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

# FORM 10-Q

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

For the quarterly period ended June 30, 2004 or

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

For the transition period from _______ to _______.

Commission file number: 1-14323

# ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of Registrant as specified in its Charter)

| | |
|---|---|
| **Delaware** | **76-0568219** |
| (State or Other Jurisdiction of Incorporation or Organization) | (I.R.S. Employer Identification No.) |

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

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

YES [X] NO [ ]

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

YES [X] NO [ ]

There were 253,175,617 common units of *Enterprise Products Partners L.P.* outstanding at August 9, 2004. Enterprise Products Partners L.P.'s common units trade on the New York Stock Exchange under symbol "EPD."

## ENTERPRISE PRODUCTS PARTNERS L.P.
## TABLE OF CONTENTS

**Glossary**

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

| | |
|---|---|
| Acadian Gas | Acadian Gas, LLC and subsidiaries, acquired from Shell in April 2001 |
| Accum. OCI (or AOCI) | Accumulated Other Comprehensive Income or Loss, as appropriate |
| Administrative Services Agreement | First Amended and Restated Administrative Services Agreement, effective as of January 1, 2004, among EPCO, the Company, the Operating Partnership, the General Partner and the OLP General Partner (formerly, the "EPCO Agreement") |
| BBtus | Billion British thermal units, a measure of heating value |
| Bcf/d | Billion cubic feet per day |
| BEF | Belvieu Environmental Fuels L.P., a majority owned subsidiary |
| Belle Rose | Belle Rose NGL Pipeline LLC, an equity method investment |
| BRF | Baton Rouge Fractionators LLC, an equity method investment |
| BRPC | Baton Rouge Propylene Concentrator, LLC, an equity method investment |
| CEO | Chief Executive Officer |
| CFO | Chief Financial Officer |
| CMAI | Chemical Market Associates, Inc. |
| CPG | Cents per gallon |
| Diamond-Koch | Refers to common affiliates of both Valero Energy Corporation and Koch Industries, Inc. |
| Dixie | Dixie Pipeline Company, an equity method investment |
| DRIP | Distribution Reinvestment Plan |
| El Paso | El Paso Corporation and its affiliates |
| EPCO | EPCO, Inc. (formerly Enterprise Products Company), an affiliate of the Company and our ultimate parent company |
| EPIK | EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively (a former equity method investment that we acquired the remaining ownership interests in March 2003) |
| EPOLP | Enterprise Products Operating L.P., the operating subsidiary of the Company (also referred to as the "Operating Partnership") |
| Evangeline | Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively, an equity method investment |
| FASB | Financial Accounting Standards Board |
| Feedstock | A raw material required for an industrial process such as in petrochemical manufacturing |
| Forward sales contracts | The sale of a commodity or other product in a current period for delivery in a future period. |
| FTC | U.S. Federal Trade Commission |
| GAAP | Generally Accepted Accounting Principles in the United States of America |
| General Partner | Enterprise Products GP, LLC, the general partner of the Company |
| GulfTerra | GulfTerra Energy Partners, L.P. |
| GulfTerra GP | GulfTerra Energy Company, L.L.C., the general partner of GulfTerra |
| La Porte | La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively, an equity method investment |
| LIBOR | London interbank offered rate |
| MBA | Mont Belvieu Associates, see "MBA acquisition" below |
| MBA acquisition | Refers to the acquisition of Mont Belvieu Associates' remaining interest in the Mont Belvieu NGL fractionation facility in 1999 |
| MBFC | Mississippi Business Finance Corporation |
| MBPD | Thousand barrels per day |
| Mid-America | Mid-America Pipeline Company, LLC |
| Mmcf | Million cubic feet |
| Mont Belvieu | Mont Belvieu, Texas |
| Moody's | Moody's Investors Service |
| MTBE | Methyl tertiary butyl ether |

| | |
|---|---|
| Nemo | Nemo Gathering Company, LLC, an equity method investment |
| Neptune | Neptune Pipeline Company, L.L.C., an equity method investment |
| NGL or NGLs | Natural gas liquid(s) |
| NYSE | New York Stock Exchange |
| OPIS | Oil Price Information Service |
| Operating Partnership | Enterprise Products Operating L.P. and its affiliates |
| OTC | Olefins Terminal Corporation |
| Promix | K/D/S Promix LLC, an equity method investment |
| SEC | U.S. Securities and Exchange Commission |
| Seminole | Seminole Pipeline Company |
| SFAS | Statement of Financial Accounting Standards issued by the FASB |
| Shell | Shell Oil Company, its subsidiaries and affiliates |
| Splitter III | Refers to the propylene fractionation facility we acquired from Diamond-Koch |
| Starfish | Starfish Pipeline Company, LLC, an equity method investment |
| Sun | Sunoco Inc. and its affiliates |
| Throughput | Refers to the physical movement of volumes through a pipeline |
| Tri-States | Tri-States NGL Pipeline LLC, an equity method investment at March 31, 2004. On April 1, 2004, Tri-States became a 66.7% consolidated subsidiary of ours. |
| VESCO | Venice Energy Services Company, LLC, a cost method investment |
| Williams | The Williams Companies, Inc. and its affiliates |
| Wilprise | Wilprise Pipeline Company, LLC |
| 1998 Plan | EPCO's 1998 Long-Term Incentive Plan |
| 1999 Trust | EPOLP 1999 Grantor Trust, a subsidiary of EPOLP |

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

PART I. ITEM 1. FINANCIAL STATEMENTS.

