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): December 15, 2003

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)

EXPLANATORY NOTE

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 (1) the consolidated financial statements of GulfTerra as of December 31, 2003 and 2002 and for the three year period ended December 31, 2003, and (2) the financial statements of Poseidon Oil Pipeline Company, L.L.C., an unconsolidated affiliate of GulfTerra, as of December 31, 2003 and 2002 and for the three year period ended December 31, 2003, pursuant to the requirements of S-X Rule 3-05(a) and (b), in connection with Enterprise's proposed merger with GulfTerra. Enterprise is filing these financial statements with this report so that they will be incorporated by reference in its currently effective registration statements.

ITEM 7. FINANCIAL STATEMENTS AND EXHIBITS.

(a) Financial statements of businesses acquired.

1. Consolidated Financial Statements of GulfTerra Energy Partners, L.P. as of December 31, 2003 and 2002 and for the three year period ended December 31, 2003 and independent auditors' report.

2. Financial Statements of Poseidon Oil Pipeline Company, L.L.C. as of December 31, 2003 and 2002 and for the three year period ended December 31, 2003 and independent auditors' report.

REPORT OF INDEPENDENT AUDITORS

To the Unitholders of GulfTerra Energy Partners, L.P.
and the Board of Directors and Stockholders of
GulfTerra Energy Company, L.L.C., as General Partner:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income and changes in accumulated other comprehensive income (loss), partners' capital and cash flows present fairly, in all material respects, the financial position of GulfTerra Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, the Partnership has entered into a definitive agreement to merge with Enterprise Products Partners L.P.

As discussed in Note 1 to the consolidated financial statements, the Partnership changed its method of accounting for asset retirement obligations and its reporting for gains or losses resulting from the extinguishment of debt effective January 1, 2003.

As discussed in Note 1 to the consolidated financial statements, the Partnership changed its method of accounting for the impairment or disposal of long lived assets effective January 1, 2002.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 12, 2004

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Operating revenues			
Natural gas pipelines and plants			
Natural gas sales	$ 171,738	$ 85,001	$ 59,701
NGL sales	121,167	32,978	--
Gathering and transportation	388,777	194,336	33,849
Processing	52,988	45,266	7,133
	734,670	357,581	100,683
Oil and NGL logistics			
Oil sales	2,231	108	--
Oil transportation	26,769	8,364	7,082
Fractionation	22,034	26,356	25,245
NGL storage	2,816	2,817	--
	53,850	37,645	32,327
Platform services	20,861	16,672	15,385
Natural gas storage	44,297	28,602	19,373
Other -- oil and natural gas production	17,811	16,890	25,638
	871,489	457,390	193,406
Operating expenses			
Cost of natural gas and other products	287,157	108,819	51,542
Operation and maintenance	189,702	115,162	33,279
Depreciation, depletion and amortization	98,846	72,126	34,778
Asset impairment charge	--	--	3,921
(Gain) loss on sale of long-lived assets	(18,679)	473	11,367
	557,026	296,580	134,887
Operating income	314,463	160,810	58,519
Earnings from unconsolidated affiliates	11,373	13,639	8,449
Minority interest income (expense)	(917)	60	(100)
Other income	1,206	1,537	28,726
Interest and debt expense	127,830	81,060	41,542
Loss due to early redemptions of debt	36,846	2,434	--
Income from continuing operations	161,449	92,552	54,052
Income from discontinued operations	--	5,136	1,097
Cumulative effect of accounting change	1,690	--	--
Net income	$ 163,139	$ 97,688	$ 55,149

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME -- (CONTINUED)
(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)

YEAR ENDED DECEMBER 31,	2003	2002	2001
Income allocation			
Series B unitholders	$11,792	$14,688	$17,228
General partner			
Income from continuing operations	$69,414	$42,082	$24,650
Income from discontinued operations	--	51	11
Cumulative effect of accounting change	17	--	--
	$69,431	$42,133	$24,661
Common unitholders			
Income from continuing operations	$65,155	$34,275	$12,174
Income from discontinued operations	--	5,085	1,086
Cumulative effect of accounting change	1,340	--	--
	$66,495	$39,360	$13,260
Series C unitholders			
Income from continuing operations	$15,088	$ 1,507	$ --
Cumulative effect of accounting change	333	--	--
	$15,421	$ 1,507	$ --
Basic earnings per common unit			
Income from continuing operations	$ 1.30	$ 0.80	$ 0.35
Income from discontinued operations	--	0.12	0.03
Cumulative effect of accounting change	0.03	--	--
Net income	$ 1.33	$ 0.92	$ 0.38
Diluted earnings per common unit			
Income from continuing operations	$ 1.30	$ 0.80	$ 0.35
Income from discontinued operations	--	0.12	0.03
Cumulative effect of accounting change	0.02	--	--
Net income	$ 1.32	$ 0.92	$ 0.38
Basic weighted average number of common units outstanding	49,953	42,814	34,376
Diluted weighted average number of common units outstanding	50,231	42,814	34,376

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS)

DECEMBER 31,	2003	2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 30,425	$ 36,099
Accounts receivable, net		
Trade	43,203	90,379
Unbilled trade	63,067	49,140
Affiliates	47,965	83,826
Affiliated note receivable	3,768	--
Other current assets	20,595	3,451
Total current assets	209,023	262,895
Property, plant and equipment, net	2,894,492	2,724,938
Intangible assets	3,401	3,970
Investments in unconsolidated affiliates	175,747	95,951
Other noncurrent assets	38,917	43,142
Total assets	$3,321,580	$3,130,896
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable		
Trade	$ 113,820	$ 120,140
Affiliates	38,870	86,144
Accrued gas purchase costs	15,443	6,584
Accrued interest	11,199	15,028
Current maturities of senior secured term loan	3,000	5,000
Other current liabilities	27,035	21,195
Total current liabilities	209,367	254,091
Revolving credit facility	382,000	491,000
Senior secured term loans, less current maturities	297,000	552,500
Long-term debt	1,129,807	857,786
Other noncurrent liabilities	49,043	23,725
Total liabilities	2,067,217	2,179,102
Commitments and contingencies		
Minority interest	1,777	1,942
Partners' capital		
Limited partners		
Series B preference units; 125,392 units in 2002 issued and outstanding	--	157,584
Common units; 58,404,649 and 44,030,314 units in 2003 and 2002 issued and outstanding	898,072	433,150
Series C units; 10,937,500 units in 2003 and 2002 issued and outstanding	341,350	350,565
General partner	13,164	8,553
Total partners' capital	1,252,586	949,852
Total liabilities and partners' capital	$3,321,580	$3,130,896

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Cash flows from operating activities			
Net income	$ 163,139	$ 97,688	$ 55,149
Less cumulative effect of accounting change	1,690	--	--
Less income from discontinued operations	--	5,136	1,097
Income from continuing operations	161,449	92,552	54,052
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	98,846	72,126	34,778
Asset impairment charge	--	--	3,921
Distributed earnings of unconsolidated affiliates			
Earnings from unconsolidated affiliates	(11,373)	(13,639)	(8,449)
Distributions from unconsolidated affiliates	12,140	17,804	35,062
(Gain) loss on sale of long-lived assets	(18,679)	473	11,367
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	12,544	2,434	--
Amortization of debt issuance costs	7,498	4,443	3,608
Other noncash items	3,445	4,429	544
Working capital changes, net of acquisitions and non-cash transactions			
Accounts receivable	66,441	(167,536)	(41,037)
Other current assets	(9,762)	(12,612)	125
Other noncurrent assets	(1,540)	467	(10,379)
Accounts payable	(45,829)	143,553	(672)
Accrued gas purchase costs	8,859	4,223	(2,776)
Accrued interest	(3,829)	9,330	3,574
Other current liabilities	(8,928)	13,086	(235)
Other noncurrent liabilities	(3,114)	(377)	(1,067)
Net cash provided by continuing operations	268,168	170,756	82,416
Net cash provided by discontinued operations	--	5,244	4,968
Net cash provided by operating activities	268,168	176,000	87,384
Cash flows from investing activities			
Development expenditures for oil and natural gas properties	(145)	(1,682)	(2,018)
Additions to property, plant and equipment	(332,019)	(202,541)	(508,347)
Proceeds from the sale and retirement of assets	77,911	5,460	109,126
Additions to investments in unconsolidated affiliates	(35,536)	(38,275)	(1,487)
Proceeds from the sale of investments in unconsolidated affiliates	1,355	--	--
Repayments on note receivable	1,238	--	--
Cash paid for acquisitions, net of cash acquired	(20)	(1,164,856)	(28,414)
Net cash used in investing activities of continuing operations	(287,216)	(1,401,894)	(431,140)
Net cash provided by (used in) investing activities of discontinued operations	--	186,477	(68,560)
Net cash used in investing activities	(287,216)	(1,215,417)	(499,700)

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS -- (CONTINUED)
(IN THOUSANDS)

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Cash flows from financing activities			
Net proceeds from revolving credit facility	533,564	366,219	559,994
Repayments of revolving credit facility	(647,000)	(177,000)	(581,000)
Net proceeds from GulfTerra Holding term credit facility	--	530,136	--
Repayment of GulfTerra Holding term credit facility	--	(375,000)	--
Repayment of GulfTerra Holding term loan	(160,000)	--	--
Net proceeds from senior secured acquisition term loan	(23)	233,236	--
Repayment of senior secured acquisition term loan	(237,500)	--	--
Net proceeds from senior secured term loan	299,512	156,530	--
Repayment of senior secured term loan	(160,000)	--	--
Net proceeds from issuance of long-term debt	537,426	423,528	243,032
Repayments of long-term debt	(269,401)	--	--
Repayment of Argo term loan	--	(95,000)	--
Distributions to minority interests	(1,242)	--	--
Net proceeds from issuance of common units	509,010	150,159	286,699
Redemption of Series B preference units	(155,673)	--	(50,000)
Contributions from general partner	3,098	4,095	2,843
Distributions to partners	(238,397)	(154,468)	(106,409)
Net cash provided by financing activities of continuing operations	13,374	1,062,435	355,159
Net cash provided by (used in) financing activities of discontinued operations	--	(3)	49,960
Net cash provided by financing activities	13,374	1,062,432	405,119
Increase (decrease) in cash and cash equivalents	(5,674)	23,015	(7,197)
Cash and cash equivalents at beginning of year	36,099	13,084	20,281
Cash and cash equivalents at end of year	$ 30,425	$ 36,099	$ 13,084

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(IN THOUSANDS)

SERIES B SERIES B
PREFERENCE PREFERENCE
SERIES C SERIES C
COMMON COMMON GENERAL
UNITS(1) UNITHOLDERS
UNITS(2) UNITHOLDERS
UNITS UNITHOLDERS
PARTNER(3) TOTAL ------
---- ---------- ------
-- ---------- ------ -
---------- ---------- -
--------- Partners'
capital at January 1,
2001......... 170 $
175,668 -- $ -- 31,550
$ 132,802 $ 2,601 $
311,071 Net
income(4).............
-- 17,228 -- -- --
13,260 24,661 55,149
Other comprehensive
loss....................
-- -- -- -- -- (1,259)
(13) (1,272) Issuance
of common
units...................
-- -- -- -- 8,189
286,699 -- 286,699
Issuance of unit
options.................
-- -- -- 2,161 -- 2,161
Redemption of Series B
preference
units........ (45)
(50,000) -- -- -- -- --
(50,000) General
partner contribution
related to the issuance
of common
units...................
-- -- -- -- -- -- 2,843
2,843 Cash
distributions........ -
- -- -- -- -- (80,903)
(25,022) (105,925) ----
--------- ------ ------
-- ------ --------- ---
----- ----------
Partners' capital at
December 31,
2001....... 125 $
142,896 -- $ -- 39,739
$ 352,760 $ 5,070 $
500,726 Net
income(4).............
-- 14,688 -- 1,507 --
39,360 42,133 97,688
Issuance of Series C
units...................
-- -- 10,938 350,000 --
-- -- 350,000 Other
comprehensive
loss....................
-- -- -- (942) --
(3,364) (44) (4,350)
Issuance of common
units...................
-- -- -- -- 4,291
156,072 -- 156,072
Issuance of unit
options.................
-- -- -- -- -- 89 -- 89
General partner
contribution related to

the issuance of Series
C units and common
units..................
-- -- -- -- -- -- 4,095
4,095 Cash
distributions........ -
- -- -- -- -- (111,767)
(42,701) (154,468) ----
--------- ------ ------
-- ------ --------- ---
----- ----------
Partners' capital at
December 31,
2002....... 125 $
157,584 10,938 $350,565
44,030 $ 433,150 $
8,553 $ 949,852 Net
income(4).............
-- 11,792 -- 15,421
66,495 69,431 163,139
Other comprehensive
loss...................
-- -- (467) -- (2,865)
(73) (3,405) Issuance
of common
units..................
-- -- -- -- 14,056
494,812 -- 494,812
Issuance of Series F
units..................
-- -- -- -- -- 4,104 --
4,104 Redemption of
unit
options................
-- -- -- -- 319 10,094
-- 10,094 Redemption of
Series B preference
units........ (125)
(169,376) -- 1,919 --
9,686 2,098 (155,673)
Issuance of unit
options and restricted
units.... 1,687 1,687
General partner
contribution related to
the issuance of common
units..................
-- -- -- -- -- -- 3,098
3,098 Receipt of
communication
assets.................
-- -- -- 4,100 --
18,942 233 23,275 Cash
distributions........ -
- -- -- (30,188) --
(138,033) (70,176)
(238,397) ---- --------
- ------ -------- -----
- --------- -------- --
-------- Partners'
capital at December 31,
2003....... -- $ --
10,938 $341,350 58,405
$ 898,072 $ 13,164
$1,252,586 ====
========= ======
======== ======
========= ========
==========

- ---------------
(1) In October 2003, we redeemed all of our remaining outstanding Series B
    preference units for $156 million.
(2) We issued 10,937,500 of our Series C units to El Paso Corporation for a
    value of $350 million in connection with our acquisition of the San Juan
    assets. A discussion of this new class of units is included in Note 8.
(3) GulfTerra Energy Company, L.L.C. is our sole general partner and is owned 50
    percent by a subsidiary of El Paso Corporation and 50 percent by a
    subsidiary of Enterprise Products Partners, L.P.
(4) Income allocation to our general partner includes both its incentive

distributions and its one percent ownership interest.

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)
(IN THOUSANDS)

COMPREHENSIVE INCOME

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Net income	$163,139	$97,688	$55,149
Other comprehensive loss	(3,405)	(4,350)	(1,272)
Total comprehensive income	$159,734	$93,338	$53,877

ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Beginning balance	$ (5,622)	$(1,272)	$ --
Unrealized mark-to-market losses on cash flow hedges arising during period	(12,924)	(6,428)	(1,682)
Reclassification adjustments for changes in initial value of derivative instruments to settlement date	10,018	1,579	410
Accumulated other comprehensive income (loss) from investment in unconsolidated affiliate	(499)	499	--
Ending balance	$ (9,027)	$(5,622)	$(1,272)

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

We are a publicly held Delaware master limited partnership 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. As of December 31, 2003, we had 58,404,649 common units outstanding representing limited partner interests and 10,937,500 Series C units outstanding representing non-voting limited partner interests. On that date, the public owned 48,020,404 common units, or 82.2 percent of our outstanding common units, and El Paso Corporation, through its subsidiaries, owned 10,384,245 common units, or 17.8 percent of our outstanding common units, all of our Series C units and 50 percent of our general partner, which owns our one percent general partner interest.

In May 2003, we changed our name to GulfTerra Energy Partners, L.P. from El Paso Energy Partners, L.P. and reorganized our general partner. In connection with our name change, we also changed the names of several subsidiaries in May 2003, including the following, as listed in the table below.

NEW NAME	FORMER NAME
GulfTerra Energy Finance Corporation.....	El Paso Energy Partners Finance Corporation
GulfTerra Arizona Gas, L.L.C.............	El Paso Arizona Gas, L.L.C.
GulfTerra Intrastate, L.P................	El Paso Energy Intrastate, L.P.
GulfTerra Texas Pipeline, L.P............	EPGT Texas Pipeline, L.P.
GulfTerra Holding V, L.P.................	EPN Holding Company, L.P.

Our sole general partner is GulfTerra Energy Company, L.L.C., a recently-formed Delaware limited liability company that is owned 50 percent by a subsidiary of El Paso Corporation and 50 percent by a subsidiary of Enterprise, a publicly traded master limited partnership. El Paso Corporation (through its subsidiaries) owned 100 percent of our general partner until October 2003, when Goldman Sachs acquired a 9.9 percent interest in our general partner. In December 2003, El Paso Corporation reacquired Goldman Sachs' interest in our general partner and then sold a 50 percent interest in our general partner to a subsidiary of 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 with Enterprise being the continuing entity. The general partner of the combined partnership will be jointly owned by affiliates of El Paso Corporation and privately-held Enterprise Products Company, with each owning a 50-percent interest.

The combined partnership, which will retain the name Enterprise Products Partners L.P., will serve the largest producing basins of natural gas, crude oil and NGLs in the U.S., including the Gulf of Mexico, Rocky Mountains, San Juan Basin, Permian Basin, South Texas, East Texas, Mid-Continent and Louisiana Gulf Coast basins and, through connections with third-party pipelines, Canada's western sedimentary basin. The partnership will also serve the largest consuming regions for natural gas, crude oil and NGLs on the U.S. Gulf Coast.

Basis of Presentation and Principles of Consolidation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. We account for investments in companies where we have the ability to exert significant influence over, but not control over operating and financial policies, using the equity method of accounting. Prior to May 2001, our general partner's approximate one percent non-managing interest in twelve of our subsidiaries represented the minority interest in our consolidated financial statements. In May 2001, we purchased our general partner's one percent non-managing ownership interest in twelve of our subsidiaries for $8 million. As a result of this acquisition, all of our subsidiaries, but not our equity investees, are wholly-owned by us.

During part of 2003 and 2002, third parties had minority ownership interests in Matagorda Island Area Gathering System (MIAGS) and Arizona Gas, L.L.C. The assets, liabilities and operations of these entities are included in our consolidated financial statements and we account for the third party ownership interest as minority interest in our consolidated balance sheets and as minority interest income (expense) in our consolidated statements of income. In October 2003, we purchased the remaining 17 percent interest in MIAGS. As a result, we no longer recognize the third party ownership interest in MIAGS as minority interests in our consolidated balance sheets or consolidated statements of income.

Our consolidated financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications have no impact on reported net income or partners' capital. We have reflected the results of operations from our Prince assets disposition as discontinued operations for the years ended December 31, 2002 and 2001. See Note 2 for a further discussion of our Prince assets disposition.

Use of Estimates

The preparation of our financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities that exist at the date of our financial statements. While we believe our estimates are appropriate, actual results can, and often do, differ from those estimates.

Accounting for Regulated Operations

Our HIOS interstate natural gas system and our Petal storage facility are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each system operates under separate FERC approved tariffs that establish rates, terms and conditions under which each system provides services to its customers. Our businesses that are subject to the regulations and accounting requirements of FERC have followed the accounting requirements of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation, which may differ from the accounting requirements of our non-regulated entities. Transactions that have been recorded differently as a result of regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects.

Under the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations, which we adopted on January 1, 2003, the cost associated with the retirement of long-lived assets for regulated entities accounted for under SFAS No. 71 should be classified as a regulatory liability instead of as a component of property, plant and equipment. As a result, we reclassified $13.6 million from property, plant and equipment to a regulatory liability and at December 31, 2003, this balance is included in other noncurrent liabilities in our consolidated balance sheet. Prior to January 2003, this item was reflected in accumulated depreciation, depletion and amortization and the balance for this item at December 31, 2002, was $12.9 million.

When the accounting method followed is required by or allowed by the regulatory authority for rate-making purposes, the method conforms to the generally accepted accounting principle (GAAP) of matching costs with the revenues to which they apply.

Cash and Cash Equivalents

We consider short-term investments with little risk of change in value because of changes in interest rates and purchased with an original maturity of less than three months to be cash equivalents.

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. At December 31, 2003 and 2002, the allowance was $4.0 million and $2.5 million.

Natural Gas Imbalances

Natural gas imbalances result from differences in gas volumes received from and delivered to our customers and arise when a customer delivers more or less gas into our pipelines than they take out. These imbalances are settled in kind through a tracking mechanism, negotiated cash-outs between parties, or are subject to a cash-out procedure and are valued at prices representing the estimated value of these imbalances upon settlement. We estimate the value of our imbalances at prices representing the estimated value of the imbalances upon settlement. Changes in natural gas prices may impact our valuation. We do not value our imbalances based on current month-end spot prices because it is not likely that we would purchase or receive natural gas at that point in time to settle the imbalance. Natural gas imbalances are reflected in accounts receivable or accounts payable, as appropriate, in our accompanying consolidated balance sheets. Our imbalance receivables and imbalance payables were as follows at December 31 (in thousands):

	2003	2002
Imbalance Receivables		
Trade	$37,228	$ 88,929
Affiliates	$16,405	$ 15,460
Imbalance Payables		
Trade	$68,446	$104,035
Affiliates	$14,047	$ 22,316

Property, Plant and Equipment

We record our property, plant and equipment at its original cost of construction or, upon acquisition, the fair value of the asset acquired. Additionally, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and, in our regulated businesses that apply the provisions of SFAS No. 71, an equity return component. We also capitalize the major units of property replacements or improvements and expense minor items including repair and maintenance costs. In addition, we reduce our property, plant and equipment balance for any amounts that we receive in the form of contributions in aid of construction.

For our regulated interstate system and storage facility we use the composite (group) method to depreciate regulated property, plant and equipment. Under this method, assets with similar lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate approved in our tariff to the total cost of the group until its net book value equals its estimated salvage value. Currently, depreciation rates on our regulated interstate system and storage facility vary from 1 to 20 percent. Using these rates, the remaining depreciable lives of these assets range from 1 to 39 years.

Our non-regulated gathering pipelines, platforms and related facilities, processing facilities and equipment, and storage facilities and equipment are depreciated on a straight-line basis over the estimated useful lives which are as follows:

Gathering pipelines	5-40 years
Platforms and facilities	18-30 years
Processing facilities	25-30 years
Storage facilities	25-30 years

We account for our oil and natural gas exploration and production activities using the successful efforts method of accounting. Under this method, costs of successful exploratory wells, developmental wells and acquisitions of mineral leasehold interests are capitalized. Production, exploratory dry hole and other exploration costs, including geological and geophysical costs and delay rentals, are expensed as incurred. Unproved properties are assessed periodically and any impairment in value is recognized currently as depreciation, depletion and amortization expense.

Depreciation, depletion and amortization of the capitalized costs of producing oil and natural gas properties, consisting principally of tangible and intangible costs incurred in developing a property and costs of productive leasehold interests, are computed on the unit-of-production method. Unit-of-production rates are based on annual estimates of remaining proved developed reserves or proved reserves, as appropriate, for each property.

Estimated dismantlement, restoration and abandonment costs and estimated residual salvage values are taken into account in determining depreciation provisions for gathering pipelines, platforms, related facilities and oil and natural gas properties. At December 31, 2002, accrued abandonment costs were $24.6 million, of which $6.4 million was related to offshore wells. As discussed below, we adopted SFAS No. 143 Accounting for Asset Retirement Obligations on January 1, 2003 and the amounts accrued and capitalized were adjusted to conform to the provisions of that statement.

Retirements, sales and disposals of assets are recorded by eliminating the related costs and accumulated depreciation, depletion and amortization of the disposed assets with any resulting gain or loss reflected in income.

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143. The provisions of this statement relate primarily to our obligations to plug abandoned offshore wells that constitute part of our non-segment assets.

Upon our adoption of SFAS No. 143, we recorded (i) a $7.4 million net increase to property, plant, and equipment, relating to offshore wells, representing non-current retirement assets, (ii) a $5.7 million increase to noncurrent liabilities representing retirement obligations, and (iii) a $1.7 million increase to income as a cumulative effect of accounting change. Each retirement asset is depreciated over the remaining useful life of the long-term asset with which the retirement liability is associated. An ongoing expense is recognized for the interest component of the liability due to the changes in the value of the retirement liability as a result of the passage of time, which we reflect as a component of depreciation expense in our income statement.

Other than our obligations to plug and abandon wells, we cannot estimate the costs to retire or remove assets used in our business because we believe the assets do not have definite lives or we do not have the legal obligation to abandon or dismantle the assets. We believe that the lives of our assets or the underlying reserves associated with our assets cannot be estimated. Therefore, aside from the liability associated with the plugging and abandonment of offshore wells, we have not recorded liabilities relating to any of our other assets.

The pro forma income from continuing operations and amounts per common unit for the years ended December 31, 2002 and 2001, assuming the provisions of SFAS No. 143 were adopted prior to the earliest period presented, are shown below:

	YEARS ENDED DECEMBER 31, 2002	2001
Pro forma income from continuing operations	$93,932	$54,321
Pro forma income from continuing operations allocated to common unitholders	$35,369	$12,446
Pro forma basic income from continuing operations per weighted average common unit	$ 0.83	$ 0.36
Pro forma diluted income from continuing operations per weighted average common unit	$ 0.83	$ 0.36

The pro forma amount of our asset retirement obligations at December 31, 2002 and 2001, assuming asset retirement obligations as provided for in SFAS No. 143 were recorded prior to the earliest period presented was $5.7 million and $5.3 million. Our asset retirement obligation for December 31, 2003, is shown below.

	LIABILITY BALANCE AS OF JANUARY 1	ACCRETION	OTHER CHANGE IN LIABILITY	LIABILITY BALANCE AS OF DECEMBER 31
	(IN THOUSANDS)			
2003	$5,726	$442	$(246)(1)	5,922

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(1) Abandonment work performed during the year ended December 31, 2003.

