,138
Operation and maintenance	3,204	142	85,849	—	89,195
Depreciation, depletion and amortization	74	21	48,448	—	48,543
Loss on sale of long-lived assets	—	—	257	—	257
	3,278	163	310,692	—	314,133
Operating income (loss)	(3,278)	343	155,928	—	152,993
Earnings from consolidated affiliates	124,397	—	—	(124,397)	—
Earnings from unconsolidated affiliates	—	—	6,303	—	6,303
Minority interest expense	—	(80)	—	—	(80)
Other income	451	—	241	—	692
Interest and debt expense	26,296	—	40,028	—	66,324
Loss due to early redemptions of debt	3,762	—	—	—	3,762
Income before cumulative effect of accounting change	91,512	263	122,444	(124,397)	89,822
Cumulative effect of accounting change	—	—	1,690	—	1,690
Net income	$ 91,512	$263	$124,134	$(124,397)	$ 91,512

(1) Operating revenues and cost of natural gas and other products for our guarantor subsidiaries has been reduced by $121.9 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

June 30, 2004

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 33,445	$ —	$ —	$ —	$ 33,445
Accounts receivable, net					
Trade	—	83	123,348	—	123,431
Affiliates	699,096	267	32,348	(693,728)	37,983
Affiliated note receivable	—	3,713	—	—	3,713
Other current assets	4,022	—	17,648	—	21,670
Total current assets	736,563	4,063	173,344	(693,728)	220,242
Property, plant and equipment, net	9,161	431	2,920,413	—	2,930,005
Intangible assets	—	—	3,177	—	3,177
Investment in unconsolidated affiliates	—	—	203,303	—	203,303
Investment in consolidated affiliates	2,246,481	—	781	(2,247,262)	—
Other noncurrent assets	193,574	—	5,779	(169,999)	29,354
Total assets	$3,185,779	$4,494	$3,306,797	$(3,110,989)	$3,386,081
Current liabilities					
Accounts payable					
Trade	$ —	$ —	$ 124,466	$ —	$ 124,466
Affiliates	26,924	—	691,257	(693,728)	24,453
Accrued interest	8,083	—	—	—	8,083
Current maturities of senior secured term loans	5,000	—	—	—	5,000
Other current liabilities	6,911	—	34,417	—	41,328
Total current liabilities	46,918	—	850,140	(693,728)	203,330
Revolving credit facility	462,000	—	—	—	462,000
Senior secured term loans, less current maturities	493,500	—	—	—	493,500
Long-term debt	923,016	—	—	—	923,016
Other noncurrent liabilities	—	—	212,088	(169,999)	42,089
Minority interest	—	1,801	—	—	1,801
Partners’ capital	1,260,345	2,693	2,244,569	(2,247,262)	1,260,345
Total liabilities and partners’ capital	$3,185,779	$4,494	$3,306,797	$(3,110,989)	$3,386,081