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

| ASSETS | June 30, 2004 | December 31, 2003 |
|---|---|---|
| **Current Assets** | | |
| Cash and cash equivalents (includes restricted cash of $23,137 at June 30, 2004 and $13,851 at December 31, 2003) | $ 62,562 | $ 44,317 |
| Accounts and notes receivable - trade, net of allowance for doubtful accounts of $21,129 at June 30, 2004 and $20,423 at December 31, 2003 | 514,799 | 462,198 |
| Accounts receivable – related parties | 21,467 | 347 |
| Inventories | 203,796 | 150,161 |
| Prepaid and other current assets | 37,629 | 30,160 |
| Total current assets | 840,253 | 687,183 |
| **Property, Plant and Equipment, net** | 3,020,819 | 2,963,505 |
| **Investments in and Advances to Unconsolidated Affiliates** | 718,705 | 767,759 |
| **Intangible Assets, net of accumulated amortization of $48,016 at June 30, 2004 and $40,371 at December 31, 2003** | 261,248 | 268,893 |
| **Goodwill** | 82,427 | 82,427 |
| **Deferred Tax Asset** | 8,096 | 10,437 |
| **Long-term Receivables** | 5,112 | 5,454 |
| **Other Assets** | 16,947 | 17,156 |
| **Total** | $ 4,953,607 | $ 4,802,814 |
| **LIABILITIES AND PARTNERS' EQUITY** | | |
| **Current Liabilities** | | |
| Current maturities of debt | $ 364,974 | $ 240,000 |
| Accounts payable – trade | 22,025 | 68,384 |
| Accounts payable – related parties | 36,940 | 38,045 |
| Accrued gas payables | 757,656 | 622,982 |
| Accrued expenses | 17,059 | 24,695 |
| Accrued interest | 45,083 | 45,350 |
| Other current liabilities | 53,563 | 57,420 |
| Total current liabilities | 1,297,300 | 1,096,876 |
| **Long-Term Debt** | 1,402,370 | 1,899,548 |
| **Other Long-Term Liabilities** | 22,362 | 14,081 |
| **Minority Interest** | 88,823 | 86,356 |
| **Partners' Equity** | | |
| Common units (233,679,845 units outstanding at June 30, 2004 and 213,366,760 at December 31, 2003) | 1,905,148 | 1,582,951 |
| Restricted common units (81,500 units outstanding at June 30, 2004) | 1,712 | |
| Class B special units (4,413,549 units outstanding at June 30, 2004 and December 31, 2003) | 98,508 | 100,182 |
| Treasury units, at cost (546,436 units outstanding at June 30, 2004 and 798,313 units at December 31, 2003) | (11,185) | (16,519) |
| General Partner | 40,926 | 34,349 |
| Accumulated other comprehensive income | 109,315 | 4,990 |
| Deferred compensation | (1,672) | |
| Total Partners' Equity | 2,142,752 | 1,705,953 |
| **Total** | $ 4,953,607 | $ 4,802,814 |

See Notes to Unaudited Condensed Consolidated Financial Statements

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

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| **REVENUES** | | | | |
| Third parties | $ 1,510,549 | $ 1,091,308 | $ 3,060,136 | $ 2,440,090 |
| Related parties | 202,797 | 119,351 | 358,100 | 252,155 |
| Total | 1,713,346 | 1,210,659 | 3,418,236 | 2,692,245 |
| **COST AND EXPENSES** | | | | |
| Operating costs and expenses | | | | |
| Third parties | 1,426,885 | 958,999 | 2,832,868 | 2,111,301 |
| Related parties | 226,432 | 175,031 | 441,957 | 409,433 |
| Total operating costs and expenses | 1,653,317 | 1,134,030 | 3,274,825 | 2,520,734 |
| Selling, general and administrative costs | | | | |
| Third parties | 1,342 | 3,096 | 3,914 | 8,183 |
| Related parties | 5,745 | 6,957 | 12,639 | 13,341 |
| Total selling, general and administrative costs | 7,087 | 10,053 | 16,553 | 21,524 |
| Total | 1,660,404 | 1,144,083 | 3,291,378 | 2,542,258 |
| **EQUITY IN INCOME (LOSS) OF UNCONSOLIDATED AFFILIATES** | 12,109 | (228) | 25,507 | 1,393 |
| **OPERATING INCOME** | 65,051 | 66,348 | 152,365 | 151,380 |
| **OTHER INCOME (EXPENSE)** | | | | |
| Interest expense | (31,867) | (33,280) | (64,485) | (75,191) |
| Dividend income from unconsolidated affiliates | 886 | 1,794 | 2,136 | 4,395 |
| Interest income | 162 | 164 | 323 | 364 |
| Other, net | 6 | (126) | 6 | (92) |
| Other expense | (30,813) | (31,448) | (62,020) | (70,524) |
| **INCOME BEFORE PROVISION FOR INCOME TAXES, MINORITY INTEREST AND CHANGE IN ACCOUNTING PRINCIPLE** | 34,238 | 34,900 | 90,345 | 80,856 |
| **PROVISION FOR INCOME TAXES** | (419) | (476) | (2,044) | (3,605) |
| **INCOME BEFORE MINORITY INTEREST AND CHANGE IN ACCOUNTING PRINCIPLE** | 33,819 | 34,424 | 88,301 | 77,251 |
| **MINORITY INTEREST** | (744) | (1,319) | (3,698) | (3,641) |
| **INCOME BEFORE CHANGE IN ACCOUNTING PRINCIPLE** | 33,075 | 33,105 | 84,603 | 73,610 |
| **CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE** (see Note 1) | | | 7,013 | |
| **NET INCOME** | 33,075 | 33,105 | 91,616 | 73,610 |
| Cash flow hedges | 104,531 | | 104,531 | 5,354 |
| Amortization of cash flow hedges | (104) | (97) | (206) | 3,395 |
| **COMPREHENSIVE INCOME** | $ 137,502 | $ 33,008 | $ 195,941 | $ 82,359 |
| **ALLOCATION OF NET INCOME TO:** | | | | |
| Limited partners' interest in net income | $ 26,235 | $ 28,028 | $ 77,453 | $ 64,396 |
| General Partner interest in net income | $ 6,840 | $ 5,077 | $ 14,163 | $ 9,214 |
| **EARNINGS PER UNIT:** (see Note 14) | | | | |
| Basic income per unit before change in accounting principle and General Partner interest | $ 0.14 | $ 0.17 | $ 0.38 | $ 0.39 |
| Basic net income per unit, net of General Partner interest | $ 0.11 | $ 0.15 | $ 0.35 | $ 0.34 |
| Diluted income per unit before change in accounting principle and General Partner interest | $ 0.14 | $ 0.16 | $ 0.38 | $ 0.37 |
| Diluted net income per unit, net of General Partner interest | $ 0.11 | $ 0.14 | $ 0.35 | $ 0.32 |