Goodwill and Other Intangible Assets

We adopted the provisions of SFAS No. 142 Goodwill and Other Intangible Assets on January 1, 2002, except for goodwill and intangible assets we acquired after June 30, 2001 for which we adopted the provisions immediately. Accordingly, we record identifiable intangible assets we acquire individually or with a group of other assets at fair value upon acquisition. Identifiable intangible assets with finite useful lives are amortized to expense over the estimated useful life of the asset. Identifiable intangible assets with indefinite useful lives and goodwill are evaluated annually for impairment by comparison of their carrying amounts with the fair value of the individual assets. We recognize an impairment loss in income for the amount by which the carrying value of any identifiable intangible asset or goodwill exceeds the fair value of the specific assets. As of December 31, 2003 and 2002, we had no goodwill, other than as described below.

As of December 31, 2003 and 2002, the carrying amount of our equity investment in Poseidon exceeded the underlying equity in net assets by approximately $3.0 million. With our adoption of SFAS No. 142 on January 1, 2002, we no longer amortize this excess amount and will test it for impairment if an event occurs that indicates there may be a loss in value, or at least annually. Prior to January 1, 2002, we amortized this excess amount using the straight line method over approximately 30 years. This excess amount is reflected on our accompanying consolidated balance sheets in investments in unconsolidated affiliates. Our adoption of this statement did not have a material impact on our financial position or results of operations.

As part of our acquisition of the EPN Holding assets and the San Juan assets, we obtained intangible assets representing contractual rights under dedication and transportation agreements with producers. As of December 31, 2003 and 2002, the value of these intangible assets was approximately $3.4 million and

$4.0 million and is reflected on our accompanying consolidated balance sheets as intangible assets. We amortize the intangible assets acquired in the EPN Holding asset acquisition to expense using the units-of-production method over the expected lives of the reserves ranging from 26 to 45 years. We amortize the intangible assets acquired in the San Juan asset acquisition over the life of the contracts of approximately 4 years.

Impairment and Disposal of Long-Lived Assets

We apply the provisions of SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets to account for impairment and disposal of long-lived assets. Accordingly, we evaluate the recoverability of long-lived assets when adverse events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. We determine the recoverability of an asset or group of assets by estimating the undiscounted cash flows expected to result from the use and eventual disposition of the asset or group of assets at the lowest level for which separate cash flows can be measured. If the total of the undiscounted cash flows is less that the carrying amount for the assets, we estimate the fair value of the asset or group of assets and recognize the amount by which the carrying value exceeds the fair value, less cost to sell, as an impairment loss in income from operations in the period the impairment is determined.

Additionally, as required by SFAS No. 144, we classify long-lived assets to be disposed of other than by sale (e.g., abandonment, exchange or distribution) as held and used until the item is abandoned, exchanged or distributed. We evaluate assets to be disposed of other than by sale for impairment and recognize a loss for the excess of the carrying value over the fair value. Long-lived assets to be disposed of through sale recognition meeting specific criteria are classified as "Held for Sale" and measured at the lower of their cost or fair value less cost to sell. We report the results of operations of a component classified as held for sale, including any gain or loss in the period(s) in which they occur. Upon our adoption of SFAS No. 144, we reclassified our losses on the sale of long-lived assets of $0.4 million and $11.4 million for the years ended December 31, 2002 and 2001, into operating income to conform with the provisions of SFAS No. 144.

We also reclassify the asset or assets as either held for sale or as discontinued operations, depending on whether they have independently determinable cash flow and whether we have any continuing involvement.

Capitalization of Interest

Interest and other financing costs are capitalized in connection with construction and drilling activities as part of the cost of the asset and amortized over the related asset's estimated useful life.

Debt Issue Costs

Debt issue costs are capitalized and amortized over the life of the related indebtedness using the effective interest method. Any unamortized debt issue costs are expensed at the time the related indebtedness is repaid or terminated. At December 31, 2003 and 2002, the unamortized amount of our debt issue costs included in other noncurrent assets was $29.2 million and $32.6 million. Amortization of debt issue costs for the years ended December 31, 2003, 2002 and 2001 were $7.5 million, $4.4 million and $3.6 million and are included in interest and debt expense on our consolidated statements of income.

Revenue Recognition and Cost of Natural Gas and Other Products

Revenue from gathering and transportation of hydrocarbons is recognized upon receipt of the hydrocarbons into the pipeline systems. Revenue from commodity sales is recognized upon delivery. Commodity storage revenues and platform access revenues consist primarily of fixed fees for capacity reservation and some of the transportation contracts on our Viosca Knoll system and our Indian Basin lateral also contain a fixed fee to reserve transportation capacity. These fixed fees are recognized during the month in which the capacity is reserved by the customer, regardless of how much capacity is actually used. Revenue from processing services, treating services and fractionation services is recognized in the period the services are provided. Interruptible revenues from natural gas storage, which are generated by providing excess storage capacity, are variable in nature and are recognized when the service is provided. Other revenues generally are recorded when services have been provided or products have been delivered.

Prior to 2002, our cost of natural gas consisted primarily of natural gas purchased at GulfTerra Alabama Intrastate for resale. As a result of our acquisition of the EPN Holding assets and the San Juan assets, we are now incurring additional costs related to system imbalances and for the purchase of natural gas as part of our producer services activities. As a convenience for our producers, we may purchase natural gas from them at the wellhead at an index price less an amount that compensates us for our gathering services. We then sell this gas into the open market at points on our system at the same index price. We reflect these sales in our revenues and the related purchases as cost of natural gas on the accompanying consolidated statements of income.

Typhoon Oil Pipeline's transportation agreement with BHP and Chevron Texaco provides 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. Beginning in 2003, we record revenue from these buy/sell transactions upon delivery of the oil based on the net amount billed to the producers. We acquired the Typhoon oil pipeline in November 2002, and for the year ended December 31, 2002, we recorded revenue based on the gross amount billed to the producers. For the year ended December 31, 2002, we reclassified $10.5 million from cost of natural gas and other products to revenue to conform to our 2003 presentation. This reclassification has no effect on operating income, net income or partners' capital.

As of July 1, 2003, HIOS implemented new rates, subject to a refund, and we established a reserve for our estimate of the 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.

Environmental Costs

We expense or capitalize expenditures for ongoing compliance with environmental regulations that relate to past or current operations as appropriate. We expense amounts for clean up of existing environmental contamination caused by past operations which do not benefit future periods. We record liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the Environmental Protection Agency (EPA) or other organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included in our consolidated balance sheets in other noncurrent liabilities at their undiscounted amounts.

Accounting for Price Risk Management Activities

Our business activities expose us to a variety of risks, including commodity price risk and interest rate risk. From time to time we engage in price risk management activities for non-trading purposes to manage market risks associated with commodities we purchase and sell and interest rates on variable rate debt. Our price risk management activities involve the use of a variety of derivative financial instruments, including:

- exchange-traded future contracts that involve cash settlement;

- forward contracts that involve cash settlements or physical delivery of a commodity; and

- swap contracts that require payments to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices, for a commodity or variable rate debt instrument.

We account for all of our derivative instruments in our consolidated financial statements under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. We record all derivatives in our consolidated balance sheets at their fair value as other assets or other liabilities and classify them as current or noncurrent based upon their anticipated settlement date.

For those instruments entered into to hedge risk and which qualify as hedges, we apply the provisions of SFAS No. 133, and the accounting treatment depends on each instrument's intended use and how it is designated. In addition to its designation, a hedge must be effective. To be effective, changes in the value of the derivative or its resulting cash flows must substantially offset changes in the value or cash flows of the item being hedged.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategies for undertaking various hedge transactions. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair values of the hedged items. We discontinue hedge accounting prospectively if we determine that a derivative is not highly effective as a hedge or if we decide to discontinue the hedging relationship.

During 2003, 2002 and 2001, we entered into cash flow hedges that qualify for hedge accounting under SFAS No. 133 treatment. Changes in the fair value of a derivative designated as a cash flow hedge are recorded in accumulated other comprehensive income for the portion of the change in value of the derivative that is effective. The ineffective portion of the derivative is recorded in earnings in the current period. Classification in the income statement of the ineffective portion is based on the income classification of the item being hedged. At the date of the hedged transaction, we reclassify the gains or losses resulting from the sale, maturity, extinguishment or termination of derivative instruments designated as hedges from accumulated other comprehensive income to operating income or interest expense, as appropriate, in our consolidated statements of income. We classify cash inflows and outflows associated with the settlement of our derivative transactions as cash flows from operating activities in our consolidated statements of cash flows.

We also record our ownership percentage of the changes in the fair value of derivatives of our investments in unconsolidated affiliates in accumulated other comprehensive income.

We may also purchase and sell instruments to economically hedge price fluctuations in the commodity markets. These instruments are not documented as hedges due to their short-term nature, or do not qualify under the provisions of SFAS No. 133 for hedge accounting due to the terms in the instruments. Where such derivatives do not qualify, or are not documented, changes in their fair value are recorded in earnings in the current period.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices in the San Juan Basin in anticipation of our acquisition of the San Juan assets. From August 2002 through our acquisition date, November 27, 2002, we accounted for this derivative through current earnings since it did not qualify for hedge accounting under SFAS No. 133. Beginning with the acquisition date in November 2002, we have designated this derivative as a cash flow hedge and are accounting for it as such under SFAS No. 133.

During the normal course of our business, we may enter into contracts that qualify as derivatives under the provisions of SFAS No. 133. As a result, we evaluate our contracts to determine whether derivative accounting is appropriate. Contracts that meet the criteria of a derivative and qualify as "normal purchases" and "normal sales", as those terms are defined in SFAS No. 133, may be excluded from SFAS No. 133 treatment.

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. This statement amends SFAS No. 133 to incorporate several interpretations of the Derivatives Implementation Group (DIG), and also makes several minor modifications to the definition of a derivative as it was defined in SFAS No. 133. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003. There was no initial financial statement impact of adopting this standard, although the FASB and DIG continue to deliberate on the application of the standard to certain derivative contracts, which may impact our financial statements in the future.

Income Taxes

As of December 31, 2003, neither we nor any of our subsidiaries are taxable entities. However, the taxable income or loss resulting from our operations will ultimately be included in the federal and state income tax returns of the general and limited partners. Individual partners will have different investment bases depending upon the timing and price of their acquisition of partnership units. Further, each partner's tax accounting, which is partially dependent upon his tax position, may differ from the accounting followed in the consolidated financial statements. Accordingly, there could be significant differences between each individual partner's tax basis and his share of the net assets reported in the consolidated financial statements. We do not have access to information about each individual partner's tax attributes and the aggregate tax bases cannot be readily determined.

Income (Loss) per Common Unit

Basic income (loss) per common unit excludes dilution and is computed by dividing net income (loss) attributable to the common unitholders by the weighted average number of common units outstanding during the period. Diluted income (loss) per common unit reflects potential dilution and is computed by dividing net income (loss) attributable to the common unitholders by the weighted average number of common units outstanding during the period increased by the number of additional common units that would have been outstanding if the potentially dilutive units had been issued.

Basic income (loss) per common unit and diluted income (loss) per common unit are the same for the years ended December 31, 2002 and 2001, as the number of potentially dilutive units were so small as not to cause the diluted earnings per unit to be different from the basic earnings per unit.

Comprehensive Income

Our comprehensive income is determined based on net income (loss), adjusted for changes in accumulated other comprehensive income (loss) from our cash flow hedging activities associated with our GulfTerra Alabama Intrastate operations, our Indian Basin processing plant, the San Juan assets and our unconsolidated affiliate, Poseidon Oil Pipeline Company, L.L.C.

The following table presents our allocation of accumulated other comprehensive loss as of December 31:

	2003	2002	2001
Common units' interest	$(7,488)	$(4,623)	$(1,259)
Series C units' interest	$(1,409)	$ (942)	$ --
General partner's interest	$ (130)	$ (57)	$ (13)

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 years ending December 31, 2003, 2002 and 2001, 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 SFAS No. 123, Accounting for Stock-Based Compensation, to account for all of our other stock-based compensation programs.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure. This statement amends SFAS No. 123, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the methods of accounting for stock-based employee compensation and the effect of the method used on reported results. This statement is effective for fiscal years ending after December 15, 2002. We have decided that we will continue to use APB No. 25 to value our stock-based compensation 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 and will include data providing the pro forma income effect of using the fair value method as required by SFAS No. 148. We will continue to use the provisions of SFAS No. 123 to account for all of our other stock-based compensation programs.

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

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS)		
Net income, as reported	$163,139	$97,688	$55,149
Add: Stock-based employee compensation expense included in reported net income	1,489	1,168	367
Less: Stock-based employee compensation expense determined under fair value based method	1,532	1,912	678
Pro forma net income	$163,096	$96,944	$54,838
Pro forma net income allocated to common unitholders	$ 66,452	$38,616	$12,949
Earnings per common unit:			
Basic, as reported	$ 1.33	$ 0.92	$ 0.38
Basic, pro forma	$ 1.33	$ 0.90	$ 0.38
Diluted, as reported	$ 1.32	$ 0.92	$ 0.38
Diluted, pro forma	$ 1.32	$ 0.90	$ 0.38

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

Accounting for Debt Extinguishments

In January 2003, we adopted SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.

Accordingly, we now evaluate the nature

of any debt extinguishments to determine whether to report any gain or loss resulting from the early extinguishment of debt as an extraordinary item or as a component of income from continuing operations.

Accounting for Costs Associated with Exit or Disposal Activities

In January 2003, we adopted SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities. This statement impacts any exit or disposal activities that we initiate after January 1, 2003 and we now recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Our adoption of this pronouncement did not have an effect on our financial position or results of operations.

Accounting for Guarantees

In accordance with the provisions of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, we record a liability at fair value, or otherwise disclose, certain guarantees issued after December 31, 2002, that contractually require us to make payments to a guaranteed party based on the occurrence of certain events. We have not entered into any material guarantees that would require recognition under FIN No. 45.

Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. This statement provides guidance on the classification of financial instruments, as equity, as liabilities, or as both liabilities and equity. The provisions of SFAS No. 150 are effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning July 1, 2003. We adopted the provisions of SFAS No. 150 on July 1, 2003, and our adoption had no material impact on our financial statements.

New Accounting Pronouncements Issued But Not Yet Adopted

Consolidation of Variable Interest Entities

In January 2003, the FASB issued FIN No. 46, Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51. 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. This standard requires a company to consolidate a VIE if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. In December 2003, the FASB issued FIN 46-R, which amended FIN No. 46, to extend its effective date until the first quarter of 2004 for all types of entities except special purpose entities (SPE's). In addition, FIN No. 46-R also limited the scope of FIN No. 46 to exclude certain joint ventures of other entities that meet the characteristics of businesses.

We have no SPE's as defined by FIN Nos. 46 and 46-R. We have evaluated our joint ventures, unconsolidated subsidiaries and other contractual arrangements that could be considered variable interests or variable interest entities that were created before February 1, 2003 and have determined that they will not have a significant effect on our reported results and financial position when we adopt the provisions of FIN No. 46-R in the first quarter of 2004.

2. ACQUISITIONS AND DISPOSITIONS

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. The general partner of the combined partnership will be jointly owned by affiliates of El Paso Corporation and privately-held Enterprise Products Company, with each owning a 50-percent interest. The definitive agreements include three transactions, of which two affect us.

In the first transaction that effects us, which occurred with the signing of the merger agreement, a wholly owned subsidiary of Enterprise purchased a 50 percent limited-voting interest in our general partner. This interest entitles Enterprise to half of the cash distributed to our general partner, but does not allow Enterprise to elect any of our general partner's directors or otherwise generally participate in our general partner's management of our business.

The second transaction that affects us will occur at the merger date. At the closing of the merger, each outstanding GulfTerra common unit (other than those owned by Enterprise) will convert into 1.81 Enterprise common units, GulfTerra will become a wholly-owned subsidiary of Enterprise, and El Paso Corporation will acquire a 50 percent interest in Enterprise's general partner (including the right to elect half of the directors of Enterprise's general partner). The closing of the merger is subject to the satisfaction of specified conditions, including obtaining clearance under the Hart-Scott-Rodino Antitrust Improvement Acts, and the approval of our unitholders and Enterprise's unitholders. Completion of the merger is expected to occur during the second half of 2004.

Our merger agreement with Enterprise limits our ability to raise additional capital prior to the closing of the merger without Enterprise's approval. In addition, because the closing of the merger will be a change of control, and thus a default, under our credit facility, we will either repay or amend that facility prior to the closing. In addition, because the merger closing will constitute a change of control under our indentures, 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 close of the merger. 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 is in place.

If the merger agreement is terminated and (1) a business transaction between us and a third party that conflicts with the merger was proposed and certain other conditions were met or (2) we materially and willfully violated our agreement not to solicit transactions that conflict with the merger, then we will be required to pay Enterprise a termination fee of $112 million. If the merger agreement is terminated because our unitholders did not approve the merger and either (1) a possible business transaction involving us but not involving Enterprise and conflicting with the merger was publicly proposed and our board of directors publicly and timely reaffirmed its recommendations of the Enterprise merger or (2) no such possible business transaction was publicly announced, then we will be required to pay Enterprise a termination fee of $15 million. Enterprise is subject to similar termination fee requirements.

Exchange with El Paso Corporation

In connection with our November 2002 San Juan assets acquisition, El Paso Corporation retained the obligation to repurchase the Chaco plant from us for $77 million in October 2021. In October 2003, we released El Paso Corporation from that obligation in exchange for El Paso Corporation contributing specified communication assets and other rights to us. The communication assets we received are used in the operation of our pipeline systems. Prior to the October 2003 exchange, we had access to these assets under our general and administrative services agreement with El Paso Corporation. We recorded the communication assets at El Paso Corporation's book value of $23.3 million with the offset to partners' capital.

As a result of the October 2003 exchange, we revised our estimate for the depreciable life of the Chaco plant from 19 to 30 years, the estimated remaining useful life of the Chaco plant. Depreciation expense will decrease approximately $0.5 million and $2.3 million on a quarter and annual basis.

Cameron Highway Oil Pipeline Company

Refer to Note 3 for a discussion related to our sale of a 50 percent interest in Cameron Highway Oil Pipeline.

San Juan Assets

In November 2002, we acquired from subsidiaries of El Paso Corporation, interests in assets we collectively refer to as the San Juan assets, which consist of the following:

- 100 percent of El Paso Field Services' San Juan Gathering and Processing Businesses, which include a natural gas gathering system and related compression facilities, the Rattlesnake Treating Plant, a 50-percent equity interest in Coyote Gas Treating, L.L.C. which owns the Coyote natural gas treating facility, and the remaining interests in the Chaco cryogenic natural gas processing plant we did not already own, all of which are located in the San Juan Basin of northwest New Mexico and southwestern Colorado;

- 100 percent of the Typhoon Oil Pipeline assets located in the Deepwater Trend area of the Gulf of Mexico. Typhoon Oil was placed in service in July 2001 and provides transportation of oil produced from the Typhoon field for delivery to a platform in Green Canyon Block 19 with onshore access through various oil pipelines;

- 100 percent of the Typhoon Gas Pipeline, which was placed in service in August 2001. Typhoon Gas is also located in the Deepwater Trend area of the Gulf of Mexico. The pipeline gathers natural gas from the Typhoon field for redelivery into El Paso Corporation's ANR Patterson System; and

- 100 percent of the Coastal Liquids Partners' NGL Business, consisting of an integrated set of NGL assets that stretch from the Mexico border near McAllen, Texas, to Houston, Texas. This business includes a fractionation facility near Houston, Texas; a truck-loading terminal near McAllen, Texas, and leased underground NGL storage facilities.

We purchased the San Juan assets for $782 million, $764 million after adjustments for capital expenditures and actual working capital acquired. During 2003, the total purchase price and net assets acquired decreased $2.4 million due to post-closing purchase price adjustments related to natural gas imbalances, NGL in-kind reserves and well loss reserves. We financed the purchase of these assets with net proceeds from an offering of $200 million of 10 5/8% Senior Subordinated Notes due 2012; borrowings of $237.5 million under our senior secured acquisition term loan; our issuance, to El Paso Corporation, of 10,937,500 of our Series C units valued at $32 per unit or $350 million; and currently available funds. We acquired the San Juan assets because they are strategically located in active supply development areas and are supported by long-term contracts that provide us with growing and reliable cash flows consistent with our stated growth strategy.

In connection with this acquisition, we entered into an agreement with El Paso Corporation under which El Paso Corporation would have been required, subject to specified conditions, to repurchase the Chaco plant from us for $77 million in October 2021, at which time we would have had the right to lease the plant from them for a period of 10 years with the option to renew the lease annually thereafter. In October 2003, we released El Paso Corporation from that repurchase obligation in exchange for El Paso Corporation contributing communication assets to us.

As a result of our acquisition of the San Juan assets, our financial results from the operation of the Chaco plant are significantly different from our results prior to the purchase in the following ways:

- We no longer receive fixed fee revenue of $0.134/Dth for natural gas processed; rather, from a majority of our customers, we receive a processing fee of an in-kind portion of the NGL produced from the natural gas processed. We then sell these NGL and, accordingly, our processing revenues are affected by changes in the price of NGL.

- We no longer receive revenue for leasing the Chaco plant to El Paso Field Services.

- We no longer recognize amortization expense relating to our investment in processing agreement, which we terminated upon completing the acquisition. This decrease in amortization expense is offset by additional depreciation expense associated with the acquired assets.

In accordance with our procedures for evaluating and valuing material acquisitions with El Paso Corporation, our Audit and Conflicts Committee engaged independent financial advisors. Separate financial advisors delivered fairness opinions for the acquisition of the San Juan assets and the issuance of the Series C units. Based on these opinions, our Audit and Conflicts Committee and the full Board approved these transactions.

The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed at November 27, 2002. Our allocation among the assets acquired is based on the results of an independent third-party appraisal.

	AT NOVEMBER 27, 2002 (IN THOUSANDS)
Note receivable	$ 17,100
Property, plant and equipment	763,696
Intangible assets	470
Investment in unconsolidated affiliate	2,500
Total assets acquired	783,766
Imbalances payable	17,403
Other current liabilities	2,565
Total liabilities assumed	19,968
Net assets acquired	$763,798

The acquired intangible assets represent contractual rights we obtained under dedication and transportation agreements with producers which we are amortizing to expense over the life of the contracts of approximately 4 years. We recorded adjustments to the purchase price of approximately $18 million primarily for capital expenditures and actual working capital acquired.

Our consolidated financial statements include the results of operations of the San Juan assets from the November 27, 2002 purchase date. We have included the assets and operating results of the El Paso Field Services' San Juan Gathering and Processing Businesses and the Typhoon Gas Pipeline in our natural gas pipelines and plants segment and the assets and operating results of the Typhoon Oil Pipeline and Coastal Liquids Partners' NGL Business in our oil and NGL logistics segment from the purchase date. The following selected unaudited pro forma financial information presents our consolidated operating results for the years ended December 31, 2002 and 2001 as if we acquired the San Juan assets on January 1, 2001:

	2002	2001
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)	
Operating revenues	$627,191	$427,942
Income from continuing operations	$ 88,902	$ 77,219
Income allocated to common unitholders from continuing operations	$ 25,738	$ 16,687
Basic and diluted net income per unit from continuing operations	$ 0.60	$ 0.43

The unaudited pro forma financial information presented above is not necessarily indicative of the results of operations we might have realized had the transaction been completed at the beginning of the earliest period presented, nor do they necessarily indicate our consolidated operating results for any future period.

EPN Holding Assets

In April 2002, we acquired, through a series of related transactions, from subsidiaries of El Paso Corporation the following midstream assets located in Texas and New Mexico, which we collectively refer to, for purposes of these financial statements, as the EPN Holding assets:

- The Waha natural gas gathering and treating system and the Carlsbad natural gas gathering system which are generally located in the Permian Basin region of Texas and New Mexico.

- A 50 percent undivided interest in the Channel Pipeline System, an intrastate natural gas transmission system located along the Gulf Coast of Texas.

- The TPC Offshore pipeline system, a collection of natural gas gathering and transmission assets located offshore of Matagorda Bay, Texas, including the Oyster Lake and MILSP Condensate Separation and Stabilization facilities and other undivided interests in smaller pipelines.

- GulfTerra Texas Pipeline, L.P. which owned, among other assets, (i) the GulfTerra Texas intrastate pipeline system, (ii) the TGP natural gas lateral pipelines, (iii) the leased natural gas storage facilities located in Wharton County, Texas generally known as the Wilson Storage facility, (iv) an 80 percent undivided interest in the East Texas 36 inch pipeline, (v) a 50 percent undivided interest in the West Texas 30 inch pipeline, (vi) a 50 percent undivided interest in the North Texas 36 inch pipeline, (vii) the McMullen County natural gas gathering system, (viii) the Hidalgo County natural gas gathering system, (ix) a 22 percent undivided interest in the Bethel-Howard pipeline, and (x) a 75 percent undivided interest in the Longhorn pipeline.

- El Paso Hub Services L.L.C. which owned certain contract rights and parcels of real property located in Texas.

- 100 percent of the outstanding joint venture interest in Warwink Gathering and Treating Company which owned, among other assets, the Warwink natural gas gathering system located in the Permian Basin region of Texas and New Mexico.

In conjunction with the acquisition of the above assets, we obtained from another affiliate of El Paso Corporation, all of the equity interest in El Paso Indian Basin, L.P. which owned a 42.3 percent undivided, non-operating interest in the Indian Basin natural gas processing plant and treating facility located in southeastern New Mexico and the price risk management activities associated with the plant.

We acquired the EPN Holding assets to provide us with a significant new source of cash flow, greater diversification of our midstream asset base and to provide new long term internal growth opportunities in the Texas intrastate market. We purchased the EPN Holding assets for $750 million, adjusted for the assumption

of $15 million of net working capital obligations related to natural gas imbalances resulting in net consideration of $735 million comprised of the following:

- $420 million of cash;

- $119 million of assumed short-term indebtedness payable to El Paso Corporation, which we subsequently repaid;

- $6 million in common units; and

- $190 million in assets, comprised of our Prince TLP and our nine percent overriding royalty interest in the Prince field (see discussion below).

During 2003, the purchase price and net assets acquired increased $17.5 million due to post-closing purchase price adjustments related primarily to a reduction in natural gas imbalance payables assumed in the transaction.