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

For the Six Months Ended June 30, 2004

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 103,043	$ 140	$ 140,195	$(140,335)	$ 103,043
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	72	—	52,231	—	52,303
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	30	(5,496)	—	(5,466)
Distributions from unconsolidated affiliates	—	—	1,450	—	1,450
Gain on sale of long-lived assets	—	—	(24)	—	(24)
Loss due to write-off of unamortized debt issuance costs	3,884	—	—	—	3,884
Amortization of debt issuance costs, premiums and discounts	2,651	—	—	—	2,651
Other noncash items	1,204	24	5,124	—	6,352
Working capital changes, net of acquisitions and noncash transactions	17,564	(75)	(45,450)	—	(27,961)
Net cash provided by operating activities	128,418	119	148,030	(140,335)	136,232
Cash flows from investing activities					
Additions to property, plant and equipment	(1,194)	—	(84,913)	—	(86,107)
Proceeds from sale and retirement of assets	—	—	197	—	197
Additions to investments in unconsolidated affiliates	—	—	(17,947)	—	(17,947)
Net cash used in investing activities	(1,194)	—	(102,663)	—	(103,857)
Cash flows from financing activities					
Net proceeds from revolving credit facility	386,932	—	—	—	386,932
Repayments of revolving credit facility	(307,000)	—	—	—	(307,000)
Net proceeds from senior secured term loan	199,651	—	—	—	199,651
Repayment of senior secured term loan	(1,500)	—	—	—	(1,500)
Debt issuance costs for issuance of long-term debt	(52)	—	—	—	(52)
Repayments of long-term debt	(214,085)	—	—	—	(214,085)
Net proceeds from issuance of common units and conversion of Series F convertible units	48,536	—	—	—	48,536
Advances with affiliates	(94,849)	(119)	(45,367)	140,335	—
Distributions to partners	(142,317)	—	—	—	(142,317)
Contribution from general partner	480	—	—	—	480
Net cash used in financing activities	(124,204)	(119)	(45,367)	140,335	(29,355)
Increase in cash and cash equivalents	$ 3,020	$ —	$ —	$ —	3,020
Cash and cash equivalents at beginning of period					30,425
Cash and cash equivalents at end of period					$ 33,445

Condensed Consolidating Statements of Cash Flows

For the Six Months Ended June 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 91,512	$ 263	$ 124,134	$(124,397)	$ 91,512
Less cumulative effect of accounting change	—	—	1,690	—	1,690
Income before cumulative effect of accounting change	91,512	263	122,444	(124,397)	89,822
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	74	21	48,448	—	48,543
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	—	(6,303)	—	(6,303)
Distributions from unconsolidated affiliates	—	—	8,230	—	8,230
Loss on sale of long-lived assets	—	—	257	—	257
Loss due to write-off of unamortized debt issuance costs	3,762	—	—	—	3,762
Amortization of debt issuance costs, premiums and discounts	3,694	—	322	—	4,016
Other noncash items	592	310	439	—	1,341
Working capital changes, net of acquisitions and noncash transactions	15,333	(546)	(30,289)	—	(15,502)
Net cash provided by operating activities	114,967	48	143,548	(124,397)	134,166
Cash flows from investing activities					
Additions to property, plant and equipment	(584)	(19)	(206,408)	—	(207,011)
Proceeds from sale and retirement of assets	—	—	3,215	—	3,215
Additions to investments in unconsolidated affiliates	—	(197)	—	—	(197)
Net cash used in investing activities	(584)	(216)	(203,193)	—	(203,993)
Cash flows from financing activities					
Net proceeds from revolving credit facility	223,000	—	—	—	223,000
Repayments of revolving credit facility	(298,854)	—	—	—	(298,854)
Repayment of senior secured term loan	(2,500)	—	—	—	(2,500)
Repayment of senior secured acquisition term loan	(237,500)	—	—	—	(237,500)
Net proceeds from issuance of long-term debt	292,479	—	—	—	292,479
Net proceeds from issuance of common units and Series F convertible units	182,182	—	—	—	182,182
Advances with affiliates	(177,653)	168	53,088	124,397	—
Distributions to partners	(107,427)	—	—	—	(107,427)
Contribution from general partner	1	—	—	—	1
Net cash provided by (used in) financing activities	(126,272)	168	53,088	124,397	51,381
Decrease in cash and cash equivalents	$ (11,889)	$ —	$ (6,557)	$ —	(18,446)
Cash and cash equivalents at beginning of period					36,099
Cash and cash equivalents at end of period					$ 17,653
Schedule of noncash financing activities:					
Redemption of Series B preference units contributed from our general partner	$ 1,788	$ —	$ —	$ —	$ 1,788

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 hereunto duly authorized.

ENTERPRISE PRODUCTS PARTNERS L.P.

By: Enterprise Products GP, LLC, as general partner

Date: September 17, 2004

By: /s/ Michael J. Knesek

Michael J. Knesek
Vice President, Controller, and
Principal Accounting Officer of
Enterprise Products GP, LLC