See Notes to Unaudited Condensed Consolidated Financial Statements

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

| | For the Six Months Ended June 30, 2004 | 2003 |
|---|---|---|
| **OPERATING ACTIVITIES** | | |
| Net income | $ 91,616 | $ 73,610 |
| Adjustments to reconcile net income to cash flows provided by (used for) operating activities: | | |
| Depreciation and amortization in operating costs and expenses | 62,235 | 55,502 |
| Depreciation in selling, general and administrative costs | 155 | 49 |
| Amortization in interest expense | 1,843 | 11,915 |
| Equity in income of unconsolidated affiliates | (25,507) | (1,393) |
| Distributions received from unconsolidated affiliates | 33,721 | 20,865 |
| Cumulative effect of change in accounting principle | (7,013) | |
| Operating lease expense paid by EPCO | 4,547 | 4,502 |
| Minority interest | 3,698 | 3,641 |
| Loss (gain) on sale of assets | 115 | (32) |
| Deferred income tax expense | 2,912 | 5,464 |
| Changes in fair market value of financial instruments | 3 | (23) |
| Increase in restricted cash | (9,286) | (12,781) |
| Net effect of changes in operating accounts (see Note 11) | (51,181) | (41,067) |
| Cash provided by operating activities | 107,858 | 120,252 |
| **INVESTING ACTIVITIES** | | |
| Capital expenditures | (27,915) | (54,497) |
| Proceeds from sale of assets | 59 | 108 |
| Business combinations, net of cash received | (45,085) | (32,702) |
| Investments in and advances to unconsolidated affiliates | (1,757) | (25,058) |
| Cash used in investing activities | (74,698) | (112,149) |
| **FINANCING ACTIVITIES** | | |
| Borrowings under debt agreements | 483,000 | 1,131,210 |
| Repayments of debt | (845,000) | (1,503,000) |
| Debt issuance costs | (954) | (7,723) |
| Distributions paid to partners | (180,951) | (142,960) |
| Distributions paid to minority interests | (2,053) | (5,371) |
| Contributions from minority interests | | 5,292 |
| Contribution from General Partner related to issuance of restricted units | 35 | |
| Proceeds from issuance of common units | 411,584 | 514,251 |
| Treasury units reissued | 5,607 | |
| Settlement of cash flow hedging financial instruments | 104,531 | 5,354 |
| Financing activities cash flows | (24,201) | (2,947) |
| **NET CHANGE IN CASH AND CASH EQUIVALENTS** | 8,959 | 5,156 |
| **CASH AND CASH EQUIVALENTS, JANUARY 1** | 30,466 | 13,817 |
| **CASH AND CASH EQUIVALENTS, JUNE 30** | $ 39,425 | $ 18,973 |

See Notes to Unaudited Condensed Consolidated Financial Statements

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

| | Limited Partners | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Common units | Restricted common units | Class B special units | General Partner | Treasury units | Deferred Comp. | Accum. OCI | Total |
| Balance, January 1, 2004 | $ 1,582,951 | | $ 100,182 | $ 34,349 | $ (16,519) | | $ 4,990 | $ 1,705,953 |
| Net income | 75,928 | $ 4 | 1,521 | 14,163 | | | | 91,616 |
| Operating leases paid by EPCO | 4,368 | | 88 | 91 | | | | 4,547 |
| Cash distributions to partners | (161,714) | | (3,288) | (15,949) | | | | (180,951) |
| Proceeds from issuance of common units | 403,352 | | | 8,232 | | | | 411,584 |
| Issuance of restricted units | | 1,708 | | 35 | | $ (1,708) | | 35 |
| Amortization of deferred compensation | | | | | | 36 | | 36 |
| Treasury unit transactions: | | | | | | | | |
| - Reissued to satisfy unit options | | | | | 5,334 | | | 5,334 |
| - Gain on reissued treasury units | 263 | | 5 | 5 | | | | 273 |
| Interest rate hedging financial instruments recorded as cash flow hedges: | | | | | | | | |
| - Cash gains on settlement | | | | | | | 104,531 | 104,531 |
| - Amortization of 2003 gain as component of interest expense | | | | | | | (206) | (206) |
| Balance, June 30, 2004 | $ 1,905,148 | $ 1,712 | $ 98,508 | $ 40,926 | $ (11,185) | $ (1,672) | $ 109,315 | $ 2,142,752 |

See Notes to Unaudited Condensed Consolidated Financial Statements

## ENTERPRISE PRODUCTS PARTNERS L.P.
## NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

### 1. GENERAL

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

We were formed in April 1998 to own and operate certain NGL-related businesses of EPCO, Inc. ("EPCO," formerly Enterprise Products Company). We conduct substantially all of our business through a wholly owned subsidiary, Enterprise Products Operating L.P. (our "Operating Partnership"). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our "General Partner"). We and our General Partner are affiliates of EPCO.

In the opinion of Enterprise, the accompanying unaudited condensed consolidated financial statements include all adjustments consisting of normal recurring accruals necessary for a fair presentation. Although we believe the disclosures in these financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to the rules and regulations of the SEC. These unaudited condensed financial statements should be read in conjunction with our annual report on Form 10-K (File No. 1-14323) for the year ended December 31, 2003.

Essentially all of our assets, liabilities, revenues and expenses are recorded at the Operating Partnership level in our consolidated financial statements. We act as guarantor of certain of our Operating Partnership's debt obligations. See Note 15 for condensed financial information of our Operating Partnership.

The results of operations for the three and six month periods ended June 30, 2004 are not necessarily indicative of the results to be expected for the full year.

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

Certain reclassifications have been made to the prior year's financial statements to conform to the current year presentation.

**CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE** represents the effect of changing the method our majority owned BEF subsidiary uses to account for its planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method. These major maintenance costs, which typically result in facility shutdowns for 30 to 45 days, are principally comprised of amounts paid to third parties for materials, contract services, and other related items.

We have historically used the expense-as-incurred method for planned major maintenance activities. The change in accounting for our majority owned BEF subsidiary conforms to the Company's accounting for all planned major maintenance costs and changes the method to better reflect expenses in the period incurred. As such, we believe the change is to a method that is preferable in the circumstances.

The cumulative effect of this accounting change for years prior to 2004, which is shown separately in the Statement of Consolidated Operations and Comprehensive Income for 2004, resulted in a benefit of $7 million. See Note 14 for information regarding the effect of the accounting change on basic and diluted earnings per unit.