We entered into a limited recourse credit agreement with a syndicate of commercial banks to finance substantially all of the cash consideration associated with this transaction. See Note 6 for additional discussion regarding the EPN Holding term credit facility.

The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed at April 8, 2002. Our allocation among the assets acquired is based on the results of an independent third-party appraisal.

	AT APRIL 8, 2002
	(IN THOUSANDS)
Current assets	$ 4,690
Property, plant and equipment	780,648
Intangible assets	3,500
Total assets acquired	788,838
Current liabilities	15,229
Environmental liabilities	21,136
Total liabilities assumed	36,365
Net assets acquired	$752,473

The acquired intangible assets represent contractual rights we obtained under dedication and transportation agreements with producers which we will amortize to expense using the units-of-production method over the expected lives of the underlying reserves ranging from 26 to 45 years. Additionally, we assumed environmental liabilities of $21.1 million for estimated environmental remediation costs associated with the GulfTerra Texas intrastate pipeline assets as discussed in Note 11.

Our consolidated financial statements include the results of operations of the EPN Holding assets from the April 8, 2002 purchase date. We have included the assets and operating results of the Waha, Carlsbad and Warwink natural gas gathering systems; the Channel and TPC Offshore pipeline systems; and the GulfTerra Texas pipeline assets (excluding the Wilson Storage facility) in our natural gas pipelines and plants segment. Our 42.3 percent ownership interest in the assets and operating results of the Indian Basin plant are included in our oil and NGL logistics segment and the Wilson storage facility assets and operating results are included in our natural gas storage segment. The following selected unaudited pro forma information depicts our consolidated results of operations for the years ended December 31, 2002 and 2001 as if we acquired the EPN Holding assets on January 1, 2001:

	2002	2001
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)	
Operating revenues	$540,154	$538,095
Income from continuing operations	$114,517	$ 81,022
Income allocated to common unitholders from continuing operations	$ 56,020	$ 38,874
Basic and diluted net income per unit from continuing operations	$ 1.31	$ 1.13

The unaudited pro forma financial information presented above is not necessarily indicative of the results of operations we might have realized had the transaction been completed at the beginning of the earliest period presented, nor do they necessarily indicate our consolidated operating results for any future period.

Prince Assets

In connection with our April 2002 acquisition of the EPN Holding assets from El Paso Corporation, we sold our Prince tension leg platform (TLP) and our nine percent overriding royalty interest in the Prince Field to subsidiaries of El Paso Corporation. The results of operations for these assets have been accounted for as discontinued operations and have been excluded from continuing operations for all periods in our consolidated statements of income. Accordingly, the segment results in Note 15 reflect neither the results of operations for the Prince assets nor the related net assets held for sale. The Prince TLP was previously included in the platform services segment and related royalty interest was included in non-segment activity. Included in income from discontinued operations for the years ended December 31, 2002 and 2001 were revenues of $7.8 million and $8.8 million attributable to these disposed assets.

In April 2002, we sold the Prince assets for $190 million and recognized a gain on the sale of $0.4 million during 2002. In conjunction with this transaction, we repaid the related outstanding $95 million principal balance under our Argo term loan.

Deepwater Holdings L.L.C. and Chaco Transaction

In October 2001, we acquired the remaining 50 percent interest that we did not already own in Deepwater Holdings for approximately $81 million, consisting of $26 million cash and $55 million of assumed indebtedness, and at the acquisition date also repaid all of Deepwater Holdings' $110 million of indebtedness. HIOS and East Breaks became indirect wholly-owned assets through this transaction. In a separate transaction, we acquired interests in the title holder of, and other interests in the Chaco cryogenic natural gas processing plant for $198.5 million. The total purchase price was composed of a payment of $77 million to acquire the plant from the bank group that provided the financing for the construction of the facility and a payment of $121.5 million to El Paso Field Services in connection with the execution of a 20-year fee-based processing agreement relating to the processing capacity of the Chaco plant and dedication of natural gas gathered by El Paso Field Services to the Chaco plant. Under the terms of the processing agreement, we received a fixed fee for each dekatherm of natural gas that we processed at the Chaco plant, and we bore all costs associated with the plant's ownership and operations. El Paso Field Services personnel continued to operate the plant. In accordance with the original construction financing agreements, the Chaco plant was under an operating lease to El Paso Field Services. El Paso Field Services had the right to repurchase the Chaco plant at the end of the lease term in October 2002 for approximately $77 million. We funded both of these transactions by borrowing from our revolving credit facility. We accounted for these transactions as purchases and have assigned the purchase price to the net assets acquired based upon the estimated fair value of the net assets as of the acquisition date. The operating results associated with Deepwater Holdings are included in earnings from unconsolidated affiliates for the periods prior to October 2001. We have included the operating results of Deepwater Holdings and the Chaco plant in our consolidated financial statements from the acquisition date.

Since the Chaco transaction was an asset acquisition, we have assigned the total purchase price to property, plant and equipment and investment in processing agreement. Since the Deepwater Holdings transaction was an acquisition of additional interests in a business, we are providing summary information related to the acquisition of Deepwater Holdings in the following table (in thousands):

Fair value of assets acquired	$ 81,331
Cash acquired	5,386
Fair value of liabilities assumed	(60,917)
Net cash paid	$ 25,800

In connection with our acquisition of the San Juan assets in November 2002, the original terms of the processing, lease and operating agreements between the Chaco plant and El Paso Field Services were terminated. The effect on our operation of the Chaco plant resulting from our acquisition of the San Juan assets is discussed above.

GTM Texas (formerly EPN Texas)

In February 2001, we acquired GTM Texas from a subsidiary of El Paso Corporation for $133 million. We funded the acquisition of these assets by borrowing from our revolving credit facility. These assets include more than 500 miles of NGL gathering and transportation pipelines. The NGL pipeline system gathers and transports unfractionated and fractionated products. We also acquired three fractionation plants with a capacity of approximately 96 MBbls/d. These plants fractionate NGL into ethane, propane, butane and natural gasoline products that are used by refineries and petrochemical plants along the Texas Gulf Coast. We accounted for the acquisition as a purchase and assigned the purchase price to the assets acquired based upon the estimated fair value of the assets as of the acquisition date. We have included the operating results of GTM Texas in our consolidated financial statements from the acquisition date.

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the year ended December 31, 2001, as if we acquired GTM Texas, the Chaco plant and the remaining 50 percent interest in Deepwater Holdings on January 1, 2001:

	2001 (IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)
Operating revenues	$269,681
Operating income	$101,406
Net income allocated to limited partners	$ 39,157
Basic and diluted net income per unit	$ 1.14

Gulf of Mexico Assets

In accordance with an FTC order related to El Paso Corporation's merger with The Coastal Corporation, we, along with Deepwater Holdings, agreed to sell several of our offshore Gulf of Mexico assets to third parties in January 2001. Total consideration received for these assets was approximately $163 million consisting of approximately $109 million for the assets we sold and approximately $54 million for the assets Deepwater Holdings sold. The offshore assets sold include interests in Stingray, UTOS, Nautilus, Manta Ray Offshore, Nemo, Tarpon, and the Green Canyon pipeline assets, as well as interests in two offshore platforms and one dehydration facility. We recognized net losses from the asset sales of approximately $12 million, and Deepwater Holdings recognized losses of approximately $21 million. Our share of Deepwater Holdings' losses was approximately $14 million, which has been reflected in earnings from unconsolidated affiliates in the accompanying 2001 consolidated statement of income.

As additional consideration for the above transactions, El Paso Corporation agreed to make payments to us totaling $29 million. These payments were made in quarterly installments of $2.25 million for three years beginning in 2001 and we will receive the final payment of $2 million in the first quarter of 2004. From this additional consideration, we realized income of approximately $25 million in the first quarter of 2001, which has been reflected in other income in the accompanying 2001 consolidated statement of income.

3. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. As of December 31, 2003, the carrying amount of our equity investments exceeded the underlying equity in net assets by approximately $3.0 million, which is included in our oil and NGL logistics segment. With our adoption of SFAS No. 142 on January 1, 2002, we no longer amortize this excess amount, refer to Note 1, Summary of Significant Accounting Policies, Goodwill and Other Intangible Assets. Summarized financial information for these investments is as follows:

AS OF OR FOR THE YEAR ENDED
DECEMBER 31, 2003 ------------

-------------- DEEPWATER
CAMERON COYOTE GATEWAY(C)
HIGHWAY(C) POSEIDON TOTAL ----
--- ---------- ---------- ----
------ ------- (IN THOUSANDS)
END OF PERIOD OWNERSHIP
INTEREST.......................
50% 50% 50% 36% =======
======== ======== ==========
OPERATING RESULTS DATA:
Operating
revenues............. $ 7,200
$ -- $ -- $ 41,293 Other
income................... 7 47
37 56 Operating
expenses............. (355) --
-- (3,694)
Depreciation..................
(1,381) -- -- (8,316) Other
expenses.................
(736) (31) (171) (6,313) -----
-- -------- -------- ---------
- Net income
(loss).............. $ 4,735 $
16 $ (134) $ 23,026 =======
======== ======== ==========
OUR SHARE: Allocated income
(loss)........ $ 2,368 $ 8 $
(67) $ 8,289
Adjustments(a).................
9 (8) 67 (191) ------- -------
- -------- ---------- Earnings
from unconsolidated
affiliate................... $
2,377 $ -- $ -- $ 8,098
$11,373(b) ======= ========
======== ========== =======
Allocated
distributions........ $ 3,500
$ -- $ -- $ 8,640 $12,140
======= ======== ========
========== ======= FINANCIAL
POSITION DATA: Current
assets.................. $ 987
$ 8,271 $ 53,644 $ 98,937
Noncurrent
assets.............. 31,897
230,825 266,554 218,893
Current

liabilities............ 34,784
18,294 26,332 91,146
Noncurrent
liabilities......... --
155,000 125,000 123,000

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

(b) Total earnings from unconsolidated affiliates includes a $898 thousand gain associated with the sale of our interest in Copper Eagle.

(c) Cameron Highway Oil Pipeline Company and Deepwater Gateway, L.L.C. are development stage companies; therefore there are no operating revenues or operating expenses to provide operational results. Since their formations, they have incurred organizational expenses and received interest income.

Cameron Highway. In June 2003, we formed Cameron Highway Oil Pipeline Company and contributed to this newly formed company the $458 million Cameron Highway oil pipeline system construction project. Cameron Highway is responsible for building and operating the pipeline, which is scheduled for completion during the fourth quarter of 2004. We entered into producer agreements with three major anchor producers, BP Exploration & Production Company, BHP Billiton Petroleum (Deepwater), Inc., and Union Oil Company of California, which agreements were assigned to and assumed by Cameron Highway. The producer agreements require construction of the 390-mile Cameron Highway oil pipeline.

In July 2003, we sold a 50 percent interest in Cameron Highway to Valero Energy Corporation for $86 million, forming a joint venture with Valero. Valero paid us approximately $70 million at closing, including $51 million representing 50 percent of the capital investment expended through that date for the pipeline project. In July 2003, we recognized $19 million as a gain from the sale of long-lived assets. In addition, Valero will pay us $5 million once the system is completed and another $11 million by the end of 2006. We expect to reflect the receipts of these additional amounts in the periods received as gains from the sale of long-lived assets in our statement of income. In connection with the formation of the Cameron Highway joint venture, Valero agreed to pay their proportionate share of pipeline construction costs that exceed Cameron Highway's capital resources, including the initial equity contributions and proceeds from Cameron Highway's project loan facility.

The Cameron Highway oil pipeline system project is expected to be funded with 37 percent equity, or $169 million through capital contributions from us and Valero, the two Cameron Highway partners, which contributions have already been made, and 63 percent debt through a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes. See Note 6 for additional discussion of the project loan facility. As of December 31, 2003, Cameron Highway has spent approximately $256 million (of which $85 million constituted equity contributions by us) related to this pipeline, which is in the construction stage. We and Valero are obligated to make additional capital contributions to Cameron Highway if and to the extent that the construction costs for the pipeline exceed Cameron Highway's capital resources, including initial equity contributions and proceeds from Cameron Highway's project loan facility.

Deepwater Gateway. As of December 31, 2003, we have contributed $33 million, as our 50 percent share, to Deepwater Gateway, which amount satisfies our initial equity funding requirement related to the Marco Polo TLP. We expect that the remaining costs associated with the Marco Polo TLP will be funded through the $155 million project finance loan and Deepwater Gateway's members' contingent equity obligations (of which our share is $14 million). This project finance loan will mature in July 2004 unless construction is completed before that time and Deepwater Gateway meets other specified conditions, in which case the project finance loan will convert into a term loan with a final maturity date of July 2009. The loan agreement requires Deepwater Gateway to maintain a debt service reserve equal to six months' interest. Other than that debt service reserve and any other reserve amounts agreed upon by more than 66.7 percent majority interest of Deepwater Gateway's members, Deepwater Gateway will (after the project finance loan is either repaid or converted into a term loan) distribute any available cash to its members quarterly. Deepwater Gateway is not currently generating income or cash flow. Deepwater Gateway is managed by a management committee consisting of representative from each of its members.

Front Runner Oil Pipeline. In September 2003, we announced that Poseidon, our 36 percent owned joint venture, entered into an agreement for the purchase and sale of crude oil from the Front Runner Field. Poseidon will construct, own and operate the $28 million project, which will connect the Front Runner platform with Poseidon's existing system at Ship Shoal Block 332. The new 36-mile, 14-inch pipeline is expected to be operational by the third quarter of 2004 and have a capacity of 65 MBbls/d. As Poseidon expects to fund Front Runner's capital expenditures from its operating cash flow and from its revolving credit facility, we do not expect to receive distributions from Poseidon until the Front Runner oil pipeline is completed.

	AS OF OR FOR THE YEAR ENDED DECEMBER 31, 2002			
	COYOTE(A)	POSEIDON	DEEPWATER GATEWAY(B)	TOTAL
	(IN THOUSANDS)			
END OF PERIOD OWNERSHIP INTEREST	50%	36%	50%	
OPERATING RESULTS DATA:				
Operating revenues	$ 635	$ 54,261	$ --	
Other income	2	26,695	20	
Operating expenses	(38)	(4,691)	--	
Depreciation	(110)	(8,356)	--	
Other expenses	(75)	(6,923)	(234)	
Net income (loss)	$ 414	$ 60,986	$ (214)	
OUR SHARE:				
Allocated income (loss)	$ 207	$ 21,955	$ (107)	
Adjustments(c)	(13)	(8,510)	107	
Earnings from unconsolidated affiliate	$ 194	$ 13,445	$ --	$13,639
Allocated distributions	$ 2,000	$ 15,804	$ --	$17,804
FINANCIAL POSITION DATA:				
Current assets	$ 1,575	$ 152,784	$ 10,745	
Noncurrent assets	33,349	218,463	110,309	
Current liabilities	34,559	119,974	28,268	
Noncurrent liabilities	--	148,000	27,000	

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(a) We acquired an interest in Coyote Gas Treating, L.L.C. in November 2002 as part of the San Juan assets acquisition.

(b) In June 2002, we formed Deepwater Gateway, L.L.C., a 50/50 joint venture with Cal Dive International, Inc., to construct and install the Marco Polo TLP. Also in August 2002, Deepwater Gateway obtained a project finance loan to fund a substantial portion of the cost to construct the Marco Polo TLP. For further discussion of this project loan, see Note 6, Financing Transactions. Deepwater Gateway, L.L.C. is a development stage company; therefore there are no operating revenues or operating expenses to provide operational results. Since Deepwater Gateway's formation in 2002, it has incurred organizational expenses and received interest income.

(c) We recorded adjustments primarily for differences from estimated year end earnings reported in our Annual Report on our Form 10-K and actual earnings recorded in the audited annual reports of our unconsolidated affiliates. The adjustment for Poseidon primarily represents the receipt of proceeds from a favorable litigation related to the January 2000 pipeline rupture.

	AS OF OR FOR THE YEAR ENDED DECEMBER 31, 2001				
	DEEPWATER HOLDINGS(A)	POSEIDON	DIVESTED INVESTMENTS(B)	OTHER(C)	TOTAL
	(IN THOUSANDS)				
END OF PERIOD OWNERSHIP INTEREST	100%	36%	--	50%	
OPERATING RESULTS DATA:					
Operating revenues	$ 40,933	$ 70,401	$1,982	$145	
Other income (loss)	--	394	(85)	--	
Operating expenses	(16,740)	(1,586)	(590)	(73)	
Depreciation	(8,899)	(10,552)	(953)	--	
Other (expenses) income	(5,868)	(7,668)	222	(22)	
Loss on sale of assets	(21,453)	--	--	--	
Net income (loss)	$(12,027)	$ 50,989	$ 576	$ 50	
OUR SHARE:					
Allocated income (loss)(d)	$ (9,925)	$ 18,356	$ 148	$ 25	
Adjustments(e)	--	(146)	(9)	--	
Earnings (loss) from unconsolidated affiliates	$ (9,925)	$ 18,210	$ 139	$ 25	$ 8,449
Allocated distributions	$ 12,850	$ 22,212	$ --	$ --	$35,062
FINANCIAL POSITION DATA:					
Current assets		$ 91,367		$177	
Noncurrent assets		226,570		--	
Current liabilities		80,365		33	
Noncurrent liabilities		150,000		--	

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(a) In January 2001, Deepwater Holdings sold its Stingray and West Cameron subsidiaries. Deepwater Holdings sold its interest in its UTOS subsidiary in April 2001. In October 2001, we acquired the remaining 50 percent of Deepwater Holdings and as a result of this transaction, from the acquisition date Deepwater Holdings is consolidated in our financial statements. The information presented for Deepwater Holdings as an equity investment is through October 18, 2001.

(b) Divested Investments contains Manta Ray Offshore Gathering Company, L.L.C. and Nautilus Pipeline Company L.L.C. In January 2001, we sold our 25.67 percent interest in Manta Ray Offshore and our 25.67 percent interest in Nautilus.

(c) Through October 2001 this company processed gas for Deepwater Holdings' Stingray subsidiary. This agreement was terminated in October 2001, and as of this date there are no operations related to this investment.

(d) The income (loss) from Deepwater Holdings is not allocated proportionately with our ownership percentage because the capital contributed by us was a larger amount of the total capital at the time of formation. Therefore, we were allocated a larger amount of amortization of Deepwater Holdings' excess purchase price of its investments. Also, we were allocated a larger portion of Deepwater Holdings' $21 million loss incurred in 2001 due to the sale of Stingray, UTOS, and the West Cameron dehydration facility. Our total share of the losses relating to these sales was approximately $14 million.

(e) We recorded adjustments primarily for differences from estimated year end earnings reported in our Annual Report on Form 10-K and actual earnings reported in the audited annual reports of our unconsolidated affiliates.

4. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

	DECEMBER 31, 2003	DECEMBER 31, 2002
	(IN THOUSANDS)	
Property, plant and equipment, at cost(1)		
Pipelines	$2,487,102	$2,317,503
Platforms and facilities	121,105	128,582
Processing plants	305,904	300,897
Oil and natural gas properties	131,100	127,975
Storage facilities	337,535	331,562
Construction work-in-progress	383,640	177,964
	3,766,386	3,384,483
Less accumulated depreciation, depletion and amortization	871,894	659,545
Total property, plant and equipment, net	$2,894,492	$2,724,938

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(1) Includes leasehold acquisition costs with an unamortized balance of $3.2 million and $4.1 million at December 31, 2003 and 2002. 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 further guidance is provided.

Due to the sale of our interest in the Manta Ray Offshore system in January 2001, we lost a primary connecting point to our Manta Ray pipeline. As a result, we abandoned the Manta Ray pipeline and recorded an impairment of approximately $3.9 million in the first quarter of 2001 which is reflected in the natural gas pipelines and plants segment.

5. INVESTMENT IN PROCESSING AGREEMENT

As part of our October 2001 Chaco transaction, we paid $121.5 million to El Paso Field Services for a 20-year fee-based processing agreement. The processing agreement was being amortized on a straight-line basis over the life of the agreement and we recorded amortization expense of $5.6 million in 2002 and $1.5 million in 2001 related to this asset. As a result of the San Juan acquisition in November 2002, we now own the gathering system and related facilities previously owned by El Paso Field Services, including the rights of El Paso Field Services under the arrangements relating to the Chaco plant. As part of the San Juan acquisition, the processing agreement was terminated.

6. FINANCING TRANSACTIONS

CREDIT FACILITY

Our credit facility consists of two parts: the revolving credit facility maturing in 2006 and a senior secured term loan maturing in 2008. Our credit facility is guaranteed by us and all of our subsidiaries, except for our unrestricted subsidiaries, as detailed in Note 16, and are 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, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JPMorgan Chase Bank increased by 1.00%); or (ii) LIBOR. The interest rate we are charged is contingent upon our leverage ratio, as defined in our credit facility, and ratings we are assigned by S&P or Moody's. The interest we are charged would increase by 0.25% if the credit ratings on our senior secured credit facility decrease or our leverage ratio decreases, or, alternatively, would decrease by 0.25% if these ratings are increased or our leverage ratio improves. 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 restrict our ability to make distributions to our unitholders. The financial covenants associated with our credit facility are as follows:

(a) The ratio of consolidated EBITDA, as defined in our credit agreements, to consolidated interest expense cannot be less than 2.0 to 1.0;

(b) The ratio of consolidated total senior indebtedness on the last day of any fiscal quarter to the consolidated EBITDA for the four quarters ending on the last day of the current quarter cannot exceed 3.25 to 1.0; and

(c) The ratio of our consolidated total indebtedness on the last day of any fiscal quarter to the consolidated EBITDA for the four quarters ending on the last day of the current quarter cannot exceed 5.25 to 1.0.

Among other things, our credit agreement includes as an event of default a change of control, defined as the failure of El Paso Corporation and its subsidiaries to no longer own at least 50 percent of our general partner. We are in compliance with the financial ratios and covenants contained in each of our credit facilities at December 31, 2003.

Revolving Credit Facility

In September 2003, we renewed our revolving credit facility to, among other things, expand the credit available from $600 million to $700 million and extend the maturity from May 2004 to September 2006.

At December 31, 2003, we had $382 million outstanding under our revolving credit facility at an average interest rate of 3.17%. We may elect that all or a portion of the revolving credit facility bear interest at either the variable rate described above increased by 1.0% or LIBOR increased by 2.0%. The total amount available to us at December 31, 2003, under this facility was $318 million.

Senior Secured Term Loan

In December 2003, we refinanced the term loan portion of our credit facility to provide greater financial flexibility by, among other things, expanding the existing term component from $160 million to $300 million, extending the maturity from October 2007 to December 2008, reducing the semi-annual payments from $2.5 million to $1.5 million and reducing the interest rate we are charged by 1.25%. We used the proceeds from the term loan to repay the $155 million outstanding under the initial term loan and to temporarily reduce amounts outstanding under our revolving credit facility. We charged $2.8 million to interest and debt expense in December 2003 to write-off unamortized debt issuance costs associated with the initial term loan.

The senior secured term loan is payable in semi-annual installments of $1.5 million in June and December of each year for the first nine installments and the remaining balance at maturity in December 2008. We may elect that all or a portion of the senior secured term loan bear interest at either 1.25% over the variable base rate discussed above; or LIBOR increased by 2.25%. As of December 31, 2003, we had $300 million outstanding with an average interest rate of 3.42%.

GulfTerra Holding Term Credit Facility (formerly EPN Holding Term Credit Facility)

In connection with our acquisition of the EPN Holding assets from El Paso Corporation in April 2002, EPN Holding entered into a $560 million term credit facility with a group of commercial banks. The term credit facility provided a term loan (the GulfTerra Holding term loan) of $535 million to finance the acquisition of the EPN Holding assets, and a revolving credit facility (the GulfTerra Holding revolving credit facility) of up to $25 million to finance EPN Holding's working capital. At the time of its acquisition, EPN Holding borrowed $535 million ($531 million, net of issuance costs) under this term loan and had $25 million available under the GulfTerra Holding revolving credit facility. We used net proceeds of approximately $149 million from our April 2002 common unit offering, $0.6 million contributed by our general partner to maintain its one percent capital account balance and $225 million of the net proceeds from our May 2002 offering of 8 1/2% Senior Subordinated Notes to reduce indebtedness under the term loan. In July 2003, we repaid the remaining $160 million balance of this term credit facility with proceeds from our issuance of $250 million 6 1/4% senior notes due 2010. We recognized a loss of $1.2 million related to the write-off of unamortized debt issuance costs in connection with our repayment of this facility.

Senior Secured Acquisition Term Loan

As part of our November 2002 San Juan assets acquisition, we entered into a $237.5 million senior secured acquisition term loan to fund a portion of the purchase price. We repaid this senior secured acquisition term loan in March 2003 with proceeds from our issuance of $300 million 8 1/2% senior subordinated notes due 2010. We recognized a loss of $3.8 million related to the write-off of unamortized debt issuance costs in connection with our repayment of this facility. From the issuance of the senior secured acquisition term loan in November 2002 to its repayment date, the interest rates on our revolving credit facility and GulfTerra Holding term credit facility were 2.25% over the variable base rate described above or LIBOR increased by 3.50%.

Argo Term Loan

This loan with a balance of $95 million, including current maturities, at December 31, 2001, was repaid in full in April 2002, in connection with the EPN Holding assets acquisition.

SENIOR NOTES

In July 2003, we issued $250 million in aggregate principal amount of 6 1/4% senior notes due June 2010. We used the proceeds of approximately $245.1 million, net of issuance costs, to repay $160 million of indebtedness under the GulfTerra Holding term credit facility and to temporarily repay $85.1 million of the balance outstanding under our revolving credit facility. The interest on our senior notes is payable semi-annually in June and December with the principal maturing in June 2010. Our senior notes are unsecured obligations that rank senior to all our existing and future subordinated debt and equally with all of our existing and future senior debt, although they are effectively junior in right of payment to all of our existing and future senior secured debt to the extent of the collateral securing that debt. Our senior notes are guaranteed by us and all of our subsidiaries, except for our unrestricted subsidiaries.