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

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| **Pro Forma income statement amounts:** | | | | |
| Historical net income | $ 33,075 | $ 33,105 | $ 91,616 | $ 73,610 |
| *Adjustments to derive pro forma net income:* | | | | |
| Remove historical equity in losses recorded for BEF | | 3,228 | | 6,669 |
| Record equity earnings from BEF calculated using new method of accounting for major maintenance costs | | (2,803) | | (7,225) |
| Remove cumulative effect of change in accounting principle recorded on January 1, 2004 | | | (7,013) | |
| Remove minority interest expense associated with change in accounting principle – Sun 33.3% portion | | | 2,338 | |
| Pro forma net income | $ 33,075 | $ 33,530 | $ 86,941 | $ 73,054 |
| General Partner interest | (6,840) | (5,081) | (14,069) | (9,209) |
| Pro forma net income available to limited partners | $ 26,235 | $ 28,449 | $ 72,872 | $ 63,845 |
| **Pro forma per unit data (basic):** | | | | |
| Historical units outstanding | 230,189 | 191,935 | 224,326 | 189,079 |
| Per unit data: | | | | |
| Net income before General Partner interest | $ 0.14 | $ 0.17 | $ 0.39 | $ 0.39 |
| Limited partner interest in net income | $ 0.11 | $ 0.15 | $ 0.32 | $ 0.34 |
| **Pro forma per unit data (diluted):** | | | | |
| Historical units outstanding | 230,625 | 201,935 | 224,822 | 199,079 |
| Per unit data: | | | | |
| Net income before General Partner interest | $ 0.14 | $ 0.17 | $ 0.39 | $ 0.37 |
| Limited partner interest in net income | $ 0.11 | $ 0.14 | $ 0.32 | $ 0.32 |

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

The following table shows the pro forma effects for the periods indicated.

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| Historical net income | $ 33,075 | $ 33,105 | $ 91,616 | $ 73,610 |
| Additional unit option-based compensation expense estimated using fair value-based method | (144) | (277) | (248) | (554) |
| Pro forma net income | 32,931 | 32,828 | 91,368 | 73,056 |
| Less incentive earnings allocations to General Partner | (6,305) | (4,794) | (12,582) | (8,563) |
| Pro forma net income after incentive earnings allocation | 26,626 | 28,034 | 78,786 | 64,493 |
| Multiplied by General Partner ownership interest | 2.0% | 1.0% | 2.0% | 1.0% |
| Standard earnings allocation to General Partner | $ 533 | $ 280 | $ 1,576 | $ 645 |
| | | | | |
| Incentive earnings allocation to General Partner | $ 6,305 | $ 4,794 | $ 12,582 | $ 8,563 |
| Standard earnings allocation to General Partner | 533 | 280 | 1,576 | 645 |
| General Partner interest in pro forma net income | $ 6,838 | $ 5,074 | $ 14,158 | $ 9,208 |
| | | | | |
| Pro forma net income | $ 32,931 | $ 32,828 | $ 91,368 | $ 73,056 |
| Less General Partner interest in pro forma net income | (6,838) | (5,074) | (14,158) | (9,208) |
| Pro forma net income available to limited partners | $ 26,093 | $ 27,754 | $ 77,210 | $ 63,848 |
| | | | | |
| Basic earnings per unit, net of General Partner interest: | | | | |
| Historical units outstanding | 230,189 | 191,935 | 224,326 | 189,079 |
| As reported | $ 0.11 | $ 0.15 | $ 0.35 | $ 0.34 |
| Pro forma | $ 0.11 | $ 0.14 | $ 0.34 | $ 0.34 |
| Diluted earnings per unit, net of General Partner interest: | | | | |
| Historical units outstanding | 230,625 | 201,935 | 224,822 | 199,079 |
| As reported | $ 0.11 | $ 0.14 | $ 0.35 | $ 0.32 |
| Pro forma | $ 0.11 | $ 0.14 | $ 0.34 | $ 0.32 |

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

## 2. RECENTLY ISSUED ACCOUNTING STANDARDS

*FIN 46, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51."* This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 (as amended by FIN 46R) in 2003 has had no material effect on our consolidated financial statements.

Due to the complexity of FIN 46 (as amended by FIN 46R and interpreted), the FASB is continuing to provide guidance regarding implementation issues. Since this guidance is still continuing, our conclusions regarding the application of this guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of FIN 46.

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

Currently, we account for our 13.1% investment in Venice Energy Services Company, LLC ("VESCO") using the cost method. As a result, we have recognized dividend income from VESCO to the extent that we have received cash distributions from them. In accordance with the new accounting guidance in EITF 03-16, we will record a retroactive cumulative effect adjustment equal to the difference between (i) equity earnings from VESCO that would have been recorded using the equity method in prior periods and (ii) the dividend income from VESCO that was recorded using the cost method. We are currently studying the effect that EITF 03-16 will have on our investment in VESCO; however, based on information available, we believe that the implementation of this new accounting guidance will result in an approximate $4 million gain that will be recorded as the cumulative effect of a change in accounting principle.

## 3. BUSINESS COMBINATIONS

During the first six months of 2004, we acquired an additional 16.7% membership interest in Tri-States and a 10% equity interest in Seminole. Due to the immaterial nature of each acquisition, individually and in the aggregate, our discussion of each of these transactions is limited to the following:

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

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

For the six months ended June 30, 2004, the following table shows (i) our allocation of the purchase price for acquisitions and (ii) the effects of consolidating entities that were formerly accounted for under the equity-method:

| | 16.7% interest in Tri-States | 10% interest in Seminole | Total |
|---|---|---|---|
| Cash and cash equivalents | $ 515 | | $ 515 |
| Accounts receivable | 1,801 | | 1,801 |
| Inventories | 1,943 | | 1,943 |
| Prepaid and other current assets | 3,215 | | 3,215 |
| Property, plant and equipment, net | 80,270 | $ 3,603 | 83,873 |
| Investments in and advances to unconsolidated affiliates | (42,597) | | (42,597) |
| Accounts payable | (549) | | (549) |
| Other current liabilities | (1,780) | | (1,780) |
| Minority interest | (25,818) | 24,997 | (821) |
| Total net assets recorded | 17,000 | 28,600 | 45,600 |
| Investee cash balances recorded upon consolidation | (515) | | (515) |
| Business combinations, net of cash received | $ 16,485 | $ 28,600 | $ 45,085 |

*Proposed merger with GulfTerra*

On December 15, 2003, we and certain of our affiliates, El Paso, and GulfTerra and certain of its affiliates entered into a series of agreements under which one of our wholly-owned subsidiaries and GulfTerra would merge, with GulfTerra surviving the merger and becoming a wholly-owned subsidiary of ours.

On July 29, 2004, we held a special meeting at which our common unitholders approved the issuance of Enterprise common units pursuant to the merger agreement. On the same day, GulfTerra held a special meeting of its common and Series C unitholders, at which time the merger agreement was approved and adopted. The completion of the merger remains subject to regulatory approvals, including under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, and the fulfillment or waiver of the other merger agreement closing conditions. While we cannot predict if and when all of the conditions of the proposed merger will be satisfied, we expect to complete the transaction in the third quarter of 2004.