We may redeem some or all of our senior notes, at our option, at any time with at least 30 days notice at a price equal to the greater of (1) 100 percent of the principal amount plus accrued interest, or (2) the sum of the present value of the remaining scheduled payments plus accrued interest.

SENIOR SUBORDINATED NOTES

Each issue of our senior subordinated notes is subordinated in right of payment to all of our existing and future senior debt, including our existing credit facility and the senior notes we issued in July 2003.

In March 2003, we issued $300 million in aggregate principal amount of 8 1/2% senior subordinated notes. The interest on these notes is payable semi-annually in June and December, and the notes mature in June 2010. We used the proceeds of approximately $293.5 million, net of issuance costs, to repay $237.5 million of indebtedness under our senior secured acquisition term loan and to temporarily repay $55.5 million of the balance outstanding under our revolving credit facility. We may, at our option, prior to June 1, 2006, redeem up to 33 percent of the originally issued aggregate principal amount of these notes at a redemption price of 108.50 percent of the principal amount, and in December 2003, we redeemed $45 million under this provision (see discussion below). We may redeem all or part of the remainder of these notes at any time on or after June 1, 2007. The redemption price on that date is 104.25 percent of the principal amount, declining annually until it reaches 100 percent of the principal amount.

In November 2002, we issued $200 million in aggregate principal amount of 10 5/8% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature in December 2012. These notes were issued for $198 million, net of discount of $1.5 million to yield 10.75% (proceeds of $194 million, net of issuance costs) which we used to fund a portion of the acquisition of the San Juan assets. We may, at our option, prior to December 1, 2005, redeem up to 33 percent of the originally issued aggregate principal amount of the notes at a redemption price of 110.625%, and in December 2003, we redeemed $66 million under this provision (see discussion below). On or after December 1, 2007, we may redeem all or part of the remainder of these notes at 105.313% of the principal amount.

In May 2002, we issued $230 million in aggregate principal amount of 8 1/2% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature June 2011. The Senior Subordinated Notes were issued for $234.6 million (proceeds of approximately $230 million, net of issuance costs). We used proceeds of $225 million to reduce indebtedness under our EPN Holding term credit facility and the remainder for general partnership purposes. We may, at our option, prior to June 1, 2004, redeem up to 33 percent of the originally issued aggregate principal amount of the senior subordinated notes due June 2011, at a redemption price of 108.500%, and in December 2003, we redeemed $75.9 million under this provision (see discussion below). On or after June 1, 2006, we may redeem all or part of the remainder of these notes at 104.250% of the principal amount.

In May 2001, we issued $250 million in aggregate principal amount of 8 1/2% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature in June 2011. Proceeds of approximately $243 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility. We may, at our option, prior to June 1, 2004, redeem up to 33 percent of the originally issued aggregate principal amount of the senior subordinated notes due June 2011, at a redemption price of 108.500%, and in December 2003, we redeemed $82.5 million under this provision (see discussion below). On or after June 1, 2006, we may redeem all or part of the remainder of these notes at 104.250% of the principal amount.

In May 1999, we issued $175 million in aggregate principal amount of 10 3/8% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature in June 2009. Proceeds of approximately $169 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility. On or after June 1, 2004, we may redeem all or part of these notes at 105.188% of the principal amount.

Our subsidiaries, except GulfTerra Energy Partners Finance Corporation and our unrestricted subsidiaries, have guaranteed our obligations under the senior notes and all of the issuances of senior subordinated notes described above. In addition, we could be required to repurchase the senior notes and senior subordinated notes if certain circumstances relating to change of control or asset dispositions exist.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million of our 8 1/2%

senior subordinated notes due 2011. With this swap agreement, we will pay the counterparty a LIBOR based interest rate plus a spread of 4.20% (which rate was 1.55% at December 31, 2003) and receive a fixed rate of 8 1/2%. We are accounting for this derivative as a fair value hedge under SFAS No. 133. At December 31, 2003, the fair value of the swap was a liability, included in non-current liabilities, of approximately $7.4 million. The fair value of the hedged debt decreased by the same amount.

In December 2003, we used a portion of the net proceeds from our October 2003 equity offerings to redeem approximately $269.4 million in principal amount of our senior subordinated notes. The terms of our indentures allow us to use proceeds from an equity offering, within a 90 day period after the offering, to redeem up to 33 percent of the principal during the first three years the notes are outstanding. We incurred additional costs totaling $29.1 million resulting from the payment of the redemption premiums and the write-off of unamortized debt issuance costs, premiums and discounts. We accounted for these costs as an expense during the fourth quarter of 2003 in accordance with the provisions of SFAS No. 145.

In March 2004, we gave notice to exercise our right, under the terms of our senior subordinated notes' indentures, to repay, at a premium, approximately $39.1 million in principal amount of those senior subordinated notes. The indentures provide that, within 90 days of an equity offering, we can call up to 33 percent of the original face amount at a premium. The amount we can repay is limited to the net proceeds of the offering. We will recognize additional costs totaling $4.1 million resulting from the payment of the redemption premiums and the writeoff of unamortized debt issuance costs. We will account for these costs as an expense during the second quarter of 2004 in accordance with the provisions of SFAS No. 145.

RESTRICTIVE PROVISIONS OF SENIOR AND SENIOR SUBORDINATED NOTES

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. 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.

OTHER CREDIT FACILITIES

Poseidon

As of December 31, 2003, 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.

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 under its credit facility at 3.49% through January 2004. Poseidon, under its credit facility, currently pays an additional 1.25% over the LIBOR rate resulting in an effective interest rate of 4.74% on the hedged notional amount. The interest rates Poseidon is charged on balances outstanding under its credit facility are dependent on its leverage ratio as defined in the Poseidon credit facility. Poseidon's interest rate at December 31, 2003 was LIBOR plus 1.25% for Eurodollar loans and a variable base rate equal to the greater of the prime rate or 0.50% plus the federal funds rate (as those terms are defined in the Poseidon credit agreement) plus 0.25% for Base Rate loans. As of December 31, 2003, the remaining $48 million was at an average interest rate of 2.46%.

Under its amended credit facility, based on Poseidon's leverage ratio for the year ended December 31, 2003, Poseidon's interest rate is LIBOR plus 2.00% for Eurodollar loans and a variable base rate equal to the greater of the prime rate or 0.50% plus the federal funds rate (as those terms are defined in the Poseidon credit agreement) plus 1.00% for Base Rate loans. Poseidon's interest rates will decrease by 0.25% if their leverage ratio declines to 3.00 to 1.00 or less, by 0.50% if their leverage ratio declines to 2.00 to 1.00 or less, or by 0.625% if their leverage ratio declines to 1.00 to 1.00 or less. Additionally, Poseidon pays commitment fees on the unused portion of the credit facility at rates that vary from 0.25% to 0.375%. This credit agreement requires Poseidon to maintain a debt service reserve equal to two times the previous quarters' interest.

Poseidon's credit agreement contains covenants such as restrictions on debt levels, restrictions on liens collateralizing debt and guarantees, restrictions on mergers and on the sales of assets and dividend restrictions. A breach of any of these covenants could result in acceleration of Poseidon's debt and other financial obligations.

Under the Poseidon $170 million revolving credit facility, the financial debt covenants are:

(a) Poseidon must maintain consolidated tangible net worth in an amount not less than $75 million plus 100% of the net cash proceeds from the issuance by Poseidon of equity securities of any kind;

(b) the ratio of Poseidon's EBITDA, as defined in Poseidon's credit agreement, to interest expense paid or accrued during the four quarters ending on the last day of the current quarter must be at least 2.50 to 1.00; and

(c) the ratio of total indebtedness of Poseidon to EBITDA for the four quarters ending on the last day of the current quarter shall not exceed 4.50 to 1.00 in 2004, 3.50 to 1.00 in 2005 and 3.00 to 1.00 thereafter.

Poseidon was in compliance with the above covenants and the covenants under its previous facility as of December 31, 2003.

Deepwater Gateway

In August 2002, Deepwater Gateway, our joint venture that is constructing the Marco Polo 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. Deepwater Gateway may elect that all or a portion of the project finance loan bear interest at either (i) LIBOR plus 1.75% or (ii) an alternate base rate (equal to the greater of the prime rate, the base CD rate plus 1% or the federal funds rate plus 0.5%, as those terms are defined in the project finance loan agreement) plus 0.75%. Deepwater Gateway must also pay commitment fees of 0.375% per year on the unused portion of the project finance loan. The loan is collateralized by substantially all of Deepwater Gateway's assets. If Deepwater Gateway defaults on its payment obligations under the project finance loan, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of December 31, 2003, Deepwater Gateway had $155 million outstanding under the project finance loan at an average interest rate of 2.94% and had not paid us or any of our subsidiaries any distributions.

This project finance loan will mature in July 2004 unless construction is completed before that time and Deepwater Gateway meets other specified conditions, in which case the project finance loan will convert into a term loan with a final maturity date of July 2009. Upon conversion of the project finance loan to a term loan, Deepwater Gateway will be required to maintain a debt service reserve of not less than the projected principal, interest and fees due on the term loan for the immediately succeeding six month period. In addition, Deepwater Gateway is prohibited from making distributions until the project finance loan has been repaid or is converted.

Cameron Highway

Cameron Highway Oil Pipeline Company (Cameron Highway), an unconsolidated affiliate in which we have a 50 percent joint venture ownership interest (See Note 3 for additional discussion relating to the formation of Cameron Highway), entered into a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes, each of which fund proportionately as construction costs are incurred.

The $225 million construction loan bears interest at Cameron Highway's option at each borrowing at either (i) 2.00% over the variable base rate (equal to the greater of the prime rate as determined by JPMorgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JPMorgan Chase Bank increased by 1.00%); or (ii) 3.00% over LIBOR. Upon completion of the construction, the construction loan will convert to a term loan maturing July 2008, subject to the terms of the loan agreement. At the end of the first quarter following the first anniversary of the conversion into a term loan, Cameron Highway will be required to make quarterly principal payments of $8.125 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by December 31, 2006, the construction loan and senior secured notes become fully due and payable. At December 31, 2003, Cameron Highway had $69 million outstanding under the construction loan at an average interest rate of 4.21%.

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 December 31, 2003, Cameron Highway had $56 million outstanding under the notes at an average interest rate of 7.38%.

Under the terms of its project loan facility, Cameron Highway must pay each of the lenders and the senior secured noteholders commitment fees of 0.5% per year on any unused portion of such lender's or noteholder's committed funds. The project loan facility as a whole is collateralized 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, as discussed in Note 3, 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 next 5 years and in total thereafter are as follows (in thousands):

2004	$ 3,000
2005	3,000
2006	385,000
2007	3,000
2008	288,000
Thereafter	1,135,600
Total long-term debt and other financing obligations, including current maturities	$1,817,600

INTEREST AND DEBT EXPENSE

We recognized the interest cost incurred in connection with our financing transactions as follows for each of the years ended December 31:

	2003	2002	2001
	(IN THOUSANDS)		
Interest expense incurred	$140,282	$87,522	$ 54,885
Interest capitalized	(12,452)	(5,571)	(11,755)
Net interest expense	127,830	81,951	43,130
Less: Interest expense on discontinued operations	--	891	1,588
Net interest expense on continuing operations	$127,830	$81,060	$ 41,542

LOSS DUE TO EARLY REDEMPTIONS OF DEBT

We recognized losses associated with early redemptions of debt as follows for each of the years ended December 31:

	2003	2002
	(IN THOUSANDS)	
Loss due to payment of redemption premiums	$24,302	$ --
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	12,544	2,434
	$36,846	$2,434

7. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The carrying amounts and estimated fair values of our financial instruments at December 31 are as follows:

	2003		2002	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	(IN MILLIONS)			
Liabilities:				
Revolving credit facility	$382.0	$382.0	$491.0	$491.0
GulfTerra Holding term credit facility	--	--	160.0	160.0
Senior secured term loan	300.0	300.0	160.0	160.0
Senior secured acquisition term loan	--	--	237.5	237.5
10 3/8% senior subordinated notes	175.0	189.9	175.0	186.4
8 1/2% senior subordinated notes(1)	167.5	188.4	250.0	233.1
8 1/2% senior subordinated notes(1)	156.6	173.4	234.3	214.5
10 5/8% senior subordinated notes	133.1	165.5	198.5	205.5
8 1/2% senior subordinated notes	255.0	290.7	--	--
6 1/4% senior notes	250.0	262.5	--	--
Non-trading derivative instruments				
Commodity				

swap and forward
contracts.......... $ 9.0 $ 9.0 $
4.7 $ 4.7 Interest rate
swap............................
7.4 7.4 -- --

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(1) Excludes market value of interest rate swap, see interest rate swap discussion below.

The notional amounts and terms of the financial instruments held for purposes other than trading were as follows at December 31:

	2003			2002		
	NOTIONAL VOLUME BUY	NOTIONAL VOLUME SELL	MAXIMUM TERM IN YEARS	NOTIONAL VOLUME BUY	NOTIONAL VOLUME SELL	MAXIMUM TERM IN YEARS
Commodity						
Natural Gas (MDth)....................	85	10,980	<1	95	10,950	<1
NGL (MBbl)............................	--	1,644	<1	--	--	--

In July 2003, 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 will pay the counterparty a LIBOR based interest rate plus a spread of 4.20% (which rate was 1.55% at December 31, 2003) and receive a fixed rate of 8 1/2%.

As of December 31, 2003, and 2002, our carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because the variable interest rates on these loans reprice frequently to reflect currently available interest rates. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. We estimated the fair value of all derivative financial instruments from prices indicated for the same or similar commodity transactions for a specific index.

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of our customers' failure to pay. Our customers are concentrated in the energy sector, and the creditworthiness of several industry participants have been called into question. We maintain credit policies to minimize overall credit risk. We monitor our exposure to and determine, as appropriate, whether we should request prepayments, letters of credit or other collateral from our counterparties.

8. PARTNERS' CAPITAL

General

As of December 31, 2003, we had 58,404,649 common units outstanding. Common units totaling 48,020,404 are owned by the public, representing an 82.2 percent common unit interest in us. As of December 31, 2003, El Paso Corporation, through its subsidiaries, owned 10,384,245 common units, or 17.8 percent of our outstanding common units, all of our 10,937,500 Series C units and 50 percent of our one percent general partner interest.

Offering of Common Units

During 2003, we issued the following common units in public offerings:

OFFERING DATE	COMMON UNITS ISSUED	PUBLIC OFFERING PRICE (PER UNIT)	NET OFFERING PROCEEDS (IN THOUSANDS)
October 2003...............................	4,800,000	$40.60	$186.1
August 2003................................	507,228	$39.43	$ 19.7
June 2003..................................	1,150,000	$36.50	$ 40.3
May 2003(1)................................	1,118,881	$35.75	$ 38.3
April 2003.................................	3,450,000	$31.35	$103.1

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(1) Offering includes 80 Series F convertible units offered. Refer to description below.

In addition to our public offerings of common units, in October 2003, we sold 3,000,000 common units privately to Goldman Sachs in connection with their purchase of a 9.9 percent membership interest in our general partner. We used the net proceeds of $111.5 million from that private sale and the net proceeds from the other common unit public offerings to temporarily reduce amounts outstanding under our revolving credit facility, senior subordinated notes, and for general partnership purposes.

In May 2003, we issued 1,118,881 common units and 80 Series F convertible units in a registered offering to a large institutional investor for approximately $38.3 million net of offering costs. Our Series F convertible units are not listed on any securities exchange or market. Each Series F convertible unit is comprised of two separate detachable units -- a Series F1 convertible unit and a Series F2 convertible unit -- that have identical terms except for vesting and termination dates and the number of underlying common units into which they may be converted. 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. The Series F2 units terminate on 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 of (i) 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 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 December 31, 2003 and March 2, 2004, was $40.38 and $39.40. The Series F convertible units may be converted into a maximum of 8,329,679 common units. Holders of Series F convertible units are not entitled to vote or receive distributions. The $4.1 million value associated with the Series F convertible units 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 $26.00 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 December 31, 2003.

In the first quarter of 2004, 45 Series F1 convertible units were converted into 1,146,418 common units, for which the holder of the convertible units paid us $45 million.

Any Series F 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.

In connection with the offerings in 2003, our general partner contributed to us approximately $2.0 million of our Series B preference units and cash of $3.1 million in order to maintain its one percent general partner interest.

In April 2002, we completed simultaneous offerings of 4,083,938 common units, which included a public offering of 3,000,000 common units and a private offering, at the same unit price, of 1,083,938 common units to our general partner (pursuant to our general partner's anti-dilution rights under our partnership agreement) as a transaction not involving a public offering. We used the net cash proceeds of approximately $149 million to reduce indebtedness under EPN Holding's term credit facility. Also in April 2002, we issued in a private offering 159,497 common units at the then-current market price of $37.74 per unit to a subsidiary of El Paso Corporation as partial consideration for our acquisition of the EPN Holding assets. In addition, our general partner contributed approximately $0.6 million in cash to us in April 2002 in order to maintain its one percent capital account balance.

In October 2001, we completed simultaneous offerings of 5,627,070 common units, which included a public offering of 4,150,000 common units and a private offering, at the same unit price, of 1,477,070 common units to our general partner (pursuant to our general partner's anti-dilution rights under our partnership agreement) as a transaction not involving a public offering. We used the net cash proceeds of approximately $212 million to redeem 44,608 of our Series B preference units for their liquidation value of $50 million and to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed $2.1 million in cash to us in order to satisfy its one percent contribution requirement.

In March 2001, we completed a public offering of 2,250,000 common units. We used the net cash proceeds of $66.6 million from the offering to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed $0.7 million to us in order to satisfy its one percent capital contribution requirement.

Series B Preference Units

In August 2000, we issued 170,000 Series B preference units with a value of $170 million to acquire the Petal and Hattiesburg natural gas storage businesses. In October 2001, we redeemed 44,608 of the Series B preference units for $50 million liquidation value including accrued distributions of approximately $5.4 million, bringing the total number of units outstanding to 125,392. As of December 31, 2002, the liquidation value of the outstanding Series B preference units was approximately $158 million. In October 2003, we redeemed all 123,865 of our remaining outstanding Series B preference units for $156 million, a 7 percent discount from their liquidation value of $167 million. For this redemption, we used borrowings under our revolving credit facility. We reflected the discount as an increase to the common units capital, Series C units capital and to our general partner's capital accounts.

Series C Units

In November 2002, we issued to a subsidiary of El Paso Corporation 10,937,500 of Series C units at a price of $32 per unit, $350 million in the aggregate, as part of our consideration paid for the San Juan assets. The issuance of the Series C units was an exempt transaction under Section 4(2) of the Securities Act of 1993 as a transaction not involving a public offering. The Series C units are similar to our existing common units, except that the Series C units are non-voting. After April 30, 2003, the holder of the Series C units has the right to cause us to propose a vote of our common unitholders as to whether the Series C units should be converted into common units. If our common unitholders approve the conversion, then each Series C unit can convert into a common unit. If our common unitholders do not approve the conversion within 120 days after the vote is requested, then the distribution rate for the Series C units will increase to 105 percent of the common unit distribution rate in effect from time to time. Thereafter, the Series C unit distribution rate will increase on April 30, 2004, to 110 percent of the common unit distribution rate and on April 30, 2005, to 115 percent of the common unit distribution rate. In addition, our general partner contributed $3.5 million to us in order to satisfy its one percent capital contribution requirement. The holder of the Series C units has thus far not requested a vote to convert the Series C units into common units. As part of the proposed merger with Enterprise, Enterprise will purchase from a subsidiary of El Paso Corporation all of our outstanding Series C units. These units will not be converted to Enterprise common units in the merger but rather will remain limited partnership interests in GulfTerra after the closing of the merger transaction and, as such interest, will lose their GulfTerra common unit conversion and distribution rights.

Cash Distributions

We make quarterly distributions of 100 percent of our available cash, as defined in the partnership agreement, to our unitholders and to our general partner. Available cash generally consists of all cash receipts plus reductions in reserves less all cash disbursements and net additions to reserves. Our general partner has broad discretion to establish cash reserves for any proper partnership purpose. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt, or, as necessary, reserves to comply with the terms of our agreements or obligations.

Cash distributions on common units, Series C units and to our general partner are discretionary in nature and are not entitled to arrearages of minimum quarterly 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 year ended December 31, 2003:

MONTH PAID	COMMON UNIT	COMMON UNITHOLDERS	SERIES C UNITHOLDER	GENERAL PARTNER
	(PER UNIT)	(IN MILLIONS)		
February	$0.675	$29.7	$ 7.4	$15.0
May	$0.675	$32.0	$ 7.4	$15.9
August	$0.700	$34.8	$ 7.7	$18.0
November	$0.710	$41.4	$ 7.8	$21.2

In January 2004, we declared a cash distribution of $0.71 per common and Series C unit, $49.3 million in aggregate, for the quarter ended December 31, 2003, which we paid on February 14, 2004. In addition, we paid our general partner $21.3 million related to its general partner interest. At the current distribution rates, our general partner receives approximately 30.2 percent of our total cash distributions for its role as our general partner.

Option Plans

In August 1998, we adopted the 1998 Omnibus Compensation Plan (Omnibus Plan) to provide our general partner with the ability to issue unit options to attract and retain the services of knowledgeable officers and key management personnel. Unit options to purchase a maximum of 3 million common units may be issued pursuant to the Omnibus Plan. Unit options granted to date pursuant to the Omnibus Plan are not immediately exercisable. For unit options granted in 2001, one-half of the unit options are considered vested and exercisable one year after the date of grant and the remaining one-half of the unit options are considered vested and exercisable one year after the first anniversary of the date of grant. These unit options expire ten years from such grant date, but shall be subject to earlier termination under certain circumstances. No grants of unit options were made in 2002. During 2003, under our Omnibus Plan, we granted 17,500 unit options, 25,000 time-vested restricted units and will grant 25,000 restricted units, if certain performance targets are achieved, to employees of El Paso Field Services whose primary responsibilities are the commercial management of our assets.

In August 1998, we also adopted the 1998 Common Unit Plan for Non-Employee Directors (Director Plan), formerly the 1998 Unit Option Plan for Non-Employee Directors, to provide our general partner with the ability to issue unit options to attract and retain the services of knowledgeable directors. Unit options and restricted units to purchase a maximum of 100,000 of our common units may be issued pursuant to the Director Plan. Under the Director Plan, each non-employee director receives a grant of 2,500 unit options upon initial election to the Board of Directors and an annual unit option grant of 2,000 unit options and, beginning in 2001, an annual restricted unit grant equal to the director's annual retainer (including Chairman's retainers, if applicable) divided by the fair market value of the common units on the grant date upon each re-election to the Board of Directors. Each unit option that is granted will vest immediately at the date of grant and will expire ten years from such date, but will be subject to earlier termination in the event that such non-employee director ceases to be a director of our general partner for any reason, in which case the unit options expire 36 months after such date except in the case of death, in which case the unit options expire 12 months after such date. Each director receiving a grant of restricted units is recorded as a unitholder and has all the rights of a unitholder with respect to such units, including the right to distributions on those units. The restricted units are nontransferable during the director's service on the Board of Directors. The restrictions on the restricted units will end and the director will receive one common unit for each restricted unit granted upon the director's termination. The Director Plan is administered by a management committee consisting of the Chairman of the Board of Directors of the general partner and such other senior officers of our general partner or its affiliates as the Chairman may designate. During 2003, under the Director Plan, we granted 5,226 restricted units at a fair value per unit of $36.37 and 10,500 unit options with a grant price of $35.92. Restricted units awards representing 5,429 and 4,090 were granted during 2002 and 2001 with a fair value of $32.23 and $33.00 per unit. As of December 31, 2003, 12,292 restricted units were outstanding.

We have accounted for all of these unit options and restricted units, except for the unit options issued to non-employee directors, in accordance with SFAS No. 123. Under SFAS No. 123, we report the fair value of these issuances as deferred compensation. Deferred compensation is amortized to compensation expense over the respective vesting or performance period. We have accounted for the unit options issued to the non-employee directors of our general partner's Board of Directors in accordance with APB No. 25.

We issued time-vested restricted units and the performance-based restricted units at fair value at their date of grant. The restrictions on the time-vested units will lapse in four years from the date of grant. The restrictions on the performance-based restricted units will lapse if we achieve a specified level of target performance for identified "greenfield" projects by June 1, 2007 (for the 15,000 performance-based restricted units issued in June 2003) and by August 1, 2007 (for the 10,000 performance-based restricted units issued in August 2003). If we do not reach those targets by the applicable dates, the performance-based units will be forfeited. We will amortize the fair value of the time-vested restricted units over their four-year restricted period and the fair value of the performance-based restricted units over their performance periods. The performance-based restricted units are not entitled to vote or to receive distributions, until after (and if) we achieve specified level of target performance. The restricted units issued to non-employee directors of our general partner's Board of Directors were issued at fair value at their date of grant. This fair value is being amortized to compensation expense over the period of service, which we have estimated to be one year.

Total unamortized deferred compensation as of December 31, 2003 and 2002 was approximately $1.5 million and $1.2 million. Our 2001 deferred compensation is fully amortized. 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.

The following table summarizes activity under the Omnibus Plan and Director Plan (excluding our restricted units) as of and for the years ended December 31, 2003, 2002 and 2001.

	2003		2002		2001	
	# UNITS OF UNDERLYING OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE	# UNITS OF UNDERLYING OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE	# UNITS OF UNDERLYING OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at beginning of year	1,550,000	$32.17	1,614,500	$32.09	925,500	$27.15
Granted	28,000	35.08	8,000	32.23	1,016,500	35.00
Exercised	318,000	31.74	42,500	27.19	307,500	27.17
Forfeited	--	--	--	--	--	--
Canceled	144,000	34.99	30,000	34.99	20,000	27.19
Outstanding at end of year	1,116,000	$32.00	1,550,000	$32.17	1,614,500	$32.09
Options exercisable at end of year	1,106,000	$31.98	1,068,500	$30.88	606,500	$27.22

The fair value of each unit option granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions:

ASSUMPTION	2003	2002	2001
Expected term in years	7	8	8
Expected volatility	28.93%	31.05%	27.50%
Expected distributions	8.88%	8.09%	9.55%
Risk-free interest rate	3.31%	3.24%	5.05%

The Black-Scholes weighted average fair value of options granted during 2003, 2002, and 2001 was $3.55, $3.71, and $2.62 per unit option, respectively.