In general, the proposed merger with GulfTerra involves the following three steps:

- *Step One.* On December 15, 2003, we purchased a 50% membership interest in GulfTerra's general partner ("GulfTerra GP") for $425 million. GulfTerra's general partner owns a 1% general partner interest in GulfTerra. This investment is accounted for using the equity method and is already recorded in our historical balance sheet at December 31, 2003. See Note 6 regarding preliminary estimates of the purchase price allocation for GulfTerra GP. This transaction is referred to as Step One of the proposed merger and will remain in effect even if the remainder of the proposed merger and post-merger transactions, which are referred to as Step Two and Step Three, do not occur.

- *Step Two.* If all necessary regulatory approvals are received and the other merger agreement conditions are either fulfilled or waived and the following steps are consummated, we will own 100% of the limited and general partner interests in GulfTerra. At that time, the proposed merger will be accounted for using the purchase method, and GulfTerra will be a consolidated subsidiary of Enterprise. Step Two of the proposed merger includes the following transactions:
  - El Paso's exchange of its remaining 50% membership interest in GulfTerra GP for a cash payment by our General Partner of $370 million (which will not be funded or reimbursed by us) and a 9.9% membership in our General Partner, and the subsequent capital contribution by our General Partner of such 50% membership interest in GulfTerra GP to us (without the receipt of additional General Partner interest, common units or other consideration).
  - Our purchase of 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units owned by El Paso for $500 million.
  - The exchange of each remaining GulfTerra common unit for 1.81 Enterprise common units, resulting in the issuance of approximately 105.1 million of our common units to GulfTerra unitholders.
- *Step Three.* Immediately after Step Two is completed, we expect to acquire certain South Texas midstream energy assets from El Paso for $150 million plus the value of then existing inventories related to such assets.

We anticipate that a portion of the purchase price at the closing of Steps Two and Three of the proposed merger will be financed with the net proceeds from our sale of 15,000,000 common units completed on August 9, 2004. We expect to finance the remaining portion of this purchase price through one or more issuances of debt securities, a temporary acquisition term facility, borrowings under our credit facility, or through any combination of the foregoing. The size, terms and timing of any future debt offerings are subject to market conditions that are beyond our control.

Our preliminary estimate of the total consideration for Steps One, Two and Three we would pay or issue is approximately $4 billion. For a period of three years following the closing of the proposed merger, at our request, El Paso will provide certain support services to GulfTerra similar to those provided by El Paso prior to the closing of the merger. GulfTerra will reimburse El Paso for 110% of its direct costs for such services (excluding any overhead costs). In addition, El Paso will make transition support payments to us in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in twelve equal monthly installments for each such year. These transition support payments are included in our preliminary estimate of total consideration.

The completion of the merger is subject to customary regulatory approvals, including under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. We are in the process of negotiating a consent decree with the FTC for the divestiture of certain of our assets to resolve their competitive concerns. We do not believe these divestitures would be significant to the combined company's business operations.

To review a copy of the merger agreement and related transaction documents, please read our Current Reports on Form 8-K filed with the SEC on December 15, 2003 and April 21, 2004.

## 4. INVENTORIES

Our inventories were as follows at the dates indicated:

| | June 30, 2004 | December 31, 2003 |
|---|---|---|
| Working inventory | $ 184,319 | $ 135,451 |
| Forward-sales inventory | 19,477 | 14,710 |
| Inventory | $ 203,796 | $ 150,161 |

Our regular trade (or "working") inventory is comprised of inventories of natural gas, NGLs and petrochemical products that are available for sale or used in the provision of services. The forward sales inventory is comprised of segregated NGL volumes dedicated to the fulfillment of forward sales contracts. Both inventories are valued at the lower of average cost or market.

Due to fluctuating conditions in the NGL, natural gas and petrochemical industry, we occasionally recognize lower of average cost or market ("LCM") adjustments when the cost of our inventories exceed their net realizable value. These non-cash adjustments are charged to operating costs and expenses in the period they are recognized. For the three months ended June 30, 2004 and 2003, we recognized $1.9 million and $4.0 million, respectively, of LCM adjustments. We recorded $6.0 million and $14.3 million of LCM adjustments for the six months ended June 30, 2004 and 2003, respectively.

## 5. PROPERTY, PLANT AND EQUIPMENT

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

| | Estimated Useful Life in Years | June 30, 2004 | December 31, 2003 |
|---|---|---|---|
| Plants and pipelines (1) | 5-35 (4) | $ 3,370,873 | $ 3,214,463 |
| Underground and other storage facilities (2) | 5-35 (5) | 289,539 | 288,199 |
| Transportation equipment (3) | 3-10 | 6,816 | 5,676 |
| Land | | 23,410 | 23,447 |
| Construction in progress | | 41,029 | 74,431 |
| Total | | 3,731,667 | 3,606,216 |
| Less accumulated depreciation | | 710,848 | 642,711 |
| Property, plant and equipment, net | | $ 3,020,819 | $ 2,963,505 |

(1) Plants and pipelines include processing plants; NGL, petrochemical and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.

(2) Underground and other storage facilities includes underground product storage caverns; storage tanks; water wells; and related assets.

(3) Transportation equipment includes vehicles and similar assets used in our operations.

(4) In general, the estimated useful lives of major components of this category are: processing plants, 20-35 years; pipelines, 3-35 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-35 years; and laboratory and shop equipment, 5-35 years.

(5) In general, the estimated useful lives of major components of this category are: underground storage wells, 30-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

Depreciation expense for the three months ended June 30, 2004 and 2003 was $27.9 million and $24.3 million, respectively. We recorded $54.7 million and $48.4 million of such expense for the six months ended June 30, 2004 and 2003, respectively.

## 6. INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES

We own interests in a number of related businesses that are accounted for using the equity or cost methods. The investments in and advances to these unconsolidated affiliates are grouped according to the business segment to which they relate. For a general discussion of business segments, see Note 13. The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated:

| | Ownership Percentage at June 30, 2004 | June 30, 2004 | December 31, 2003 |
|---|---|---|---|
| Accounted for using the equity method: | | | |
| Pipeline: | | | |
| GulfTerra GP | 50.0% | $ 424,962 | $ 424,947 |
| Neptune | 25.7% | 72,641 | 74,647 |
| Starfish | 50.0% | 39,921 | 40,664 |
| Dixie | 19.9% | 35,497 | 35,988 |
| Nemo | 33.9% | 11,880 | 12,294 |
| Belle Rose | 41.7% | 10,322 | 10,780 |
| Evangeline | 49.5% | 2,807 | 2,519 |
| Tri-States (1) | 50.0% | | 44,119 |
| Fractionation: | | | |
| Promix | 33.3% | 39,117 | 38,903 |
| BRF | 32.3% | 27,126 | 27,892 |
| BRPC | 30.0% | 16,207 | 16,584 |
| La Porte | 50.0% | 5,225 | 5,422 |
| Accounted for using the cost method: | | | |
| Processing: | | | |
| VESCO | 13.1% | 33,000 | 33,000 |
| Total | | $ 718,705 | $ 767,759 |