Options outstanding as of December 31, 2003, are summarized below:

OPTIONS OUTSTANDING	OPTIONS EXERCISABLE

RANGE OF EXERCISE PRICES	NUMBER OUTSTANDING	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE	WEIGHTED AVERAGE EXERCISE PRICE
$19.86 to $27.80	423,500	4.6	$27.13	423,500	$27.13
$27.80 to $39.72	692,500	6.9	$34.99	682,500	$34.99
$19.86 to $39.72	1,116,000	6.0	$32.00	1,106,000	$31.98

9. EARNINGS PER COMMON UNIT

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

	FOR THE YEARS ENDED DECEMBER 31,		
	2003	2002	2001
Numerator:			
Numerator for basic earnings per common unit --			
Income from continuing operations	$65,155	$34,275	$12,174
Income from discontinued operations	--	5,085	1,086
Cumulative effect of accounting change	1,340	--	--
	$66,495	$39,360	$13,260
Denominator:			
Denominator for basic earnings per common unit -- weighted-average common units	49,953	42,814	34,376
Effect of dilutive securities:			
Unit options	177	--	--
Restricted units	15	--	--
Series F convertible units	86	--	--
Denominator for diluted earnings per common unit -- adjusted for weighted-average common units	50,231	42,814	34,376
Basic earnings per common unit			
Income from continuing operations	$ 1.30	$ 0.80	$ 0.35
Income from discontinued operations	--	0.12	0.03
Cumulative effect of accounting change	0.03	--	--
	$ 1.33	$ 0.92	$ 0.38
Diluted earnings per common unit			
Income from continuing operations	$ 1.30	$ 0.80	$ 0.35
Income from discontinued operations	--	0.12	0.03
Cumulative effect of accounting change	0.02	--	--
	$ 1.32	$ 0.92	$ 0.38

10. RELATED PARTY TRANSACTIONS

The majority of our related party transactions are with affiliates of our general partner. Under an agreement that was in place before an indirect subsidiary of El Paso Corporation purchased our general partner, an affiliate of our general partner was obligated to provide individuals to perform the day to day financial, administrative, accounting and operational functions for us. As our activities increased, the fee for such services has also increased. Further, we provide services to various El Paso Corporation subsidiaries and, in turn, they provide us services. In addition, we have acquired a number of assets from subsidiaries of El Paso Corporation. We have not had any material transactions with Enterprise, other than the merger agreement transactions, since Enterprise acquired 50 percent of our general partner.

The following table provides summary data of our transactions with related parties for the years ended December 31:

	2003	2002	2001
	(IN THOUSANDS)		
Revenues received from related parties:			
Natural gas pipelines and plants	$ 84,375	$159,608	$20,710
Oil and NGL Logistics	29,413	26,288	25,249
Platform services(1)	--	--	35
Natural gas storage	--	3,016	2,325
Other(1)	--	9,809	5,676
	$113,788	$198,721	$53,995
Expenses paid to related parties:			
Purchased natural gas costs	$ 33,148	$ 22,784	$34,768
Operation and maintenance	91,208	60,458	33,721
	$124,356	$ 83,242	$68,489
Reimbursements received from related parties:			
Operation and maintenance	$ 2,426	$ 2,100	$11,499

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(1) In addition to revenues from continuing operations reflected above, we also received revenues from related parties in 2002 and 2001 of $6.8 million and $8.2 million for our Prince TLP and $1.0 million and $0.7 million for our 9 percent overriding royalty interest which are included in income from discontinued operations on our income statements.

For the years ended December 31, 2003, 2002 and 2001, revenues received from related parties consisted of approximately 13%, 43% and 28% of our revenue from continuing operations. Also, we have undertaken efforts to reduce our transactions with El Paso Merchant Energy North America Company (Merchant Energy) and as of June 30, 2003, we replaced all our month-to-month arrangements that were previously with Merchant Energy with similar arrangements with third parties.

The following table provides summary data categorized by our related parties for the years ended December 31:

	2003	2002	2001
	(IN THOUSANDS)		
Revenues received from related parties:			
El Paso Corporation			
El Paso Merchant Energy North America Company	$ 30,146	$ 92,675	$16,433
El Paso Production Company(1)	9,109	9,054	4,230
Southern Natural Gas Company	13	112	277
Tennessee Gas Pipeline Company	93	--	638
El Paso Field Services	74,427	96,880	32,382
Unconsolidated Subsidiaries			
Manta Ray Offshore(2)	--	--	35
	$113,788	$198,721	$53,995
Purchased natural gas costs paid to related parties:			
El Paso Corporation			
El Paso Merchant Energy North America Company	$ 27,777	$ 19,226	$28,169
El Paso Production Company	--	2,251	6,412
Southern Natural Gas Company	143	245	187
Tennessee Gas Pipeline Company	--	70	--
El Paso Field Services	5,181	950	--
El Paso Natural Gas Company	47	42	--
	$ 33,148	$ 22,784	$34,768
Operating expenses paid to related parties:			
El Paso Corporation			
El Paso Field Services	$ 90,925	$ 60,000	$33,187
Unconsolidated Subsidiaries			
Poseidon Oil Pipeline Company	283	458	534
	$ 91,208	$ 60,458	$33,721
Reimbursements received from related parties:			
Unconsolidated Subsidiaries			
Deepwater Holdings(3)	$ --	$ --	$ 9,399
Poseidon Oil Pipeline Company	2,426	2,100	2,100
	$ 2,426	$ 2,100	$11,499

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(1) In addition to revenues from continuing operations from El Paso Production Company reflected above, during 2002 and 2001 we also received revenues of $7.8 million and $8.9 million from El Paso Production Company which are included in income from discontinued operations in our income statements.

(2) We sold our interest in Manta Ray Offshore in January 2001 in connection with El Paso Corporation's merger with the Coastal Corporation.

(3) In January 2001, Deepwater Holdings sold its Stingray and West Cameron subsidiaries. In April 2001, Deepwater Holdings sold its UTOS subsidiary. In October 2001, we acquired the remaining 50 percent of Deepwater Holdings, and as a result of this transaction, on a going forward basis, Deepwater Holdings is consolidated in our financial statements and our agreement with Deepwater Holdings terminated.

Revenues received from related parties

EPN Holding Assets. Our revenues from related parties increased in 2002 as a result of our EPN Holding transaction in which we acquired gathering, transportation and processing contracts with affiliates of our general partner. For the years ended December 31, 2003 and 2002, we received $26.5 million and

$68.9 million from El Paso Merchant Energy North America Company, $19.9 million and $35.8 million from El Paso Field Services and $3.4 million and $4.0 million from El Paso Production Company.

GTM Texas. In connection with our acquisition of GTM Texas in February 2001, we entered into a 20-year fee-based transportation and fractionation agreement with El Paso Field Services. Pursuant to this agreement, we receive a fixed fee for each barrel of NGL transported and fractionated by our facilities. Approximately 25 percent of our per barrel fee is escalated annually for increases in inflation. For the years ended December 31, 2003, 2002 and 2001, we received revenue of approximately $21.5 million, $26.0 million and $25.2 million related to this agreement.

Chaco processing plant. In connection with our Chaco transaction in October 2001, we entered into a 20-year fee-based processing agreement with El Paso Field Services. Pursuant to this agreement, we receive a fixed fee for each dekatherm of natural gas that we process at the Chaco plant. For the years ended December 31, 2002 and 2001, we received revenue of $29.6 million and $6.5 million related to this agreement. In accordance with the original construction financing agreements, the Chaco plant is under an operating lease to El Paso Field Services. For the years ended December 31, 2002 and 2001, we received $1.8 million and $0.6 million related to this lease. As a result of the San Juan asset acquisition in November 2002, the processing agreement and the operating lease were terminated.

Storage facilities. With the April 2002 acquisition of the EPN Holding assets, we purchased contracts held by Wilson Storage with El Paso Merchant Energy North America Company. For the year ended December 31, 2002, we received approximately $2.9 million from El Paso Merchant Energy North America Company for natural gas storage fees. El Paso Merchant Energy North America Company and Tennessee Gas Pipeline Company use our Petal and Hattiesburg storage facilities from time to time. For the years ended December 31, 2002 and 2001 we received approximately $0.1 million and $1.6 million from El Paso Merchant Energy North America Company for natural gas storage fees. For the year ended December 31, 2001 we received approximately $0.7 million from Tennessee Gas Pipeline Company.

Prince TLP. In September 2001, we placed our Prince TLP in service. Prior to April 1, 2002, we received a monthly demand charge of approximately $1.9 million as well as processing fees from El Paso Production Company related to production on the Prince TLP. For the year ended December 31, 2002 and the four months ended December 31, 2001, we received $6.8 million and $8.2 million in platform revenue related to this agreement. In connection with our acquisition of the EPN Holding assets from El Paso Corporation, in April 2002 we sold our Prince TLP to subsidiaries of El Paso Corporation and these revenues are reflected in our income from discontinued operations.

Production fields. Through 2000 we had agreed to sell substantially all of our oil and natural gas production to El Paso Merchant Energy North America Company on a month to month basis. The agreement provided fees equal to two percent of the sales value of crude oil and condensate and $0.015 per dekatherm of natural gas for marketing production. Beginning in the fourth quarter of 2000, we began selling our oil and natural gas directly to third parties and our oil and natural gas sales related to El Paso Merchant Energy North America Company were approximately $9.8 million and $5.7 million for years ended December 31, 2002 and 2001.

In October 1999, we farmed out our working interest in the Prince Field to El Paso Production Company. Under the terms of the farmout agreement, our net overriding royalty interest in the Prince Field increased to a weighted average of approximately nine percent. El Paso Production Company began production on the Prince Field in September 2001. For the year ended December 31, 2002 and the four months ended December 31, 2001, we recorded approximately $1.0 million and $0.7 million in revenues related to our overriding royalty interest in the Prince Field. In connection with our acquisition of the EPN Holding assets from El Paso Corporation, in April 2002 we sold our 9 percent overriding royalty interest in the Prince Field to subsidiaries of El Paso Corporation and these revenues are reflected in our income from discontinued operations.

GulfTerra Alabama Intrastate. Several El Paso Corporation subsidiaries buy and transport natural gas on our GulfTerra Alabama Intrastate system. For the years ended December 31, 2003, 2002 and 2001, we received approximately $0.7 million, $6.8 million and $8.3 million from El Paso Merchant Energy North America Company. For the years ended December 31, 2003, 2002 and 2001, we received approximately $4.5 million, $4.5 million and $4.2 million from El Paso Production Company. For the years ended December 31, 2003, 2002 and 2001, we received approximately $0.1 million, $0.1 million and $0.2 million from Southern Natural Gas Company.

HIOS. In October 2001, HIOS became a wholly-owned asset through our acquisition of the remaining 50 percent equity interest in Deepwater Holdings. HIOS is a natural gas transmission system that has entered into interruptible transportation agreements at a non-discounted rate of $0.1244. For the years ended December 31, 2003 and 2002 and approximately three months ended December 31, 2001, we received $0.1 million, $1.4 million and $0.8 million from El Paso Merchant Energy. For the year ended December 31, 2003 and 2002, we received $1.2 million and $0.6 million from El Paso Production Company.

Texas NGL assets. In connection with our acquisition of the San Juan assets in November, 2002, we entered into a 10-year transportation agreement with El Paso Field Services. Pursuant to this agreement, beginning January 1, 2003, we receive a fee of $1.5 million per year for transportation on our NGL pipeline which extends from Corpus Christi to near Houston. In addition, we provide transportation, fractionation, storage and terminaling services to El Paso Field Services, as well as to various third parties, typically under agreements of one year term or less. We received approximately $7.5 million and $0.3 million in revenues from El Paso Field Services for the years ended December 31, 2003 and 2002.

Other. In addition to the revenues discussed above, we received $2.8 million and $2.6 million from El Paso Merchant North America and $25.6 million and $3.3 million from El Paso Field Services during 2003 and 2002 for additional gathering and processing services. The 2003 increase in revenues for El Paso Field Services was primarily as a result of higher natural gas prices and NGL volumes sold to El Paso Field Services from our Big Thicket assets.

Unconsolidated Subsidiaries. For the years ended December 31, 2001 we received approximately $0.03 million from Manta Ray Offshore Gathering as platform access and processing fees related to our South Timbalier 292 platform and our Ship Shoal 332 platform. We sold our interest in Manta Ray Offshore in January 2001 in connection with El Paso's merger with the Coastal Corporation.

Expenses paid to related parties

Cost of natural gas. Our cost of natural gas paid to related parties increased in 2003 and 2002 as a result of our San Juan assets acquisitions and our EPN Holding transaction in which we acquired contracts with affiliates of our general partner. For the year ended December 31, 2003, our San Juan assets had cost of natural gas expenses of $1.3 million from El Paso Merchant Energy North America and $0.3 million from El Paso Field Services. For the year ended December 31, 2003 and 2002, our EPN Holding assets had cost of natural gas expenses of $0.9 million and $0.3 million from El Paso Merchant Energy North America Company and $3.5 million and $0.4 million from El Paso Field Services relating to the GulfTerra Texas gathering system. GulfTerra Alabama Intrastate's purchases of natural gas include transactions with affiliates of our general partner. For the years ended December 31, 2003, 2002 and 2001, we had natural gas purchases of approximately $25.6 million, $18.9 million and $28.2 million from El Paso Merchant Energy North America Company, and $0.1 million, $0.2 million and $0.2 million from Southern Natural Gas Company and $2.3 million and $6.4 million from El Paso Production Company for the years ended December 31, 2002 and 2001. We also receive lease and throughput fees from El Paso Field Services for Hattiesburg and Anse

La Butte. For the year ended December 31, 2002 we received $0.5 million from El Paso Field Services related to these fees.

Operating Expenses. Substantially all of the individuals who perform the day-to-day financial, administrative, accounting and operational functions for us, as well as those who are responsible for directing and controlling us, are currently employed by El Paso Corporation. Under a general and administrative services agreement between subsidiaries of El Paso Corporation and us, a fee of approximately $0.8 million per month was charged to our general partner, and accordingly, to us, which is intended to approximate the amount of resources allocated by El Paso Corporation and its affiliates in providing various operational, financial, accounting and administrative services on behalf of our general partner and us. In April 2002, in connection with our acquisition of EPN Holding assets, our general and administrative services agreement was extended to December 31, 2005, and the fee increased to approximately $1.6 million per month. In November 2002, as a result of the San Juan assets acquisition, the monthly fee under our general and administrative services agreement increased by $1.3 million, bringing our total monthly fee to $2.9 million. We believe this fee approximates the actual costs incurred. Under the terms of the partnership agreement, our general partner is entitled to reimbursement of all reasonable general and administrative expenses and other reasonable expenses incurred by our general partner and its affiliates for, or on our behalf, including, but not limited to, amounts payable by our general partner to El Paso Corporation under its management agreement. We are also charged for insurance and other costs paid directly by El Paso Field Services on our behalf.

As we became operator of additional facilities or systems, acquired new operations or constructed new facilities, we entered into additional management and operating agreements with El Paso Field Services. All fees paid under these contracts approximate actual costs incurred.

The following table shows the amount El Paso Field Services charged us for each of our agreements for the year ended December 31:

	2003	2002	2001
	(IN THOUSANDS)		
Basic management fee	$34,800	$18,092	$ 9,300
Operating fees(1)	52,924	38,422	19,821
Insurance and other costs	3,201	3,486	4,066
	$90,925	$60,000	$33,187

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(1) Operating fees increased from 2002 to 2003 and from 2001 to 2002 due to the acquisition of the San Juan assets and EPN Holding assets.

Cost Reimbursements. In connection with becoming the operator of Poseidon, we entered into an operating agreement in January 2001. All fees received under contracts approximate actual costs incurred.

Acquisitions

We have purchased assets from related parties. See Note 2 for a discussion of these asset acquisitions.

Other Matters

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 resolutions of these matters result in judgments against us. For a further discussion of these matters see Note 11, Commitments and

Contingencies, Legal Proceedings. Some of our agreements obligate certain indirect subsidiaries of El Paso Corporation to pay for capital costs related to maintaining assets which were acquired by us, if such costs exceed negotiated thresholds. We have made claims for approximately $5 million for costs incurred during the year ended December 31, 2003 as costs exceeded the established thresholds for the year ended December 31, 2003.

We have also entered into capital contribution arrangements with entities owned by El Paso Corporation, including its regulated pipelines, in the past, and will most likely do so in the future, as part of our normal commercial activities in the Gulf of Mexico. We have an agreement to receive $6.1 million, of which $3.0 million has been collected, from ANR Pipeline Company for our Phoenix project. As of December 31, 2003, we have received $10.5 million from ANR Pipeline and $7.0 million from El Paso Field Services for the Marco Polo natural gas pipeline. In October 2003, we collected $2 million from Tennessee Gas Pipeline for our Medusa project. These amounts 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. El Paso Field Services' contribution is in anticipation of additional natural gas volumes that will flow through to its onshore natural gas processing facilities.

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 El Paso Natural Gas Company (EPNG), a subsidiary of El Paso Corporation. Copper Eagle Gas Storage is developing a natural gas storage project located outside of Phoenix, Arizona. Arizona Gas Storage 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. 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 over the next twelve months, from EPNG and we recorded a gain of $882 thousand related to the sale of Copper Eagle. In the event of EPNG default, the Copper Eagle Gas Storage project will revert back to the original owners without compensation to EPNG.

In September 2003, we 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 a 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. If Southern Natural Gas determines that there is sufficient market interest, it would purchase the land and mineral rights related to the proposed storage cavern and would pay our costs to construct the storage cavern and related facilities. Upon completion of the storage cavern, Southern Natural Gas would acquire an undivided interest in our Petal pipeline connected to the storage cavern. We would also enter into an arrangement with Southern Natural Gas under which we would operate the storage cavern and pipeline on its behalf.

Before we consummate this transaction, and enter into definitive transaction documents, the transaction must be recommended by the audit and conflicts committee of our general partner's board of directors, which committee consists solely of directors meeting the independent director requirements established by the NYSE and the Sarbanes-Oxley Act, and then approved by our general partner's full board of directors.

In October 2003, we exchanged with El Paso Corporation its obligation to repurchase the Chaco plant from us in 19 years for additional assets (refer to Note 2). Also in October 2003, we redeemed all of our outstanding Series B preference units (refer to Note 8).

The counterparty for one of our San Juan hedging activities is J. Aron and Company, an affiliate of Goldman Sachs. Goldman Sachs was also a co-manager of our 4,800,000 public common unit offering in October 2003, and is one of the lenders under our revolving credit facility and owned 9.9 percent of our general partner during part of the fourth quarter of 2003.

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

	DECEMBER 31, 2003	DECEMBER 31, 2002
	(IN THOUSANDS)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 4,113	$30,512
El Paso Production Company	5,991	4,346
Tennessee Gas Pipeline Company	1,350	930
El Paso Field Services(1)	16,571	36,071
El Paso Natural Gas Company	4,255	1,033
ANR Pipeline Company	1,600	671
Other	830	627
	34,710	74,190
Unconsolidated Subsidiaries		
Deepwater Gateway	3,939	9,636
Cameron Highway	9,302	--
Other	14	--
	13,255	9,636
Total	$47,965	$83,826

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(1) The December 2002 receivable balance includes approximately $15 million of natural gas imbalances relating to our EPN Holding acquisition.

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

	DECEMBER 31, 2003	DECEMBER 31, 2002
	(IN THOUSANDS)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 7,523	$ 8,871
El Paso Production Company	4,069	14,518
Tennessee Gas Pipeline Company	1,278	1,319
El Paso Field Services(1)	13,869	55,648
El Paso Natural Gas Company	942	1,475
El Paso Corporation	6,249	4,181
Southern Natural Gas	1,871	--
Other	667	132
	36,468	86,144
Unconsolidated Subsidiaries		
Deepwater Gateway	2,268	--
Other	134	--
	2,402	--
Total	$38,870	$86,144

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(1) The December 2002 payable balance includes approximately $19 million of working capital adjustments relating to our EPN Holding acquisition due to El Paso Field Services; and approximately $22 million of natural gas imbalances relating to our EPN Holding acquisition.

In connection with the sale of our Gulf of Mexico assets in January 2001, El Paso Corporation agreed to make quarterly payments to us of $2.25 million for three years beginning March 2001 and ending with a $2 million payment in the first quarter of 2004. The present value of the amounts due from El Paso Corporation were classified as follows:

	DECEMBER 31, 2003	DECEMBER 31, 2002
	(IN THOUSANDS)	
Accounts receivable, net....................................	$1,960	$ 8,403
Other noncurrent assets....................................	--	1,960
	$1,960	$10,363

11. 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, and 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 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., City of Edinburg, Houston Pipe Line Company LP, and City of Corpus Christi discussed below.

During 2000, Leapartners, L.P. filed a suit against El Paso Field Services and others in the District Court of Loving County, Texas, alleging a breach of contract to gather and process natural gas in areas of western Texas related to an asset now owned by GulfTerra Holding. In May 2001, the court ruled in favor of

Leapartners and entered a judgment against El Paso Field Services of approximately $10 million. El Paso Field Services filed an appeal with the Eighth Court of Appeals in El Paso, Texas. On August 15, 2003 the Court of Appeals reversed the lower's courts calculation of past judgment interest but otherwise affirmed the judgment. A motion for a rehearing was denied. A petition for review by the Texas Supreme Court has been filed.

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

In December 2000, a 30-inch natural gas pipeline jointly owned by GulfTerra Intrastate, L.P. (GulfTerra Intrastate) now owned by GulfTerra Holding, and Houston Pipe Line Company LP ruptured in Mont Belvieu, Texas, near Baytown, resulting in substantial property damage and minor physical injury. GulfTerra Intrastate is the operator of the pipeline. Two lawsuits were filed in the state district court in Chambers County, Texas by eight plaintiffs, including two homeowners' insurers. The suits sought recovery for physical pain and suffering, mental anguish, physical impairment, medical expenses, and property damage. Houston Pipe Line Company was added as an additional defendant. In accordance with the terms of the operating agreement, GulfTerra Intrastate agreed to assume the defense of and to indemnify Houston Pipe Line Company. As of December 31, 2003, all claims have now been settled and these settlements had no impact on our financial statements.

The City of Corpus Christi, Texas (the "City") alleged that GulfTerra Texas and various Coastal entities owed it monies for past obligations under City ordinances that propose to tax GulfTerra Texas on its gross receipts from local natural gas sales for the use of street rights-of-way. Some but not all of the GulfTerra Texas pipe at issue has been using the rights-of-way since the 1960's. In addition, the City demanded that GulfTerra Texas agree to a going-forward consent agreement in order for the GulfTerra Texas pipe and Coastal pipe to have the right to remain in the City rights-of-way. In December 2003, GulfTerra Texas and the City entered into a license agreement releasing GulfTerra Texas from any past obligations and providing certain rights for the use of the City rights-of-way and City owned property. This agreement was retroactive to October 1, 2002.

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. 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 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 GulfTerra and BP, GulfTerra requested that BP indemnify GulfTerra 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. 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.

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 December 31, 2003, we had no reserves for our legal matters.

While the outcome of our outstanding legal matters cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, results of operations or cash flows. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Environmental

Each of our operating segments is subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations are applicable to each segment and require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2003, we had a reserve of approximately $21 million, included in other noncurrent liabilities, for remediation costs expected to be incurred over time associated with mercury meters. We assumed this liability in connection with our April 2002 acquisition of the EPN Holding assets. As part of the November 2002 San Juan assets acquisition, El Paso Corporation has agreed to indemnify us for all the known and unknown environmental liabilities related to the assets we purchased up to the purchase price of $766 million. We will only be indemnified for unknown liabilities for up to three years from the purchase date of this acquisition. In addition, we have been indemnified by third parties for remediation costs associated with other assets we have purchased. We expect to make capital expenditures for environmental matters of approximately $3 million in the aggregate for the years 2004 through 2008, primarily to comply with clean air regulations.

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

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 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 HIOS natural gas pipeline and Petal natural gas storage facility, including the 60-mile Petal natural gas pipeline, are interstate facilities as defined by the Natural Gas Act, the regulations dictate how HIOS and Petal conduct business and interact with all energy affiliates of El Paso Corporation and us.

The standards of conduct require us, absent a waiver, to functionally separate our HIOS and Petal interstate facilities from our other entities. We must dedicate employees to manage and operate our interstate facilities independently from our other Energy Affiliates. This employee group must function independently and is prohibited from communicating non-public transportation information or customer information to its Energy Affiliates. Separate office facilities and systems are necessary because of the requirement to restrict affiliate access to interstate transportation information. The Final Rule also limits the sharing of employees and offices with Energy Affiliates. The Final Rule was effective on February 9, 2004, subject to possible rehearing. On that date, each transmission provider filed with FERC and posted on the internet website a plan and scheduling for implementing this Final Rule. By June 1, 2004, written procedures implementing this Final Rule will be posted on the internet website. Requests for rehearing have been filed and are pending. At this time, we cannot predict the outcome of these requests, but at a minimum, adoption of the regulations in the form outlined in the Final Rule will place additional administrative and operational burdens on us.

Pipeline Safety Final Rule. In December 2003, the U.S. Department of Transportation issued a Final Rule requiring pipeline operators to develop integrity management programs for gas transmission pipelines located where a leak or rupture could do the most harm in "high consequence areas," or HCA. The final rule requires operators to (1) perform ongoing assessments of pipeline integrity; (2) identify and characterize applicable threats to pipeline segments that could impact an HCA; (3) improve data collection, integration and analysis; (4) repair and remediate the pipeline as necessary; and (5) implement preventive and mitigative actions. The final rule incorporates the requirements of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. The Final Rule is effective as of January 14, 2004. At this time, we cannot predict the outcome of this final rule.