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

Our initial investment in Promix, La Porte, Dixie, Tri-States, Neptune, Nemo and GulfTerra GP exceeded our share of the historical cost of the underlying net assets of such entities ("excess cost"). The excess cost amounts are reflected in our investments in and advances to unconsolidated affiliates for these entities. That portion of excess cost attributable to tangible or amortizable intangible assets of each entity is amortized over the estimated useful of the underlying asset(s) as a reduction in equity earnings from the investee. That portion of excess cost attributable to goodwill or non-amortizable intangible assets is not amortized. Equity method investments, including their associated excess cost amounts, are evaluated for impairment whenever events or changes in circumstances indicate that there is a loss in value of the investment which is an other than temporary decline. The following table summarizes our excess cost information at June 30, 2004 and December 31, 2003 by the business segment to which the unconsolidated affiliates relate:

| | | **Initial Excess Cost attributable to** | | **Unamortized balance at** | |
|---|---|---|---|---|---|
| | **Amort. Periods** | **Tangible assets** | **Goodwill (1)** | **June 30, 2004** | **December 31, 2003** |
| Fractionation segment: | | | | | |
| Promix | 20 years | $ 7,955 | | $ 5,802 | $ 5,994 |
| La Porte | 35 years | 873 | | 768 | 789 |
| Pipelines segment: | | | | | |
| GulfTerra GP (2) | n/a | | $ 328,214 | 328,214 | 328,214 |
| Dixie | 35 years | 28,448 | 9,246 | 33,722 | 34,084 |
| Neptune | 35 years | 12,768 | | 11,492 | 11,674 |
| Nemo | 35 years | 727 | | 666 | 676 |
| Tri-States (3) | 35 years | 3,628 | | | 3,593 |

(1) Excess cost attributable to goodwill is not amortized; however, our investments in unconsolidated affiliates (which include excess cost amounts) are tested for impairment whenever events or circumstances indicate that there is a loss in value of the investment which is an other than temporary decline.
(2) Reflects our preliminary allocation of GulfTerra GP's $328.2 million of excess cost to goodwill.
(3) Tri-States became a consolidated subsidiary of ours in April 2004.

The Pipelines section in the preceding table includes $337.5 million of excess cost attributable to goodwill, of which $328.2 million results from our December 2003 purchase of a 50% membership interest in GulfTerra GP. The allocation of the $328.2 million of excess cost to goodwill (which represents potential intangible assets, excess of fair values over carrying values of tangible assets and remaining goodwill, if any) is preliminary pending completion of a fair value analysis which is expected to be completed during the last half of 2004. The table below shows the potential decrease in equity earnings from GulfTerra GP if certain amounts included in this excess cost were ultimately assigned to tangible or amortizable intangible assets. For purposes of calculating this sensitivity, we have applied the straight-line method of cost allocation over an estimated useful life of 20-years to various fair values.

| **Amount allocated to Tangible or Amortizable Assets out of GulfTerra GP Excess Cost Goodwill** | **Excess Cost attributed to tangible or intangible assets** | **Estimated Annual Reduction in Equity Earnings from GulfTerra GP** |
|---|---|---|
| 20% of excess cost or $65.6 million | $ 65,643 | $ 3,282 |
| 40% of excess cost or $131.3 million | 131,286 | 6,564 |
| 60% of excess cost or $196.9 million | 196,928 | 9,846 |
| 80% of excess cost or $262.6 million | 262,571 | 13,129 |
| 100% of excess cost or $328.2 million | 328,214 | 16,411 |

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

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2004** | **2003** | **2004** | **2003** |
| Pipelines: | | | | |
| GulfTerra GP (1) | $ 10,712 | | $ 21,266 | |
| Neptune | (666) | $ 684 | (1,182) | $ 694 |
| Tri-States (2) | (179) | 575 | (154) | 1,124 |
| Starfish | 1,185 | 1,335 | 2,243 | 2,484 |
| Dixie | (349) | (428) | 392 | 373 |
| Nemo | 354 | 258 | 795 | 594 |
| Belle Rose | (100) | (88) | (208) | (117) |
| Evangeline | 132 | 55 | 156 | 36 |
| EPIK (2) | | | | 1,818 |
| Wilprise (2) | | 30 | | 193 |
| Fractionation: | | | | |
| Promix | 10 | 334 | 384 | 594 |
| BRF | 690 | (61) | 1,100 | 81 |
| BRPC | 536 | 394 | 1,081 | 542 |
| La Porte | (216) | (153) | (366) | (334) |
| OTC (2) | | 65 | | (20) |
| Octane Enhancement: | | | | |
| BEF (2) | | (3,228) | | (6,669) |
| Total | $ 12,109 | $ (228) | $ 25,507 | $ 1,393 |

(1) In December 2003, we acquired a 50% membership interest in the general partner of GulfTerra Energy Partners, L.P. from El Paso.

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

The following table presents summarized income statement information for our unconsolidated affiliates accounted for using the equity method (for the periods indicated, on a 100% basis).

| | **Summarized Income Statement Information for the Three Months Ended** | | | | | |
|---|---|---|---|---|---|---|
| | **June 30, 2004** | | | **June 30, 2003** | | |
| | **Revenues** | **Operating Income** | **Net Income** | **Revenues** | **Operating Income (Loss)** | **Net Income (Loss)** |
| Pipelines: (1) | | | | | | |
| From current equity investments | $ 86,866 | $ 3,019 | $ 715 | $ 88,098 | $ 6,628 | $ 5,551 |
| From prior equity investments | (21) | (358) | (358) | 3,809 | 1,805 | 1,806 |
| Fractionation | 18,331 | 3,827 | 3,837 | 17,429 | 2,312 | 2,271 |
| Octane Enhancement (2) | | | | 40,637 | (9,713) | (9,685) |

| | **Summarized Income Statement Information for the Six Months Ended** | | | | | |
|---|---|---|---|---|---|---|
| | **June 30, 2004** | | | **June 30, 2003** | | |
| | **Revenues** | **Operating Income** | **Net Income** | **Revenues** | **Operating Income (Loss)** | **Net Income (Loss)** |
| Pipelines: (1) | | | | | | |
| From current equity investments | $ 164,394 | $ 14,181 | $ 7,358 | $ 168,355 | $ 21,850 | $ 14,494 |
| From prior equity investments | 1,926 | (243) | (243) | 15,526 | 7,510 | 7,524 |
| Fractionation | 36,884 | 8,054 | 8,059 | 35,543 | 3,836 | 3,776 |
| Octane Enhancement (2) | | | | 86,288 | (20,069) | (20,007) |

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

(2) Octane Enhancement represents our investment in a facility owned by BEF that produces motor gasoline additives to enhance octane. We increased our ownership interest in this facility from 33.3% to 66.7% on September 30, 2003. As a result, we began consolidating BEF's financial results with those of our own beginning with the fourth quarter of 2003 (BEF was an equity method investment prior to September 30, 2003). The 2004 amounts exclude BEF's consolidated results.