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 has conducted a hearing on this matter and an initial decision is expected to be issued in April 2004.

During the latter half of 2002, we experienced a significant unfavorable variance between the fuel usage on HIOS and the fuel collected from our customers for our use. We believe a series of events may have contributed to this variance, including two major storms that hit the Gulf Coast Region (and these assets) in late September and early October of 2002. As of December 31, 2003, we had recorded fuel differences of approximately $8.2 million, which is included in other non-current assets. We are currently in discussions with the FERC as well as our customers regarding the potential collection of some or all of the fuel differences. At this time we are not able to determine what amount, if any, may be collectible from our customers. Any amount we are unable to resolve or collect from our customers will negatively impact our earnings.

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. 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 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 on February 25, 2004. Meanwhile in December 2002, GulfTerra Texas amended its Statement of Operating Conditions to provide shippers the option of resolving daily imbalances using a third-party imbalance service provider.

Falcon filed a formal complaint in March 2003 at the Railroad Commission of Texas claiming that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering hourly imbalance management services on the GulfTerra Texas system. GulfTerra Texas filed a response specifically denying Falcon's assertions and requesting that the complaint be denied. The Railroad Commission has set their case for hearing beginning on April 13, 2004. The City Board of Public Service of San Antonio filed an intervention in opposition to Falcon's complaint.

While the outcome of all of our rates and regulatory matters cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, results of operations or cash flows. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Joint Ventures

We conduct a portion of our business through joint venture arrangements (including our Cameron Highway, Deepwater Gateway and Poseidon joint ventures) we form to construct, operate and finance the development of our onshore and offshore midstream energy businesses. We are obligated to make our proportionate share of additional capital contributions to our joint ventures only to the extent that they are unable to satisfy their obligations from other sources including proceeds from credit arrangements.

Operating Lease

We have long-term operating lease commitments associated with the Wilson natural gas storage facility we acquired in April 2002 in connection with the EPN Holding acquisition. The term of the natural gas storage facility and base gas leases runs through January 2008, and subject to certain conditions, has one or more optional renewal periods of five years each at fair market rent at the time of renewal. We also have long-term operating lease commitments associated with two NGL storage facilities in Texas we acquired in November 2002 in connection with our San Juan asset acquisition. The leases covering these facilities expire in 2006 and 2012.

The future minimum lease payments under these operating lease commitments as of December 31, 2003 are as follows (in millions):

2004	$ 7
2005	7
2006	7
2007	6
2008	3
Thereafter	2
Total minimum lease payments	$32

Rental expense under operating leases was approximately $7.2 million and $3.9 million for the years ended December 31, 2003 and 2002. We did not have any operating leases prior to our acquisition of the EPN Holding assets in April 2002.

Other Matters

As a result of current circumstances generally surrounding the energy sector, the creditworthiness of several industry participants has been called into question. As a result of these general circumstances, we have established an internal group to monitor our exposure to and determine, as appropriate, whether we should request prepayments, letters of credit or other collateral from our counterparties.

12. 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. On January 1, 2001, we adopted the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. We did not have any derivative contracts in place at December 31, 2000, and therefore, there was no transition adjustment recorded in our financial statements. During 2003, 2002 and 2001, we entered into cash flow hedges.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices relating to gathering activities in the San Juan Basin in anticipation of our acquisition of the San Juan assets. The derivative is a financial swap on 30,000 MMBtu per day whereby we receive a fixed price of $3.525 per MMBtu and pay a floating price based on the San Juan index. From August 2002 through our acquisition date, November 27, 2002, we accounted for this derivative through current earnings since it did not qualify for hedge accounting under SFAS No. 133. Through the acquisition date in 2002, we recognized a $0.4 million gain in the margin of our natural gas pipelines and plants segment. Beginning with the acquisition date in November 2002, we are accounting for this derivative as a cash flow hedge under SFAS No. 133. In February and August 2003, we entered into additional 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 December 31, 2003 and 2002, the fair value of these cash flow hedges was a liability of $5.8 million and $4.8 million, as the market price at those dates was higher than the hedge price. For the year ended December 31, 2003, we reclassified approximately $9.8 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income as a decrease in revenue. No ineffectiveness exists in our hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction. In connection with our San Juan asset purchase, we also acquired the outstanding risk management positions at the Chaco plant. The value of these NGL and natural gas positions was a $0.5 million liability at the acquisition date and this amount was included in the working capital adjustments to the purchase price. These positions expired in December 2002.

In connection with our GulfTerra Alabama Intrastate operations, we have fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We entered into cash flow hedges in 2002 and 2003 to offset the risk of increasing natural gas prices. As of December 31, 2003, the fair value of these cash flow hedges was an asset of approximately $77 thousand. For the twelve months ended December 31, 2003, we reclassified approximately $218 thousand of unrealized accumulated gain related to these derivatives from accumulated other comprehensive income to earnings. As of December 31, 2002, the fair value of these cash flow hedges was an asset of $86 thousand. During the year ended December 31, 2002, we reclassified a loss of $1.4 million from other comprehensive income to earnings. No ineffectiveness exists in our hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

Beginning in April 2002, in connection with our EPN Holding acquisition, we had swaps in place for our interest in the Indian Basin processing plant to hedge the price received for the sale of natural gas liquids. All of these hedges expired by December 31, 2002, and we recorded a loss of $163 thousand during 2002 for these cash flow hedges. We did not have any ineffectiveness in our hedging relationship since all sale prices were based on the same index as the hedge transaction.

During 2003, we entered into additional derivative financial instruments to hedge a portion of our business' exposure to changes in NGL prices during 2003 and 2004. We entered into financial swaps for 3,500 barrels per day for February through June 2003, 3,200 barrels per day for July 2003, 4,900 barrels per day for August 2003, and 6,000 barrels per day for August 2003 through September 2004. The average fixed price received was $0.49 per gallon for 2003 and will be $0.47 per gallon for 2004 while we pay a monthly average floating price based on the OPIS average price for each month. As of December 31, 2003, the fair value of these cash flow hedges was a liability of $3.3 million. For the twelve months ended December 31, 2003, we reclassified approximately $0.4 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income to earnings.

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 its $185 million variable rate revolving credit facility at 3.49% over the life of the swap. Prior to April 2003, under its credit facility, Poseidon paid an additional 1.50% over the LIBOR rate resulting in an effective interest rate of 4.99% on the hedged notional amount. Beginning in April 2003, the additional interest Poseidon pays over LIBOR was reduced resulting in an effective fixed interest rate of 4.74% on the hedged notional amount. This interest rate swap expired on January 9, 2004. We have recognized as a reduction in income our 36 percent share of Poseidon's realized loss on the interest rate swap of $1.7 million for the twelve months ended December 31, 2003, or $0.6 million, through our earnings from unconsolidated affiliates. As of December 31, 2002, the fair value of its interest rate swap was a liability of $1.4 million, as the market interest rate was lower than the hedge rate, resulting in accumulated other comprehensive loss of $1.4 million. We included our 36 percent share of this liability of $0.5 million as a reduction of our investment in Poseidon and as loss in accumulated other comprehensive income. Additionally, we recognized in income our 36 percent share of Poseidon's realized loss of $1.2 million for the twelve months ended December 31, 2002, or $0.4 million, through our earnings from unconsolidated affiliates.

We estimate the entire $9.0 million of unrealized losses included in accumulated other comprehensive income at December 31, 2003, will be reclassified from accumulated other comprehensive income as a reduction to earnings over the next 12 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 at the "hedged price" under the derivative financial instruments.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million out of $480 million of our 8 1/2% senior subordinated notes due 2011. With this swap agreement, we pay the counterparty a LIBOR based interest rate plus a spread of 4.20% (which rate was 1.55% at December 31, 2003) and receive a fixed rate of 8 1/2%. We are accounting for this derivative as a fair value hedge under SFAS No. 133. As of December 31, 2003, the fair value of the interest rate swap was a liability included in non-current liabilities of approximately $7.4 million and the fair value of the hedged debt decreased by the same amount.

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. Through June 2003, the counterparty for our GulfTerra Alabama Intrastate operations was El Paso Merchant Energy. Beginning in August 2003, the counterparty is UBS Warburg, and we do not require collateral or anticipate non-performance by this counterparty. The counterparty for our NGL hedging activities for the Indian Basin and Chaco plants is J. Aron and Company, an affiliate of Goldman Sachs. We do not require collateral and do not anticipate non-performance by this counterparty. The counterparty for Poseidon's hedging activity is Credit Lyonnais. Poseidon does not require collateral and does not anticipate non-performance by this counterparty. Wachovia Bank is our counterparty on our interest rate swap on the 8 1/2% notes, and we do not require collateral or anticipate non-performance by this counterparty.

13. SUPPLEMENTAL DISCLOSURES TO THE STATEMENTS OF CASH FLOWS

Cash paid for interest, net of amounts capitalized were as follows:

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS)		
Interest	$135,131	$73,598	$41,020

Noncash investing and financing activities excluded from the consolidated statements of cash flows were as follows:

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS)		
Investment in Cameron Highway Oil Pipeline Company Joint Venture	$50,836	$ --	$ --
Exchange with El Paso Corporation	23,275	--	--
Adoption of SFAS No. 143	5,726	--	--
Note receivable due to sale of Copper Eagle	3,656		
Increase in property, plant and equipment, offset by accounts payable and other noncurrent liabilities due to purchase price adjustments	377		
Acquisition of San Juan assets			
Issuance of Series C units	--	350,000	--
Investment in processing agreement classified to property, plant and equipment	--	114,412	--
Acquisition of EPN Holding assets			
Issuance of common units	--	6,000	--
Acquisition of additional 50 percent interest in Deepwater Holdings			
Working capital acquired	--	--	7,494

14. MAJOR CUSTOMERS

The percentage of our revenue from major customers was as follows:

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Chevron	14%	--	--
BHP Petroleum	14%	--	--
Burlington Resources	13%	--	--
El Paso Merchant Energy North America Company	--	21%	--
El Paso Field Services	--	18%	16%
Alabama Gas Corporation	--	--	14%

The 2003 major customers are a result of our San Juan asset acquisition in November 2002. Also, during 2003 we decreased our activities with affiliates of El Paso Corporation, including replacing all our month-to-month arrangements that were previously with El Paso Merchant Energy with similar arrangements with third parties. The 2002 percentage increase in revenue from El Paso Merchant Energy North America Company and El Paso Field Services is primarily due to our EPN Holding acquisition completed in 2002.

15. 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 and 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.

The accounting policies of the individual segments are the same as those described in Note 1. We record intersegment revenues at rates that approximate market.

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, income taxes, depreciation and amortization and other adjustments. Historically our lenders and equity investors have viewed our performance cash flows measure as an indication of our ability to generate sufficient cash to meet debt obligations or to pay distributions, we believe that there has been a shift in investors' evaluation regarding investments in MLPs and they now put as much focus on the performance of an MLP investment as they do its ability to pay distributions. For that reason, we disclose performance cash flows as a measure of our segment's performance. We believe performance cash flows is also useful to our investors because it allows them to evaluate the effectiveness of our business segments from an operational perspective, exclusive of the costs to finance those activities, income taxes and depreciation and amortization, none 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.

Our operating results and financial position reflect the acquisitions of the San Juan assets in November 2002, the EPN Holding assets in April 2002, the Chaco plant and the remaining 50 percent interest we did not already own in Deepwater Holdings in October 2001 and GTM Texas in February 2001. The acquisitions were accounted for as purchases and therefore operating results of these acquired entities are included prospectively from the purchase date. The following are results as of and for the periods ended December 31:

SEGMENT	NATURAL GAS PIPELINES & PLANTS	OIL AND NGL LOGISTICS	NATURAL GAS STORAGE	PLATFORM SERVICES	NON-SEGMENT ACTIVITY(1)	TOTAL
	(IN THOUSANDS)					
FOR THE YEAR ENDED DECEMBER 31, 2003						
Revenue from external customers....................	$ 734,670	$ 53,850	$ 44,297	$ 20,861	$ 17,811	$ 871,489
Intersegment revenue...........	127	--	278	2,603	(3,008)	--
Depreciation, depletion and amortization.................	68,747	8,603	11,720	5,334	4,442	98,846
Earnings from unconsolidated investments..................	2,377	8,098	898	--	--	11,373
Performance cash flows..........	311,164	59,053	29,554	20,181	N/A	N/A
Assets.........................	2,289,546	464,246	315,853	162,275	89,660	3,321,580
FOR THE YEAR ENDED DECEMBER 31, 2002						
Revenue from external customers(2).................	$ 357,581	$ 37,645	$ 28,602	$ 16,672	$ 16,890	$ 457,390
Intersegment revenue...........	227	--	--	9,283	(9,510)	--
Depreciation, depletion and amortization.................	44,479	6,481	8,503	4,205	8,458	72,126
Earnings from unconsolidated investments..................	194	13,445	--	--	--	13,639
Performance cash flows..........	167,185	43,347	16,629	29,224	N/A	N/A
Assets.........................	2,279,955	265,900	320,662	140,758	123,621	3,130,896
FOR THE YEAR ENDED DECEMBER 31, 2001						
Revenue from external customers....................	$ 100,683	$ 32,327	$ 19,373	$ 15,385	$ 25,638	$ 193,406
Intersegment revenue...........	381	--	--	12,620	(13,001)	--
Depreciation, depletion and amortization.................	12,378	5,113	5,605	4,154	7,528	34,778
Asset impairment charge.........	3,921	--	--	--	--	3,921
Earnings (loss) from unconsolidated investments....	(9,761)	18,210	--	--	--	8,449
Performance cash flows..........	52,200	47,560				

13,209 30,783 N/A N/A
Assets..........................
563,698 195,839 226,991 115,364
69,968 1,171,860

- ---------------

(1) Represents predominately 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) The revenue amount for our Oil and NGL Logistics segment has been reduced by $10.5 million to reflect the reclassification of Typhoon Oil Pipeline's cost of sales and other products. See Note 1, Summary of Significant Accounting Policies, for a further discussion.

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

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
Natural gas pipelines & plants	$311,164	$167,185	$ 52,200
Oil & NGL logistics	59,053	43,347	47,560
Natural gas storage	29,554	16,629	13,209
Platform services	20,181	29,224	30,783
Segment performance cash flows	419,952	256,385	143,752
Plus: Other, nonsegment results	15,107	10,427	17,688
Earnings from unconsolidated affiliates	11,373	13,639	8,449
Income from discontinued operations	--	5,136	1,097
Cumulative effect of accounting change	1,690	--	--
Noncash hedge gain	--	411	--
Noncash earnings related to future payments from El Paso Corporation	--	--	25,404
Less: Interest and debt expense	127,830	81,060	41,542
Loss due to early redemptions of debt	36,846	2,434	--
Depreciation, depletion and amortization	98,846	72,126	34,778
Asset impairment charge	--	--	3,921
Cash distributions from unconsolidated affiliates	12,140	17,804	35,062
Minority interest	917	(60)	100
Net cash payment received from El Paso Corporation	8,404	7,745	7,426
Discontinued operations of Prince facilities	--	7,201	6,561
Loss on sale of Gulf of Mexico assets	--	--	11,851
Net income	$163,139	$ 97,688	$ 55,149

16. GUARANTOR FINANCIAL INFORMATION

In May 2001, we purchased our general partner's 1.01 percent non-managing interest owned in twelve of our subsidiaries for $8 million. As a result of this acquisition, all our subsidiaries, but not our equity investees, are wholly owned by us. As of December 31, 2003, our credit facility is guaranteed by each of our subsidiaries, excluding our unrestricted subsidiaries (Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.), and is collateralized by substantially all of our assets. In addition, all of our senior notes and senior subordinated notes are jointly, severally, fully and unconditionally guaranteed by us and all our subsidiaries, excluding our unrestricted subsidiaries. As of December 31, 2002, our revolving credit facility, GulfTerra Holding term credit facility, senior secured term loan and senior secured acquisition term loan are guaranteed by each of our subsidiaries, excluding our unrestricted subsidiaries (Matagorda Island Area Gathering System, Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.), and are collateralized by our general and administrative services agreement, substantially all of our assets, and our general partner's one percent general partner interest. In addition, as of December 31, 2002, all of our senior subordinated notes are jointly, severally, fully and unconditionally guaranteed by us and all our subsidiaries excluding our unrestricted subsidiaries. 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.

Non-guarantor subsidiaries for the year ended December 31, 2003, consisted of our unrestricted subsidiaries (Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.). Non-guarantor subsidiaries for the year ended December 31, 2002, consisted of Argo and Argo I for the quarter ended March 31, 2002, our GulfTerra Holding (then known as EPN Holding) subsidiaries, which owned the EPN Holding assets and equity interests in GulfTerra Holding (then known as EPN Holding), for the quarters ended June 30, 2002 and September 30, 2002, and our unrestricted subsidiaries for the quarter ended December 31, 2002. Non-guarantor subsidiaries for all other periods consisted of Argo and Argo I which owned the Prince TLP. As a result of our disposal of the Prince TLP and our related overriding royalty interest in April 2002, the results of operations and net book value of these assets are reflected as discontinued operations in our statements of income and assets held for sale in our balance sheets and Argo and Argo I became guarantor subsidiaries.

CONDENSED CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

	ISSUER	NON-GUARANTOR SUBSIDIARIES	GUARANTOR SUBSIDIARIES	CONSOLIDATING ELIMINATIONS	CONSOLIDATED TOTAL
	(IN THOUSANDS)				
Operating revenues					
Natural gas pipelines and plants					
Natural gas sales	$ --	$ --	$171,738	$ --	$171,738
NGL sales	--	--	121,167	--	121,167
Gathering and transportation	--	815	387,962	--	388,777
Processing	--	--	52,988	--	52,988
	--	815	733,855	--	734,670
Oil and NGL logistics					
Oil sales	--	--	2,231	--	2,231
Oil transportation	--	--	26,769	--	26,769
Fractionation	--	--	22,034	--	22,034
NGL Storage	--	--	2,816	--	2,816
	--	--	53,850	--	53,850
Platform services	--	--	20,861	--	20,861
Natural gas storage	--	--	44,297	--	44,297
Other -- oil and natural gas production	--	--	17,811	--	17,811
	--	815	870,674	--	871,489
Operating expenses					
Cost of natural gas and other products	--	--	287,157	--	287,157
Operation and maintenance	5,908	279	183,515	--	189,702
Depreciation, depletion and amortization	148	42	98,656	--	98,846
(Gain) loss on sale of long-lived assets	(19,000)	--	321	--	(18,679)
	(12,944)	321	569,649	--	557,026
Operating income	12,944	494	301,025	--	314,463
Earnings from consolidated affiliates	236,753	--	--	(236,753)	--
Earnings from unconsolidated affiliates	--	898	10,475	--	11,373
Minority interest expense	--	(917)	--	--	(917)
Other income	784	--	422	--	1,206
Interest and debt expense (income)	51,721	(3)	76,112	--	127,830
Loss due to early redemptions of debt	35,621	--	1,225	--	36,846

-- --------- -------- Income from continuing operations....... 163,139 478 234,585 (236,753) 161,449 Cumulative effect of accounting change................................ -- -- 1,690 -- 1,690 -------- ----- - ------- --------- -------- Net income.............................. $163,139 $ 478 $236,275 $(236,753) $163,139 ======== ===== ======== ========= ========

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2002

	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	GUARANTOR SUBSIDIARIES	CONSOLIDATING ELIMINATIONS	CONSOLIDATED TOTAL
	(IN THOUSANDS)				
Operating revenues					
Natural gas pipelines and plants					
Natural gas sales	$ --	$ 30,778	$ 54,223	$ --	$ 85,001
NGL sales	--	15,050	17,928	--	32,978
Gathering and transportation	--	71,560	122,776	--	194,336
Processing	--	5,316	39,950	--	45,266
	--	122,704	234,877	--	357,581
Oil and NGL logistics					
Oil sales	--	--	108	--	108
Oil transportation	--	--	8,364	--	8,364
Fractionation	--	--	26,356	--	26,356
NGL storage	--	--	2,817	--	2,817
	--	--	37,645	--	37,645
Platform services	--	--	16,672	--	16,672
Natural gas storage	--	2,699	25,903	--	28,602
Other -- oil and natural gas production	--	--	16,890	--	16,890
	--	125,403	331,987	--	457,390
Operating expenses					
Cost of natural gas and other products	--	39,280	69,539	--	108,819
Operation and maintenance	6,056	27,701	81,405	--	115,162
Depreciation, depletion and amortization	274	10,729	61,123	--	72,126
Loss on sale of long-lived assets	--	--	473	--	473
	6,330	77,710	212,540	--	296,580
Operating income	(6,330)	47,693	119,447	--	160,810
Earnings from consolidated affiliates	64,851	--	29,714	(94,565)	--

Earnings from unconsolidated affiliates	--	--	13,639	--	13,639
Minority interest income	--	60	--	--	60
Other income	1,471	5	61	--	1,537
Interest and debt expense (income)	(37,696)	22,048	96,708	--	81,060
Loss due to early redemptions of debt	--	--	2,434	--	2,434
Income from continuing operations	97,688	25,710	63,719	(94,565)	92,552
Income from discontinued operations	--	4,004	1,132	--	5,136
Net income	$ 97,688	$ 29,714	$ 64,851	$(94,565)	$ 97,688

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(1) Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2001

	ISSUER	NON-GUARANTOR SUBSIDIARIES	GUARANTOR SUBSIDIARIES(1)	CONSOLIDATING ELIMINATIONS	CONSOLIDATED TOTAL
	(IN THOUSANDS)				
Operating revenues					
Natural gas pipelines and plants					
Natural gas sales	$ --	$ --	$ 59,701	$ --	$ 59,701
Gathering and transportation	--	--	33,849	--	33,849
Processing	--	--	7,133	--	7,133
	--	--	100,683	--	100,683
Oil and NGL logistics					
Oil transportation	--	--	7,082	--	7,082
Fractionation	--	--	25,245	--	25,245
	--	--	32,327	--	32,327
Platform services	--	--	15,385	--	15,385
Natural gas storage	--	--	19,373	--	19,373
Other -- oil and natural gas production	--	--	25,638	--	25,638
	--	--	193,406	--	193,406
Operating expenses					
Cost of natural gas and other products	--	--	51,542	--	51,542
Operation and maintenance	(200)	--	33,479	--	33,279
Depreciation, depletion and amortization	323	--	34,455	--	34,778
Asset impairment charge	--	--	3,921	--	3,921
Loss on sale of long-lived assets	10,941	--	426	--	11,367
	11,064	--	123,823	--	134,887
Operating income (loss)	(11,064)	--	69,583	--	58,519
Earnings from consolidated affiliates	22,393	--	1,308	(23,701)	--
Earnings from unconsolidated affiliates	--	--	8,449	--	8,449
Minority interest expense	--	--	(100)	--	(100)
Other income					

28,492 -- 234 -- 28,726
Interest and debt expense
(income).......................
(15,328) -- 56,870 -- 41,542 -
------- ------ -------- ------
-- -------- Income from
continuing
operations.....................
55,149 -- 22,604 (23,701)
54,052 Income (loss) from
discontinued
operations.....................
-- 1,308 (211) -- 1,097 ------
-- ------ -------- -------- --
------ Net
income.......................
$ 55,149 $1,308 $ 22,393
$(23,701) $ 55,149 ========
====== ======== ========
========

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(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

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	--	61	43,142	--	43,203
Unbilled trade	--	52	63,015	--	63,067
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
Investments in unconsolidated affiliates	--	--	175,747	--	175,747
Investments 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	$ 113,798	$ --	$ 113,820
Affiliates	10,691	3,499	767,988	(743,308)	38,870
Accrued gas purchase costs	--	--	15,443	--	15,443
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 loans, 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 BALANCE SHEETS
DECEMBER 31, 2002

	ISSUER	NON-GUARANTOR SUBSIDIARIES	GUARANTOR SUBSIDIARIES(1)	CONSOLIDATING ELIMINATIONS	CONSOLIDATED TOTAL
	(IN THOUSANDS)				
Current assets					
Cash and cash equivalents	$ 20,777	$ --	$ 15,322	$ --	$ 36,099
Accounts receivable, net					
Trade	--	36	90,343	--	90,379
Unbilled trade	--	38	49,102	--	49,140
Affiliates	709,230	3,055	67,513	(695,972)	83,826
Other current assets	1,118	--	2,333	--	3,451
Total current assets	731,125	3,129	224,613	(695,972)	262,895
Property, plant and equipment, net	6,716	454	2,717,768	--	2,724,938
Intangible assets	--	--	3,970	--	3,970
Investments in unconsolidated affiliates	--	5,197	90,754	--	95,951
Investments in consolidated affiliates	1,787,767	--	693	(1,788,460)	--
Other noncurrent assets	205,262	--	7,879	(169,999)	43,142
Total assets	$2,730,870	$8,780	$3,045,677	$(2,654,431)	$3,130,896
Current liabilities					
Accounts payable					
Trade	$ --	$ 302	$ 119,838	$ --	$ 120,140
Affiliates	18,867	2,982	760,267	(695,972)	86,144
Accrued interest	14,221	--	807	--	15,028
Accrued gas purchase costs	--	--	6,584	--	6,584
Current maturities of senior secured term loan	5,000	--	--	--	5,000
Other current liabilities	1,645	5	19,545	--	21,195
Total current liabilities	39,733	3,289	907,041	(695,972)	254,091
Revolving credit facility	491,000	--	--	--	491,000
Senior secured term loans, less current maturities	392,500	--	160,000	--	552,500

Long-term
debt....................
857,786 -- -- -- 857,786 Other
noncurrent liabilities......
(1) -- 193,725 (169,999) 23,725
Minority
interest................. --
1,942 -- -- 1,942 Partners'
capital.................
949,852 3,549 1,784,911
(1,788,460) 949,852 ----------
------ ---------- ----------- -
--------- Total liabilities and
partners' capital.....
$2,730,870 $8,780 $3,045,677
$(2,654,431) $3,130,896
========== ====== ==========
=========== ==========

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(1) Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOW
YEAR ENDED DECEMBER 31, 2003

	ISSUER	NON-GUARANTOR SUBSIDIARIES	GUARANTOR SUBSIDIARIES	CONSOLIDATING ELIMINATIONS	CONSOLIDATED TOTAL
	(IN THOUSANDS)				
Cash flows from operating activities					
Net income	$ 163,139	$ 478	$ 236,275	$(236,753)	$ 163,139
Less cumulative effect of accounting change	--	--	1,690	--	1,690
Income from continuing operations	163,139	478	234,585	(236,753)	161,449
Adjustments to reconcile net income to net cash provided by (used in) operating activities					
Depreciation, depletion and amortization	148	42	98,656	--	98,846
Distributed earning of unconsolidated affiliates					
Earnings from unconsolidated affiliates	--	(898)	(10,475)	--	(11,373)
Distributions from unconsolidated affiliates	--	--	12,140	--	12,140
(Gain) loss on sale of long-lived assets	(19,000)	--	321	--	(18,679)
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	11,320	--	1,224	--	12,544
Amortization of debt issuance cost	7,118	--	380	--	7,498
Other noncash items	1,224	1,206	1,015	--	3,445
Working capital changes, net of acquisitions and non-cash transactions	3,193	(533)	(362)	--	2,298
Net cash provided by operating activities	167,142	295	337,484	(236,753)	268,168
Cash flows from investing activities					
Development expenditures for oil and natural gas properties	--	--	(145)	--	(145)
Additions to property, plant and equipment	(2,166)	(19)	(329,834)	--	(332,019)
Proceeds from the sale and retirement of assets	69,836	--	8,075	--	77,911
Proceeds from sale of investments in unconsolidated affiliates	--	1,355	--	--	1,355
Additions to investments in unconsolidated affiliates	--	(211)	(35,325)	--	(35,536)
Repayments on note receivable	--	1,238	--	--	1,238
Cash paid for acquisitions, net of cash acquired	--	(20)	--	--	(20)
Net cash provided by (used in) investing activities	67,670	2,343	(357,229)	--	(287,216)

------- --------- --------- Cash flows from financing activities: Net proceeds from revolving credit facility................................. 533,564 -- -- -- 533,564 Repayments of revolving credit facility..... (647,000) -- -- -- (647,000) Net proceeds from senior secured acquisition term loan................................ (23) -- -- -- (23) Repayment of senior secured acquisition term loan..................................... (237,500) -- -- -- (237,500) Repayment of GulfTerra Holding term loan.... -- -- (160,000) -- (160,000) Net proceeds from senior secured term loan..................................... 299,512 -- -- -- 299,512 Repayment of senior secured term loan....... (160,000) -- -- -- (160,000) Net proceeds from issuance of long-term debt..................................... 537,428 -- -- -- 537,426 Repayments of long-term debt................ (269,401) -- -- -- (269,401) Net proceeds from issuance of common units.................................... 509,008 -- -- -- 509,010 Redemption of Series B preference units..... (155,673) -- -- -- (155,673) Advances with affiliates................... (399,780) (1,396) 164,423 236,753 -- Distributions to partners.................. (238,397) -- -- -- (238,397) Distributions to minority interests......... -- (1,242) -- -- (1,242) Contribution from general partner........... 3,098 -- -- -- 3,098 --------- ------- --------- --------- --------- Net cash provided by (used in) financing activities............... (225,164) (2,638) 4,423 236,753 13,374 --------- ------- --------- --------- --------- Increase (decrease) in cash and cash equivalents................................ $ 9,648 $ -- $ (15,322) $ -- (5,674) ========= ======= ========= ========= Cash and cash equivalents at beginning of year....................................... 36,099 --------- Cash and cash equivalents at end of year...... $ 30,425 =========

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOW
YEAR ENDED DECEMBER 31, 2002

	ISSUER	NON-GUARANTOR SUBSIDIARIES	GUARANTOR SUBSIDIARIES(1)	CONSOLIDATING ELIMINATIONS	CONSOLIDATED TOTAL
			(IN THOUSANDS)		
Cash flows from operating activities					
Net income	$ 97,688	$ 29,714	$ 64,851	$(94,565)	$ 97,688
Less income from discontinued operations	--	4,004	1,132	--	5,136
Income from continuing operations	97,688	25,710	63,719	(94,565)	92,552
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	274	10,730	61,122	--	72,126
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	--	--	(13,639)	--	(13,639)
Distributions from unconsolidated affiliates	--	--	17,804	--	17,804
Loss on sale of long-lived assets	--	--	473	--	473
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	--	--	2,434	--	2,434
Amortization of debt issuance cost	3,449	621	373	--	4,443
Other noncash items	1,053	1,942	1,434	--	4,429
Working capital changes, net of acquisitions and non-cash transactions	16,812	(21,676)	(5,002)	--	(9,866)
Net cash provided by continuing operations	119,276	17,327	128,718	(94,565)	170,756
Net cash provided by discontinued operations	--	4,631	613	--	5,244
Net cash provided by operating activities	119,276	21,958	129,331	(94,565)	176,000
Cash flows from investing activities					
Development expenditures for oil and natural gas properties	--	--	(1,682)	--	(1,682)
Additions to property, plant and equipment	(4,619)	(9,099)	(188,823)	--	(202,541)
Proceeds from the sale and retirement of assets	--	--	5,460	--	5,460
Additions to investments in unconsolidated affiliates	--	(1,910)	(36,365)	--	(38,275)
Cash paid for acquisitions, net of cash acquired	--	(729,000)	(435,856)	--	(1,164,856)
Net cash used in investing activities of continuing operations	(4,619)	(740,009)	(657,266)	--	(1,401,894)
Net cash provided by (used in) investing activities of discontinued operations	--	(3,523)	190,000	--	186,477
Net cash used in investing activities	(4,619)	(743,532)	(467,266)	--	(1,215,417)
Cash flows from financing activities					
Net proceeds from					

revolving credit facility...... 359,219 7,000 -- -- 366,219 Repayments of revolving credit facility.......... (170,000) (7,000) -- -- (177,000) Net proceeds from GulfTerra Holding term credit facility....................................... -- 530,529 (393) -- 530,136 Repayment of GulfTerra Holding term credit facility....................................... -- (375,000) -- -- (375,000) Net proceeds from senior secured acquisition term loan.. 233,236 -- -- -- 233,236 Net proceeds from senior secured term loan....... 156,530 -- -- -- 156,530 Net proceeds from issuance of long-term debt..... 423,528 -- -- -- 423,528 Repayment of Argo term loan...................... -- -- (95,000) -- (95,000) Net proceeds from issuance of common units....... 150,159 -- -- -- 150,159 Advances with affiliates......................... (1,103,585) 581,601 427,419 94,565 -- Contributions from general partner............... 4,095 -- -- -- 4,095 Distributions to partners....................... (154,468) -- -- -- (154,468) ----------- --------- --------- --------- ---------- Net cash provided by (used in) financing activities of continuing operations............ (101,286) 737,130 332,026 94,565 1,062,435 Net cash used in financing activities of discontinued operations....................... -- (3) -- -- (3) ----------- --------- --------- --------- ----------- Net cash provided by (used in) financing activities.............................. (101,286) 737,127 332,026 94,565 1,062,432 ----------- --------- --------- --------- ----------- Increase (decrease) in cash and cash equivalents... $ 13,371 $ 15,553 $ (5,909) $ -- 23,015 =========== ========= ========= ========= Cash and cash equivalents at beginning of year..... 13,084 ----------- Cash and cash equivalents at end of year......... $ 36,099 ===========

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(1) Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW
YEAR ENDED DECEMBER 31, 2001

	ISSUER	NON-GUARANTOR SUBSIDIARIES	GUARANTOR SUBSIDIARIES(1)	CONSOLIDATING ELIMINATIONS	CONSOLIDATED TOTAL
	(IN THOUSANDS)				
Cash flows from operating activities					
Net income	$ 55,149	$ 1,308	$ 22,393	$(23,701)	$ 55,149
Less income from discontinued operations	--	1,308	(211)	--	1,097
Income from continuing operations	55,149	--	22,604	(23,701)	54,052
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	323	--	34,455	--	34,778
Asset impairment charge	--	--	3,921	--	3,921
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	--	--	(8,449)	--	(8,449)
Distributions from unconsolidated affiliates	--	--	35,062	--	35,062
Loss on sales of long-lived assets	10,941	--	426	--	11,367
Amortization of debt issuance cost	3,290	318	--	--	3,608
Other noncash items	270	--	274	--	544
Working capital changes, net of effects of acquisitions and non-cash transactions	(10,145)	385	(42,707)	--	(52,467)
Net cash provided by continuing operations	59,828	703	45,586	(23,701)	82,416
Net cash provided by discontinued operations	--	4,296	672	--	4,968
Net cash provided by operating activities	59,828	4,999	46,258	(23,701)	87,384
Cash flows from investing activities					
Development expenditures for oil and natural gas properties	--	--	(2,018)	--	(2,018)
Additions to property, plant and equipment	(896)	--	(507,451)	--	(508,347)
Proceeds from the sale and retirement of assets	89,162	--	19,964	--	109,126
Additions to investments in unconsolidated affiliates	--	--	(1,487)	--	(1,487)
Cash paid for acquisitions, net of cash acquired	--	--	(28,414)	--	(28,414)
Net cash provided by (used in) investing activities of continuing operations	88,266	--	(519,406)	--	(431,140)
Net cash used in investing activities of discontinued operations	--	(67,367)	(1,193)	--	(68,560)
Net cash provided by (used in) investing activities	88,266	(67,367)	(520,599)	--	(499,700)
Cash flows from financing activities					
Net proceeds from revolving credit facility	559,994	--	--	--	559,994
Repayments of revolving credit facility	(581,000)	--	--	--	

(581,000) Net proceeds from issuance of long-term debt..... 243,032 -- -- -- 243,032 Advances with affiliates......................... (515,198) 13,563 477,934 23,701 -- Net proceeds from issuance of common units....... 286,699 -- -- -- 286,699 Redemption of Series B preference units.......... (50,000) -- -- -- (50,000) Contributions from general partner............... 2,843 -- -- -- 2,843 Distributions to partners........................ (105,923) -- (486) -- (106,409) --------- -------- ---------- -------- --------- Net cash provided by (used in) financing activities of continuing operations............ (159,553) 13,563 477,448 23,701 355,159 Net cash provided by financing activities of discontinued operations........................ -- 49,960 -- -- 49,960 --------- -------- ---------- -------- --------- Net cash provided by (used in) financing activities.................................. (159,553) 63,523 477,448 23,701 405,119 --------- -------- ---------- -------- --------- Increase (decrease) in cash and cash equivalents... $ (11,459) $ 1,155 $ 3,107 $ -- (7,197) ========= ======== ========== ======== Cash and cash equivalents at beginning of year..... 20,281 --------- Cash and cash equivalents at end of year........... $ 13,084 =========

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(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

17. SUPPLEMENTAL OIL AND NATURAL GAS INFORMATION (UNAUDITED):

General

This footnote discusses our oil and natural gas production activities for the year 2001. The years 2003 and 2002 are not presented since these operations are not a significant part of our business as defined by SFAS No. 69, Disclosures About Oil and Gas Producing Activities, and we do not expect it to become significant in the future.

Oil and Natural Gas Reserves

The following table represents our net interest in estimated quantities of proved developed and proved undeveloped reserves of crude oil, condensate and natural gas and changes in such quantities at year end 2001. Estimates of our reserves at December 31, 2001 have been made by the independent engineering consulting firm, Netherland, Sewell & Associates, Inc. except for the Prince Field for 2001, which was prepared by El Paso Production Company, our affiliate and operator of the Prince Field. Net proved reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our policy is to recognize proved reserves only when economic producibility is supported by actual production. As a result, no proved reserves were booked with respect to any of our producing fields in the absence of actual production. Proved developed reserves are proved reserve volumes that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserve volumes that are expected to be recovered from new wells on undrilled acreage or from existing wells where a significant expenditure is required for recompletion. Reference Rules 4-10(a)(2)(i), (ii), (iii), (3) and (4) of Regulation S-X, for detailed definitions of proved reserves, which can be found at the SEC's website, http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas.

Estimates of reserve quantities are based on sound geological and engineering principles, but, by their very nature, are still estimates that are subject to substantial upward or downward revision as additional information regarding producing fields and technology becomes available.

	OIL/CONDENSATE MBBLS(1)	NATURAL GAS MMCF(1)
Proved reserves -- December 31, 2000	1,201	11,500
Revision of previous estimates	1,852	5,913
Production(2)	(345)	(4,172)
Proved reserves -- December 31, 2001	2,708	13,241
Proved developed reserves December 31, 2001(2)	2,350	10,384

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(1) Includes our overriding royalty interest in proved reserves on Garden Banks Block 73 and the Prince Field.

(2) Includes our overriding royalty interest in proved reserves of 1,341 MBbls of oil and 1,659 MMcf of natural gas on our Prince Field, which began production in 2001. These reserves were not included in proved reserves prior to 2001 because, consistent with our policy, economic producibility had not been supported by actual production. Also, we had increases in estimated proved reserves relating to our producing properties, primarily at our West Delta 35 field. Actual production in the Prince Field for 2001 was 37 MBbls of oil and 32 MMcf of natural gas.

The following are estimates of our total proved developed and proved undeveloped reserves of oil and natural gas by producing property as of December 31, 2001.

	OIL (BARRELS)		NATURAL GAS (MCF)	
	PROVED DEVELOPED	PROVED UNDEVELOPED	PROVED DEVELOPED	PROVED UNDEVELOPED
	(IN THOUSANDS)			
Garden Banks Block 72	277	--	1,900	--
Garden Banks Block 117	1,065	--	1,556	--
Viosca Knoll Block 817	12	--	2,216	2,437
West Delta Block 35	13	--	3,473	--
Prince Field	983	358	1,239	420
Total	2,350	358	10,384	2,857

In general, estimates of economically recoverable oil and natural gas reserves and of the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the subject properties, the assumed effects of regulation by governmental agencies and assumptions concerning future oil and natural gas prices, future operating costs and future plugging and abandonment costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net revenue expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The meaningfulness of such estimates is highly dependent upon the assumptions upon which they are based.

Estimates with respect to proved undeveloped reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves. A significant portion of our reserves is based upon volumetric calculations.

Future Net Cash Flows

The standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves is calculated and presented in accordance with SFAS No. 69. Accordingly, future cash inflows were determined by applying year-end oil and natural gas prices, as adjusted for fixed price contracts in effect, to our estimated share of future production from proved oil and natural gas reserves. The average prices utilized in the calculation of the standardized measure of discounted future net cash flows at December 31, 2001, were $16.75 per barrel of oil and $2.62 per Mcf of natural gas. Actual future prices and costs may be materially higher or lower. Future production and development costs were computed by applying year-end costs to future years. As we are not a taxable entity, no future income taxes were provided. A prescribed 10 percent discount factor was applied to the future net cash flows.

In our opinion, this standardized measure is not a representative measure of fair market value, and the standardized measure presented for our proved oil and natural gas reserves is not representative of the reserve value. The standardized measure is intended only to assist financial statement users in making comparisons between companies. In the table following, the amounts of future production costs have been restated to

include platform access fees paid to our platform segment. See note 2 to the table for further discussion of the impact of such fees on our consolidated standardized measure of discounted future net cash flows.

	DECEMBER 31, 2001
	(IN THOUSANDS)
Future cash inflows(1)	$ 80,603
Future production costs(2)	(19,252)
Future development costs	(10,530)
Future net cash flows	50,821
Annual discount at 10% rate	(11,761)
Standardized measure of discounted future net cash flows	$ 39,060

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(1) Our future cash inflows include estimated future receipts from our overriding royalty interest in our Prince Field and Garden Banks Block 73. Since these are overriding royalty interests, we do not participate in the production or development costs for these fields, but do include their proved reserves, production volumes and future cash inflows in our data.

(2) Our future production costs include platform access fees paid by our oil and natural gas production business to affiliated entities included in our platform services segment. Such platform access fees are eliminated in our consolidated financial statements. The future platform access fees paid to our platform segment were $4,960 for 2001. On a consolidated basis, our standardized measure of discounted future net cash flows was $43,789 for 2001.

Estimated future net cash flows for proved developed and proved undeveloped reserves as of December 31, 2001, are as follows:

	PROVED DEVELOPED	PROVED UNDEVELOPED	TOTAL
	(IN THOUSANDS)		
Undiscounted estimated future net cash flows from proved reserves before income taxes	$40,518	$10,303	$50,821
Present value of estimated future net cash flows from proved reserves before income taxes, discounted at 10%	$31,003	$ 8,057	$39,060

The following are the principal sources of change in the standardized measure:

	2001
	(IN THOUSANDS)
Beginning of year	$ 77,706
Sales and transfers of oil and natural gas produced, net of production costs	(34,834)
Net changes in prices and production costs	(55,657)
Extensions, discoveries and improved recovery, less related costs	--
Oil and natural gas development costs incurred during the year	2,018
Changes in estimated future development costs	535
Revisions of previous quantity estimates	38,090
Accretion of discount	7,771
Changes in production rates, timing and other	3,431
End of year	$ 39,060

Development, Exploration, and Acquisition Expenditures

The following table details certain information regarding costs incurred in our development, exploration, and acquisition activities during the year ended December 31:

	2001
	(IN THOUSANDS)
Development costs	$2,018
Capitalized interest	--
Total capital expenditures	$2,018

In the year presented, we elected not to incur any costs to develop our proved undeveloped reserves.

Capitalized Costs

Capitalized costs relating to our natural gas and oil producing activities and related accumulated depreciation, depletion and amortization were as follows as of December 31:

	2001
	(IN THOUSANDS)
Oil and natural gas properties	
Proved properties	$ 54,609
Wells, equipment, and related facilities	104,766
	159,375
Less accumulated depreciation, depletion and amortization	108,307
	$ 51,068

Results of operations

Results of operations from producing activities were as follows at December 31:

	2001
	(IN THOUSANDS)
Natural gas sales	$18,248
Oil, condensate, and liquid sales	8,062
Total operating revenues	26,310
Production costs(1)	16,367
Depreciation, depletion and amortization	7,567
Results of operations from producing activities	$ 2,376

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(1) These production costs include platform access fees paid to affiliated entities included in our platform services segment. Such platform access fees, which were approximately $10 million in the year presented, are eliminated in our consolidated financial statements.

18. SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION:

	QUARTER ENDED (UNAUDITED)				
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31	YEAR
	(IN THOUSANDS, EXCEPT PER UNIT DATA)				
2003					
Operating revenues(1)	$230,095	$237,031	$213,831	$190,532	$871,489
Operating income	75,107	77,886	92,079	69,391	314,463
Income from continuing operations	40,525	49,297	60,213	11,414	161,449
Cumulative effect of accounting change	1,690	--	--	--	1,690
Net income	42,215	49,297	60,213	11,414	163,139
Income allocation Series B unitholders	$ 3,876	$ 3,898	$ 4,018	$ --	$ 11,792
General partner					
Income from continuing operations	$ 14,860	$ 15,856	$ 18,031	$ 20,667	$ 69,414
Cumulative effect of accounting change	17	--	--	--	17
	$ 14,877	$ 15,856	$ 18,031	$ 20,667	$ 69,431
Common unitholders					
Income from continuing operations	$ 17,454	$ 24,160	$ 31,337	$ (7,796)	$ 65,155
Cumulative effect of accounting change	1,340	--	--	--	1,340
	$ 18,794	$ 24,160	$ 31,337	$ (7,796)	$ 66,495
Series C unitholders					
Income from continuing operations	$ 4,335	$ 5,383	$ 6,827	$ (1,457)	$ 15,088
Cumulative effect of accounting change	333	--	--	--	333
	$ 4,668	$ 5,383	$ 6,827	$ (1,457)	$ 15,421
Basic earnings per common unit					
Income from continuing operations	$ 0.40	$ 0.50	$ 0.63	$ (0.14)	$ 1.30
Cumulative effect of accounting change	0.03	--	--	--	0.03
Net income	$ 0.43	$ 0.50	$ 0.63	$ (0.14)	$ 1.33
Diluted earnings per common unit(2)					
Income from continuing operations	$ 0.40	$ 0.50	$ 0.62	$ (0.14)	$ 1.30
Cumulative effect of accounting change	0.03	--	--	--	0.02
Net income	$				

0.43 $ 0.50 $ 0.62 $ (0.14) $ 1.32
======== ======== ======== ========
======== Distributions declared and
paid per common
unit............................ $
0.675 $ 0.675 $ 0.700 $ 0.710 $
2.760 ======== ======== ========
======== ======== Basic weighted
average number of common units
outstanding.....................
44,104 48,005 50,072 57,562 49,953
======== ======== ======== ========
======== Diluted weighted average
number of common units
outstanding.....................
44,104 48,476 50,385 57,855 50,231
======== ======== ======== ========
========

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(1) Since November 2002, when we acquired the Typhoon Oil Pipeline, we have recognized revenue attributable to it using the "gross" method, which means we record as "revenues" all oil that we purchase from our customers at an index price less an amount that compensates us for our service and we record as "cost of oil" that same oil which we resell to those customers at the index price. We believe that a "net" presentation is more appropriate than a "gross" presentation and is consistent with how we evaluate the performance of the Typhoon Oil Pipeline. Based on our review of the accounting literature, we believe that generally accepted accounting principles permit us to use the "net" method, and accordingly we have presented the results of Typhoon Oil "net" for all periods. To reflect this reclassification, operating revenues have been reduced by $48.8 million, $73.1 million and $69.8 million for the quarters ended March 31, June 30 and September 30 of 2003. This change does not affect operating income or net income.

(2) As a result of the loss allocated to our common unitholders during the quarter ended December 31, 2003, the basic and diluted earnings per common units are the same.

	QUARTER ENDED (UNAUDITED)				
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31	YEAR
	(IN THOUSANDS, EXCEPT PER UNIT DATA)				
2002					
Operating revenues(1)	$ 61,544	$120,489	$122,249	$153,108	$457,390
Operating income	22,712	45,777	41,936	50,385	160,810
Income from continuing operations	14,741	28,685	23,346	25,780	92,552
Income from discontinued operations	4,385	60	456	235	5,136
Net income	19,126	28,745	23,802	26,015	97,688
Income allocation Series B unitholders	$ 3,552	$ 3,630	$ 3,693	$ 3,813	$ 14,688
General partner					
Income from continuing operations	$ 8,691	$ 10,799	$ 10,755	$ 11,837	$ 42,082
Income from discontinued operations	44	--	5	2	51
	$ 8,735	$ 10,799	$ 10,760	$ 11,839	$ 42,133
Common unitholders					
Income from continuing operations	$ 2,498	$ 14,256	$ 8,898	$ 8,623	$ 34,275
Income from discontinued operations	4,341	60	451	233	5,085
	$ 6,839	$ 14,316	$ 9,349	$ 8,856	$ 39,360
Series C unitholders	$ --	$ --	$ --	$ 1,507	$ 1,507
Basic and diluted earnings per common unit					
Income from continuing operations	$ 0.06	$ 0.33	$ 0.20	$ 0.21	$ 0.80
Income from discontinued operations	0.11	--	0.01	--	0.12
Net income	$ 0.17	$ 0.33	$ 0.21	$ 0.21	$ 0.92
Distributions declared and paid per common unit	$ 0.625	$ 0.650	$ 0.650	$ 0.675	$ 2.600
Weighted average number of common units outstanding	39,941	42,842	44,130	44,069	42,814

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(1) Operating revenues for the quarter ended December 31, 2002, have been reduced by $10.5 million to reflect the reclassification of Typhoon Oil Pipeline's cost of oil.