*Expected change in accounting method for VESCO*

As a result of newly issued accounting guidance per EITF 03-16, we changed our method of accounting for VESCO from the cost method to the equity method on July 1, 2004. The VESCO investment consists of a 13.1% membership interest in a limited liability company that owns a natural gas processing plant, NGL fractionation facilities, storage assets and gas gathering pipelines located in south Louisiana.

## 7. INTANGIBLE ASSETS AND GOODWILL

*Intangible assets*

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

| | | At June 30, 2004 | | At December 31, 2003 | |
|---|---|---|---|---|---|
| | Gross Value | Accum. Amort. | Carrying Value | Accum. Amort. | Carrying Value |
| Shell natural gas processing agreement | $ 206,216 | $ (39,586) | $ 166,630 | $ (34,063) | $ 172,153 |
| Mont Belvieu Storage II contracts | 8,127 | (581) | 7,546 | (464) | 7,663 |
| Mont Belvieu Splitter III contracts | 53,000 | (3,660) | 49,340 | (2,902) | 50,098 |
| Toca-Western natural gas processing contracts | 11,187 | (1,165) | 10,022 | (885) | 10,302 |
| Toca-Western NGL fractionation contracts | 20,042 | (2,088) | 17,954 | (1,587) | 18,455 |
| Venice contracts | 6,635 | (368) | 6,267 | (136) | 6,499 |
| Port Neches pipeline contracts | 2,400 | (496) | 1,904 | (310) | 2,090 |
| BEF UOP License Fee | 1,657 | (72) | 1,585 | (24) | 1,633 |
| Total | $ 309,264 | $ (48,016) | $ 261,248 | $ (40,371) | $ 268,893 |

All of the intangible assets noted in the preceding table are subject to amortization. Amortization expense for the three months ended June 30, 2004 and 2003 was $3.8 million and $3.6 million, respectively. We recorded $7.6 million and $7.2 million of such expense for the six months ended June 30, 2004 and 2003, respectively. For the remainder of 2004, amortization expense attributable to these intangible assets is currently estimated at $7.6 million.

*Goodwill*

The following table summarizes our goodwill amounts at June 30, 2004 and December 31, 2003 (excluding amounts included in the carrying value of unconsolidated affiliates – See Note 6).

| | Segment Affiliation | Goodwill Balance |
|---|---|---|
| Splitter III acquisition (1) | Fractionation | $ 73,690 |
| MBA acquisition (2) | Fractionation | 7,857 |
| Wilprise acquisition (3) | Pipelines | 880 |
| | | $ 82,427 |

(1) Amount recorded in connection with our acquisition of propylene fractionation assets from Diamond-Koch in February 2002.

(2) Amount recorded in connection with our acquisition of an additional interest in Mont Belvieu Associates in July 2001, which owned an interest in our Mont Belvieu NGL fractionation facility.

(3) Amount recorded in connection with our acquisition of an additional 37.4% in Wilprise in October 2003.

## 8. RELATED PARTY TRANSACTIONS

*Relationship with EPCO*

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director (and Chairman of the Board of Directors) of our General Partner. In addition, the executive and other officers of our General Partner are employees of EPCO, including O.S. Andras who is President and Chief Executive Officer and a director of the General Partner. The principal business activity of the General Partner is to act as our managing partner. Collectively, EPCO and its affiliates owned a 53.3% equity interest in Enterprise at June 30, 2004, which includes the 2% ownership interest of our General Partner (of which EPCO and its affiliates own 100%).

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

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

We and our General Partner are each separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from EPCO and its other affiliates. EPCO primarily depends on cash distributions it receives as an equity owner in us and our General Partner to fund EPCO's other operations and to meet its debt obligations. For the six months ended June 30, 2004 and 2003, EPCO received $93.9 million and $81.1 million in distributions from us and our General Partner.

*Relationship with Shell*

We have a significant commercial relationship with Shell as a partner, customer and vendor. At June 30, 2004, Shell owned an approximate 16.9% equity interest in Enterprise. Shell is one of our largest customers. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from Shell.

*Relationship with unconsolidated affiliates*

Our significant related party transactions with unconsolidated affiliates consist of the sale of natural gas to Evangeline, purchase of pipeline transportation services from Dixie and purchase of NGL storage, transportation and fractionation services from Promix. In addition, we sell natural gas to Promix.

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

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| **Revenues** | | | | |
| EPCO and affiliates | $ 75 | $ 996 | $ 2,218 | $ 1,559 |
| Shell and affiliates | 144,884 | 79,216 | 248,984 | 161,436 |
| Unconsolidated affiliates | 57,838 | 39,139 | 106,898 | 89,160 |
| **Operating costs and expenses** | | | | |
| EPCO and affiliates | 39,514 | 27,940 | 78,627 | 74,145 |
| Shell and affiliates | 180,012 | 141,227 | 346,842 | 312,941 |
| Unconsolidated affiliates | 6,906 | 5,864 | 16,488 | 22,347 |
| **Selling, general and administrative costs** | | | | |
| EPCO and affiliates | 5,745 | 6,957 | 12,639 | 13,341 |

## 9. CAPITAL STRUCTURE

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our *Third Amended and Restated Agreement of Limited Partnership* (together with all amendments thereto, the "Partnership Agreement"). Our common units trade on the NYSE under the ticker symbol "EPD." We are managed by our General Partner. Upon receipt of unitholder approval on July 29, 2004, our 4,413,549 Class B special units converted to an equal number of common units. Prior to their conversion, the Class B special units entitled the holder to the same rights and privileges (other than voting rights) as common unitholders.

Capital accounts, as defined under our Partnership Agreement, are maintained for our General Partner and our limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our consolidated financial statements.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that the limited partners and General Partner will receive. The Partnership Agreement also contains provisions for the allocation of net earnings and losses to the limited partners and the General Partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. Normal income and loss allocations according to percentage interests are done only after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated 100% to the General Partner.