REPORT OF INDEPENDENT AUDITORS

To the Members of Poseidon Oil Pipeline Company, L.L.C.:

In our opinion, the accompanying balance sheets and the related statements of income, members' capital, comprehensive income and changes in accumulated other comprehensive income and cash flows present fairly, in all material respects, the financial position of Poseidon Oil Pipeline Company, L.L.C. (the "Company") at December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the financial statements, the Company has restated its statements of income and cash flows for the years ended December 31, 2002 and 2001, and its balance sheet as of December 31, 2002.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 17, 2004

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF INCOME
(IN THOUSANDS)

	FOR THE YEARS ENDED DECEMBER 31,		
	2003	2002 (RESTATED)	2001 (RESTATED)
Operating revenues			
Crude oil handling revenues	$42,573	$55,490	$70,676
Other, net	450	939	1,331
Total revenues	43,023	56,429	72,007
Operating expenses			
Crude oil handling costs	2,579	2,168	1,115
Operation and maintenance	3,694	4,691	2,077
Depreciation and amortization	8,316	8,356	10,552
	14,589	15,215	13,744
Operating income	28,434	41,214	58,263
Other income (expense)			
Interest income	56	95	394
Interest and debt expense	(5,464)	(6,923)	(7,668)
Other income	--	26,600	--
Net income	$23,026	$60,986	$50,989

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

BALANCE SHEETS
AS OF DECEMBER 31, 2003 AND 2002
(IN THOUSANDS)

	2003	2002 (RESTATED)
ASSETS		
Current assets		
Cash and cash equivalents	$ 7,950	$ 27,606
Accounts receivable		
Trade	3,396	14,040
Affiliate	1,914	2,144
Unbilled	4,354	3,614
Other current assets	3,282	2,390
Total current assets	20,896	49,794
Property, plant and equipment, net	215,195	214,497
Debt reserve fund	3,576	3,551
Other noncurrent assets	122	415
Total assets	$239,789	$268,257
LIABILITIES AND MEMBERS' CAPITAL		
Current liabilities		
Accounts payable, trade	$ 11,239	$ 10,423
Accounts payable, affiliate	1,866	5,176
Interest rate hedge liabilities	--	1,385
Total current liabilities	13,105	16,984
Revolving credit facility	123,000	148,000
Commitments and contingencies		
Members' capital		
Members' capital before accumulated other comprehensive income	103,684	104,658
Accumulated other comprehensive income	--	(1,385)
Total members' capital	103,684	103,273
Total liabilities and members' capital	$239,789	$268,257

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

FOR THE YEARS ENDED DECEMBER 31,	2003	2002 (RESTATED)	2001 (RESTATED)
Cash flows from operating activities			
Net income	$ 23,026	$ 60,986	$ 50,989
Adjustments to reconcile net income to cash provided by operating activities			
Depreciation and amortization	8,316	8,356	10,552
Amortization of debt issue costs	293	293	186
Changes in operating assets and liabilities			
(Increase) decrease in accounts receivable	10,134	(2,615)	(5,006)
(Increase) decrease in other current assets	(892)	96	99
Increase (decrease) in accounts payable	(2,494)	5,837	3,017
Decrease in reserve for revenue refund	--	--	(1,297)
Net cash provided by operating activities	38,383	72,953	58,540
Cash flows from investing activities			
Capital expenditures	(9,014)	(3,890)	(124)
Proceeds from sale of assets	--	3,400	--
(Increase) decrease in debt reserve fund	(25)	(52)	2,740
Net cash provided by (used in) investing activities	(9,039)	(542)	2,616
Cash flows from financing activities			
Repayments of long-term debt	(25,000)	(2,000)	--
Debt issue costs	--	--	(894)
Distributions to partners	(24,000)	(43,900)	(61,699)
Net cash used in financing activities	(49,000)	(45,900)	(62,593)
Increase (decrease) in cash and cash equivalents	(19,656)	26,511	(1,437)
Cash and cash equivalents:			
Beginning of period	27,606	1,095	2,532
End of period	$ 7,950	$ 27,606	$ 1,095
Supplemental disclosure of cash flow information			
Cash paid for interest, net of amounts capitalized	$ 5,034	$ 5,959	$ 6,423

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF MEMBERS' CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001
(IN THOUSANDS)

	SHELL OIL PRODUCTS U.S. (36%)	MARATHON OIL COMPANY (36%)	POSEIDON PIPELINE COMPANY, L.L.C. (28%)	TOTAL
Balance at January 1, 2001	$ 35,381	$ 35,381	$ 27,520	$ 98,282
Cash distributions	(22,212)	(22,212)	(17,275)	(61,699)
Net income	18,356	18,356	14,277	50,989
Balance at December 31, 2001	31,525	31,525	24,522	87,572
Cash distributions	(15,804)	(15,804)	(12,292)	(43,900)
Net income	21,955	21,955	17,076	60,986
Other comprehensive loss	(498)	(498)	(389)	(1,385)
Balance at December 31, 2002	37,178	37,178	28,917	103,273
Cash distributions	(8,640)	(8,640)	(6,720)	(24,000)
Net income	8,289	8,289	6,448	23,026
Other comprehensive income	498	498	389	1,385
Balance at December 31, 2003	$ 37,325	$ 37,325	$ 29,034	$103,684

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF COMPREHENSIVE INCOME AND
CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
(IN THOUSANDS)

	FOR THE YEARS ENDED DECEMBER 31,		
	2003	2002	2001
COMPREHENSIVE INCOME			
Net income	$23,026	$60,986	$50,989
Other comprehensive income (loss)	1,385	(1,385)	--
Total comprehensive income	$24,411	$59,601	$50,989
ACCUMULATED OTHER COMPREHENSIVE INCOME			
Beginning balance	$(1,385)	$ --	$ --
Unrealized net gain (loss) from interest rate swap	1,385	(1,385)	--
Ending balance	$ --	$(1,385)	$ --
ACCUMULATED OTHER COMPREHENSIVE LOSS ALLOCATED TO:			
Poseidon Pipeline Company, L.L.C.	$ --	$ (498)	$ --
Shell Oil Products U.S.	--	(498)	--
Marathon Oil Company	--	(389)	--
	$ --	$(1,385)	$ --

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

NOTES TO FINANCIAL STATEMENTS

NOTE 1 -- ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Poseidon Oil Pipeline Company, L.L.C. is a Delaware limited liability company, formed in February 1996, to design, construct, own and operate the unregulated Poseidon Pipeline extending from the Gulf of Mexico to onshore Louisiana.

Our members are Shell Oil Products U.S. (Shell), Poseidon Pipeline Company, L.L.C. (Poseidon), a subsidiary of GulfTerra Energy Partners, L.P. (formerly El Paso Energy Partners, L.P.), and Marathon Pipeline Company (Marathon), which own 36 percent, 36 percent, and 28 percent in us.

Manta Ray Gathering Company, L.L.C., a subsidiary of GulfTerra Energy Partners, L.P., and an affiliate of ours, is our operator.

The terms "we," "our" or "us", as used in these notes to financial statements, refer to Poseidon Oil Pipeline Company, L.L.C.

We are in the business of providing crude oil handling services in the Gulf of Mexico. We provide these services in accordance with various purchase and sale contracts with producers served by our pipeline. We buy crude oil at various points along the pipeline and resell the crude oil at a destination point in accordance with each individual contract. Our margin from these purchase and sale agreements is earned based upon the differential between the sales price and the purchase price and represents our earnings from providing handling services. Differences between measured purchased and sold volumes in any period are recorded as changes in exchange imbalances with producers.

Basis of Presentation

Our financial statements are prepared on the accrual basis of accounting in conformity with accounting principles generally accepted in the United States. Our financial statements for previous periods include reclassifications that were made to conform to the current year presentation. Those reclassifications have no impact on reported net income or members' capital.

Restatement of Financial Statements

We have restated our previously reported financial statements as of December 31, 2002 and for the years ended December 31, 2002 and 2001. These restatements had no effect on previously reported operating income, net income or total members' capital.

For the years ended December 31, 2002 and 2001, we have restated our crude oil handing revenues and our crude oil handling costs in our statements of income to reflect the net amounts we earn for handling services, rather than the gross amounts of oil purchased and sold under our buy/sell contracts with producers. We have also restated our accounts receivable and accounts payable balances at December 31, 2002, to give effect to this change and restated the amounts for changes in operating assets and liabilities in our statements of cash flows for the years ended December 31, 2002 and 2001. These restatements had no effect on net cash provided by operating activities. Additionally, we have reclassified the change in our debt reserve fund from a financing activity to an investing activity in our statements of cash flows for the years ended December 31, 2002 and 2001.

The effects of these changes on our previously reported financial statements for the years ended December 31, 2002 and 2001, and as of December 31, 2002 are presented below.

	2002 AS PREVIOUSLY REPORTED	2002 AS RESTATED	2001 AS PREVIOUSLY REPORTED	2001 AS RESTATED
	(IN THOUSANDS)			
Statements of Income				
Crude oil handling revenue.....................	$1,086,757	$55,490	$1,196,840	$70,676
Other revenue net(1)...........................	--	939	--	1,331
Crude oil handing costs........................	1,032,496	2,168	1,126,439	1,115
Operation and maintenance......................	4,691	4,691	1,586	2,077
Statements of Cash Flows				
(Increase) decrease in accounts receivable......	(30,141)	(2,615)	27,561	(5,006)
Increase (decrease) in accounts payable.........	33,363	5,837	(29,550)	3,017
Net cash provided by (used in) investing activities..................................	(490)	(542)	(124)	2,616
Net cash used in financing activities...........	(45,952)	(45,900)	(59,853)	(62,593)
Balance Sheet				
Accounts receivable				
Trade..	92,646	14,040		
Affiliate....................................	30,142	2,144		
Unbilled(2)..................................	--	3,614		
Accounts payable				
Trade..	84,191	10,423		
Affiliate....................................	34,398	5,176		

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(1) In prior years, we had not separately reported net results of the sales and purchases related to pipeline allowance for losses. We have reclassified these amounts to conform to our 2003 presentation.

(2) In prior years, we had not separately reported unbilled accounts receivable from trade accounts receivable. We have reclassified this amount in our 2002 balance sheet to conform to our 2003 presentation.

Cash and Cash Equivalents

We consider short-term investments with little risk of change in value because of changes in interest rates and purchased with an original maturity of less than three months to be considered cash equivalents.

Debt Reserve Fund

In connection with our revolving credit facility, we are required to maintain a debt reserve account as collateral on the outstanding balances. At December 31, 2003 and 2002, the balance in the account was approximately $3.6 million and $3.6 million, and consisted of funds earning interest at 0.7% and 1.5%.

Allowance for Doubtful Accounts

Collectibility of accounts receivable is reviewed regularly and an allowance is recorded as necessary, primarily under the specific identification method. At December 31, 2003 and 2002, no allowance for doubtful accounts was recorded.

Property, Plant and Equipment

Contributed property, plant and equipment is recorded at fair value as agreed to by the members at the date of contribution. Acquired property, plant and equipment is recorded at cost. Pipeline equipment is depreciated using a composite, straight-line method over the estimated useful lives of 3 to 30 years. Line-fill is not depreciated, as our management believes the cost of all barrels is fully recoverable. Repair and maintenance costs are expensed as incurred, while additions, improvements and replacements are capitalized. In addition, interest and other financing costs are capitalized in connection with construction as part of the cost of the asset and amortized over the related asset's estimated useful life. No gain or loss is recognized on normal asset retirements under the composite method.

Impairment and Disposal of Long-Lived Assets

We apply the provisions of Statement of Financial Accounting Standards (SFAS) No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets to account for impairment and disposal of long-lived assets. Accordingly, we evaluate the recoverability of selected long-lived assets when adverse events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. We determine the recoverability of an asset or group of assets by estimating the undiscounted cash flows expected to result from the use and eventual disposition of the asset or group of assets at the lowest level for which separate cash flows can be measured. If the total of the undiscounted cash flows is less that the carrying amount for the assets, we estimate the fair value of the asset or group of assets and recognize the amount by which the carrying value exceeds the fair value, less cost to sell, as an impairment loss in income from operations in the period the impairment is determined. As provided by the provisions of SFAS No. 144, we adopted this standard on January 1, 2002, and our adoption did not have a material impact on our financial position or result of operations.

Additionally, as required by SFAS No. 144, we classify long-lived assets to be disposed of other than by sale (e.g., abandonment, exchange or distribution) as held and used until the item is abandoned, exchanged or distributed. We evaluate assets to be disposed of other than by sale for impairment and recognize a loss for the excess of the carrying value over the fair value. Long-lived assets to be disposed of through sale recognition meeting specific criteria are classified as "Held for Sale" and measured at the lower of their cost or fair value less cost to sell. We report the results of operations of a component classified as held for sale, including any gain or loss in the period(s) in which they occur.

Debt Issue Costs

Debt issue costs are capitalized and amortized over the life of the related indebtedness. Any unamortized debt issue costs are expensed at the time the related indebtedness is repaid or terminated. As of December 31, 2003 and 2002, debt issue costs of $122 thousand and $415 thousand are classified as an other noncurrent asset on our balance sheet. Amortization of debt issue costs is included in interest and debt expense on our consolidated statements of income.

Fair Value of Financial Instruments

The estimated fair values of our cash and cash equivalents, accounts receivable and accounts payable approximate their carrying amounts in the accompanying balance sheet due to the short-term maturity of these instruments. The fair value of our long-term debt with variable interest rates approximates its carrying value because of the market-based nature of the debt's interest rates.

Revenue and Related Cost Recognition

We record crude oil handling revenue when we complete the delivery of crude oil to the agreed upon delivery point. In addition, we receive an allowance for losses of crude oil during the handling process. To the extent our actual losses are less than the allowance, we sell this excess oil and recognize revenue at the point of sale. To the extent our actual losses are greater than the allowance, we purchase oil to make-up the difference and record an expense at the point of purchase. We have presented the net results of the sales and purchases related to this pipeline allowance for losses as other, net in operating revenues.

Comprehensive Income

Our comprehensive income is determined based on net income (loss), adjusted for changes in accumulated other comprehensive income (loss) from our cash flow hedging activities associated with our interest rate hedge for our revolving credit facility.

Unbilled Accounts Receivable

Each month we record an estimate for our crude oil handling revenues and reflect the related receivables as unbilled accounts receivable. Accordingly, there is one month of estimated data recorded in our crude oil handling revenue and our accounts receivable for the years ended December 31, 2003, 2002 and 2001. Our estimate is based on actual volume and rate data through the first part of the month then extrapolated to the end of the month, adjusted according for any known or expected changes.

Crude Oil Imbalances

In the course of providing crude oil handling services for customers, we may receive quantities of crude oil that differ from the quantities committed to be delivered. These transactions result in imbalances that are settled in kind the following month. We value our imbalances based on the weighted average acquisition price of produced barrels for the current month. Our imbalance receivables and imbalance payables are classified on our balance sheet as accounts receivable and accounts payable as follows on December 31 (in thousands):

	2003	2002
Imbalance Receivables		
Trade	$ 742	$2,123
Affiliates	$ 263	$ 564
Imbalance Payables		
Trade	$2,066	$3,841
Affiliates	$ 340	$3,927

Environmental Costs

Expenditures for ongoing compliance with environmental regulations that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, and which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated.

Accounting for Hedging Activities

We apply the provisions issued in SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities to account for price risk management activities. This statement requires us to measure all derivative instruments at their fair value, and classify them as either assets or liabilities on our balance sheet, with the corresponding offset to income or other comprehensive income depending on their designation, their intended use, or their ability to qualify as hedges under the standard. In addition, we account for contracts entered into or modified after June 30, 2003, by applying the provisions of SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. This statement amends SFAS No. 133 to incorporate several interpretations of the Derivatives Implementation Group (DIG), and also makes several minor modifications to the definition of a derivative as it was defined in SFAS No. 133. There was no initial financial statement impact of adopting this standard, although the FASB and DIG continue to deliberate on the application of the standard to certain derivative contracts, which may impact our financial statements in the future.

In January 2002, we entered into a two-year interest rate swap agreement with Credit Lyonnais to fix the variable LIBOR based interest rate on $75 million of our variable rate revolving credit facility at 3.49% through January 2004. Prior to April 2003, under our credit facility, we paid an additional 1.50% over the LIBOR rate resulting in an effective interest rate of 4.99% on the hedged notional amount. Beginning in April 2003, the additional interest we pay over LIBOR was reduced to 1.25% as a result of a decrease in our leverage ratio, resulting in an effective fixed interest rate of 4.74% on the hedged notional amount. Our interest rate swap expired on January 9, 2004. Collateral was not required and we do not anticipate non-performance by the counterparty.

Income Taxes

We are organized as a Delaware limited liability company and treated as a partnership for income tax purposes, and as a result, the income or loss resulting from our operations for income tax purposes is included in the federal and state tax returns of our members. Accordingly, no provision for income taxes has been recorded in the accompanying financial statements.

Management's Use of Estimates

The preparation of our financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that effect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities that exist at the date of our financial statements. While we believe our estimates are appropriate, actual results can, and often do, differ from those estimates.

Income Allocation and Cash Distributions

Our income is allocated to our members based on their ownership percentages. At times, we may make cash distributions to our members in amounts determined by our Management Committee, which is responsible for conducting our affairs in accordance with our limited liability agreement.

Limitations of Member's Liability

As a limited liability company, our members or their affiliates are not personally liable for any of our debts, obligations or liabilities simply because they are our members.

Business Combinations

We apply the provisions of SFAS No. 141, Business Combinations to account for business combinations. This statement requires that all transactions that fit the definition of a business combination be accounted for using the purchase method. This statement also established specific criteria for the recognition of intangible assets separately from goodwill and requires unallocated negative goodwill to be written off immediately as an extraordinary item.

Accounting for Asset Retirement Obligations

We apply the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations to account for asset retirement obligations. This statement requires companies to record a liability for the estimated retirement and removal of assets used in their business. The liability is discounted to its present value, and the related asset value is increased by the amount of the resulting liability. Over the life of the asset, the liability will be accreted to its future value and eventually extinguished when the asset is taken out of service. Capitalized retirement and removal costs will be depreciated over the useful life of the related asset. As provided for by the provisions of SFAS No. 143, we adopted this standard on January 1, 2003 and our adoption of this statement did not have a material effect on our financial position or results of operations.

Reporting Gains and Losses from the Early Extinguishment of Debt

We apply the provisions of SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections to account for gains and losses from the early extinguishment of debt. Accordingly, we now evaluate the nature of any debt extinguishments to determine whether to report any gain or loss resulting from the early extinguishment of debt as an extraordinary item or as income from continuing operations.

Accounting for Costs Associated with Exit or Disposal Activities

We apply the provisions of SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities to account for costs associated with exit or disposal activities. This statement impacts any exit or disposal activities that we initiate after January 1, 2003 and we now recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. As provided for by the provisions of SFAS No. 143, we adopted this standard on January 1, 2003 and our adoption of this pronouncement did not have an effect on our financial position or results of operations.

Accounting for Guarantees

In accordance with the provisions of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, we record a liability at fair value, or otherwise disclose, certain guarantees issued after December 31, 2002, that contractually require us to make payments to a guaranteed party based on the occurrence of certain events. We do not currently guarantee the indebtedness of others; however the recognition, measurement and disclosure provisions of this interpretation will apply to any guarantees we may make in the future.

Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity

We apply the provisions of SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity to account for financial instruments with characteristics of both liabilities and equity. This statement provides guidance on the classification of financial instruments, as equity, as liabilities, or as both liabilities and equity. In accordance with the provisions of SFAS No. 150, we adopted this standard on July 1, 2003, and our adoption had no material impact on our financial statements.

NOTE 2 -- PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

	DECEMBER 31,	
	2003	2002
	(IN THOUSANDS)	
Pipeline and equipment, at cost	$265,496	$264,903
Construction work in progress	9,363	942
	274,859	265,845
Less accumulated depreciation	(59,664)	(51,348)
Total property, plant and equipment, net	$215,195	$214,497

During 2003, we capitalized interest costs of $6,500 into property, plant and equipment. During 2002, we did not capitalize interest costs into property, plant and equipment.

NOTE 3 -- LONG-TERM DEBT

As of December 31, 2003 and 2002, we had $123 million and $148 million outstanding under our $185 million revolving credit facility that matures in April 2004 with the full unused amount available. The average variable floating interest rate was 2.5% and 3.4% at December 31, 2003 and 2002. We pay a variable commitment fee on the unused portion of the credit facility. The fair value of our revolving credit facility with variable interest rates approximates its carrying value because of the market based nature of our debt's interest rates.

In January 2004, we amended our 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.

Under our amended credit facility, our interest rate is LIBOR plus 2.00% for Eurodollar loans and a variable base rate equal to the greater of the prime rate or 0.50% plus the federal funds rate (as those terms are defined in our credit agreement) plus 1.00% for Base Rate loans as defined in our credit agreement. Our interest rates will decrease by 0.25% if our leverage ratio declines to 3.00 to 1.00 or less, by 50% if our leverage ratio declines to 2.00 to 1.00 or less, or by 0.625% if our leverage ratio declines to 1.00 to 1.00 or less. Additionally, we pay commitment fees on the unused portion of the credit facility at rates that vary from 0.25% to 0.375%. This credit agreement requires us to maintain a debt service reserve equal to two times the previous quarters' interest.

Our revolving credit facility contains covenants such as restrictions on debt levels, restrictions on liens collateralizing debt and guarantees, restrictions on mergers and on the sales of assets and dividend restrictions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations.

Under our $170 million revolving credit facility, the financial debt covenants are:

(a) we must maintain consolidated tangible net worth in an amount not less than $75 million plus 100% of the net cash proceeds from our issuance of equity securities of any kind;

(b) the ratio of earnings before interest, income taxes, depreciation and amortization (EBITDA), as defined in our credit facility, to interest expense paid or accrued during the four quarters ending on the last day of the current quarter must be at least 2.50 to 1.00; and

(c) the ratio of our total indebtedness to earnings before interest, income taxes, depreciation and amortization (EBITDA), as defined in our credit facility, for the four quarters ending on the last day of the current quarter shall not exceed 4.50 to 1.00 in 2004, 3.50 to 1.00 in 2005 and 3.00 to 1.00 thereafter.

We are in compliance with the above covenants as of the date of this report.

We use interest rate swaps to limit our exposure to fluctuations in interest rates. These interest rate swaps are accounted for in accordance with SFAS No. 133. In January 2004, the two-year interest rate swap to fix the variable LIBOR based interest rate on $75 million of our revolving facility at 3.49% expired. As of December 31, 2002, the fair value of our interest rate swap was a liability of $1.4 million resulting in accumulated other comprehensive loss of $1.4 million. At December 31, 2003, the fair value of the swap was approximately zero as the swap expired January 9, 2004. The balance in accumulated other comprehensive income was also approximately zero. Additionally, we have recognized in income a realized loss of $1.7 million and $1.2 million for the years ended December 31, 2003 and 2002, as interest expense.

NOTE 4 -- MAJOR CUSTOMERS

The percentage of our crude oil handling revenues from major customers were as follows:

	FOR THE YEARS ENDED DECEMBER 31,	
	2003	2002
	% OF TOTAL REVENUES	% OF TOTAL REVENUES
Chevron Texaco Corporation	22%	9%
Marathon Oil Company(1)	18%	24%
Shell Trading formerly Equiva Trading Company(1)	13%	9%
British-Borneo USA, Inc.	9%	10%
El Paso Production(1)	3%	10%

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(1) Represents affiliated companies.

NOTE 5 -- RELATED PARTY TRANSACTIONS

We derive a portion of our revenues from our members and their affiliated companies. We generated approximately $15.0 million, $25.6 million and $28.4 million in affiliated revenue. In addition, we paid Manta Ray Gathering Company, L.L.C., a subsidiary of GulfTerra Energy Partners, approximately $2.4 million in 2003 and $2.1 million in 2002 and 2001 for management, administrative and general overhead. During 2000, we were charged and paid Shell, the then operator, an additional management fee of approximately $1.7 million associated with the repair of our ruptured pipeline. Our other members disputed this additional charge and we were subsequently reimbursed $1.6 million in 2001.

NOTE 6 -- COMMITMENTS AND CONTINGENCIES

Legal

In the normal course of business, we are involved in various legal actions arising from our operations. In the opinion of management, the outcome of these legal actions will not have a significant adverse effect on our financial position or results of operations.

Environmental

We are subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations 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 have no reserves for environmental matters, and during the next five years, we do not expect to make any significant capital expenditures relating to environmental matters.

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, regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will make accruals accordingly.

Other

We are subject to regulation under the Outer Continental Shelf Lands Act, which calls for nondiscriminatory transportation on pipelines operating in the outer continental shelf region of the Gulf of Mexico, and regulation under the Hazardous Liquid Pipeline Safety Act. Operations in offshore federal waters are regulated by the United States Department of the Interior.

In February 1998, we entered into an oil purchase and sale agreement with Pennzoil Exploration and Production (Pennzoil). The agreement provides that if Pennzoil delivers at least 7.5 million barrels by September 2003, we will refund $0.51 per barrel for all barrels delivered plus interest at 8 percent. At September 30, 2003, the barrels delivered were less than the 7.5 million barrels requirement and we believe that we have no obligation under this agreement. Also, in December 2001, we reversed our previous accrual for revenue refund of $1.7 million and recorded it as a component of crude oil handling revenue in our 2001 statement of income.

In January 2000, an anchor from a submersible drilling unit of Transocean 96 (Transocean) in tow ruptured our 24-inch crude oil pipeline north of the Ship Shoal 332 platform. The accident resulted in the release of approximately 2,200 barrels of crude oil in the waters surrounding our system, caused damage to the Ship Shoal 332 platform, and resulted in the shutdown of our system. Our cost to repair the damaged pipeline and clean up the crude oil released into the Gulf of Mexico was approximately $18 million and was charged to repair expenses in the year ended December 31, 2000. By the end of the first quarter 2000, our pipeline was repaired and placed back into service. In November 2002, we reached a settlement with multiple parties relating to this rupture and have recorded the proceeds of $26.6 million as other income in our 2002 statement of income.

(b) Pro forma financial information.

Not applicable.

(c) Exhibits.

23.1 Consent of PricewaterhouseCoopers LLP.

23.2 Consent of Netherland, Sewell & Associates, Inc.

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: April 19, 2004

By: /s/ Michael J. Knesek

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

EXHIBIT INDEX

Exhibit Number	Description
23.1	Consent of PricewaterhouseCoopers LLP.
23.2	Consent of Netherland, Sewell & Associates, Inc.

EXHIBIT 23.1

CONSENT OF INDEPENDENT ACCOUNTANTS

We consent to the incorporation by reference in the (i) Post-Effective Amendment No. 1 to Registration Statement on Form S-8 (No. 333-36856) of Enterprise Products Partners L.P.; (ii) Amendment No. 2 to Registration Statement on Form S-3 (No. 333-102778) of Enterprise Products Partners L.P. and Enterprise Products Operating L.P.; (iii) Registration Statement on Form S-8 (No. 333-82486) of Enterprise Products Partners L.P.; and (iv) Registration Statement on Form S-3 (No. 333-107073) of Enterprise Products Partners L.P., of (1) our report dated March 12, 2004 relating to the consolidated financial statements of GulfTerra Energy Partners, L.P., and (2) our report dated March 17, 2004 relating to the financial statements of Poseidon Oil Pipeline Company, L.L.C., each appearing in this Current Report on Form 8-K of Enterprise Products Partners L.P.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
April 19, 2004

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference in Enterprise Products Partners L.P.'s (i) Registration Statement No. 333-36856 of Enterprise Products Partners L.P. on Form S-8; (ii) Registration Statement No. 333-102778 of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. on Form S-3; (iii) Registration Statement No. 333-82486 of Enterprise Products Partners L.P. on Form S-8; and (iv) Registration Statement No. 333-107073 of Enterprise Products Partners L.P. on Form S-3D, of our reserve reports dated as of December 31, 2003, 2002, and 2001, each of which is included in this Current Report on Form 8-K of Enterprise Products Partners, L.P. filed with the Securities and Exchange Commission on April 19, 2004.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Frederic D. Sewell

Frederic D. Sewell
Chairman and Chief Executive Officer

Dallas, Texas
April 16, 2004