*Restricted common units*

In May 2004, EPCO issued 81,500 restricted common units (or restricted units) to key management personnel of EPCO who work on our behalf as a means of retaining and compensating them for long-term performance and to increase their ownership in the Company. The fair market value of the restricted units at grant date was $1.7 million. In general, restricted unit awards entitle the recipients to acquire the underlying common units (at no cost to them) once the defined vesting period expires, subject to certain forfeiture provisions. The restricted units vest four years from the date of the grant. Unearned compensation, representing the fair market value of the restricted units at the date of issuance, is charged to earnings as compensation expense on a straight-line basis over the vesting period. During the vesting period, each holder of restricted units is entitled to receive cash distributions per unit equal to those received by our common unitholders. For basic and diluted earnings per unit purposes, restricted common units are treated as outstanding common units.

Total unamortized deferred compensation at June 30, 2004 was $1.7 million. We recorded less than $0.1 million of compensation expense for the three and six months ended June 30, 2004 that is reflected as a component of selling, general and administrative expenses. Deferred compensation is reflected as a reduction of partners' capital and is allocated 2% to our General Partner and 98% to our limited partners.

*Equity offerings*

Our partnership agreement generally authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as may be established by the General Partner in its sole discretion (subject, under certain circumstances, to the approval of our unitholders). The following table reflects the number of common units issued and the net proceeds received from each offering from January 1, 2004 through June 30, 2004:

| | | Net Proceeds from Common Unit Offerings | | |
|---|---|---|---|---|
| **Month of offering** | **Number of common units issued** | **Contributed by Limited Partners** | **Contributed by General Partner** | **Total** |
| February 2004 (1) | 1,053,861 | $ 22,684 | $ 463 | $ 23,147 |
| May 2004 (2) | 17,250,000 | 346,085 | 7,063 | 353,148 |
| May 2004 (3) | 1,757,347 | 34,583 | 706 | 35,289 |
| Total 2004 | 20,061,208 | $ 403,352 | $ 8,232 | $ 411,584 |

(1) These units were issued primarily in connection with our distribution reinvestment plan ("DRIP"). We used the proceeds from this offering for general partnership purposes.
(2) We used the proceeds from this public offering to repay the $225 million Interim Term Loan and to temporarily reduce borrowings outstanding under our revolving credit facilities.
(3) These units were issued primarily in connection with our DRIP. We used the proceeds from this offering for general partnership purposes.

During the first six months of 2004, we reissued 251,877 treasury units at a cost of $5.3 million primarily due to obligations under EPCO employee unit option agreements and recorded a $0.3 million gain on the transactions.

See Note 16 for information regarding our August 2004 equity offering of 15,000,000 common units.

*Unit History*

The following table details the outstanding balance of each class of units for the periods and at the dates indicated:

| | Limited Partners | | | |
|---|---|---|---|---|
| | **Common Units** | **Restricted Common Units** | **Class B Special Units (1)** | **Treasury Units** |
| Balance, January 1, 2004 | 213,366,760 | | 4,413,549 | 798,313 |
| Common units issued in February 2004 | 1,053,861 | | | |
| Common units issued in connection with May 2004 offering | 17,250,000 | | | |
| Other common units issued in May 2004 | 1,757,347 | | | |
| Restricted common units issued in May 2004 | | 81,500 | | |
| Treasury units reissued | 251,877 | | | (251,877) |
| Balance, June 30, 2004 | 233,679,845 | 81,500 | 4,413,549 | 546,436 |

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

## 10. DEBT OBLIGATIONS

Our debt consisted of the following at the dates indicated:

| | June 30, 2004 | December 31, 2003 |
|---|---|---|
| Borrowings under: | | |
| Interim Term Loan, variable rate, repaid in May 2004 (1) | | $ 225,000 |
| 364-Day Revolving Credit Facility, variable rate, due October 2004, $230 million borrowing capacity | | 70,000 |
| Multi-Year Revolving Credit Facility, variable rate, due November 2005, $270 million borrowing capacity (2) | $ 48,000 | 115,000 |
| Senior Notes A, 8.25% fixed rate, due March 2005 | 350,000 | 350,000 |
| Seminole Notes, 6.67% fixed rate, $15 million due in December 2004 and 2005 (3) | 30,000 | 30,000 |
| MBFC Loan, 8.70% fixed rate, due March 2010 | 54,000 | 54,000 |
| Senior Notes B, 7.50% fixed rate, due February 2011 | 450,000 | 450,000 |
| Senior Notes C, 6.375% fixed rate, due February 2013 | 350,000 | 350,000 |
| Senior Notes D, 6.875% fixed rate, due March 2033 | 500,000 | 500,000 |
| Total principal amount | 1,782,000 | 2,144,000 |
| Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt | 1,410 | 1,531 |
| Unamortized balance of decrease in fair value related to hedging a portion of fixed-rate debt | (10,146) | |
| Less unamortized discount on Senior Notes A, B, and D | (5,920) | (5,983) |
| Subtotal long-term debt | 1,767,344 | 2,139,548 |
| Less current maturities of debt (4) | (364,974) | (240,000) |
| Long-term debt (4) | $ 1,402,370 | $ 1,899,548 |
| | | |
| Standby letters of credit outstanding, $75 million of credit capacity available under our Multi-Year Revolving Credit Facility | $ 26,400 | $ 1,300 |

(1) We used the proceeds from our May 2004 common unit offering to fully repay and terminate the Interim Term Loan.
(2) This revolving credit facility has $270 million of total borrowing capacity, which is reduced by the amount of standby letters of credit outstanding.
(3) Solely as it relates to the assets of our subsidiary, Seminole Pipeline Company, our $1.8 billion in senior indebtedness at June 30, 2004 is structurally subordinated and ranks junior in right of payment to the $30 million of indebtedness of Seminole Pipeline Company.
(4) In accordance with SFAS No. 6, "Classification of Short-Term Obligations Expected to Be Refinanced," long-term and current maturities of debt at December 31, 2003 reflected our option and ability to convert any revolving credit balance outstanding at maturity under the 364-Day Revolving Credit Facility to a one-year term loan (due October 2005) in accordance with the terms of the agreement.

*Scheduled future maturities of long-term debt.* We have long and short-term payment obligations under credit agreements such as our Senior Notes and revolving credit facilities. Scheduled future maturities of debt obligations existing at June 30, 2004 were: $15 million due in 2004; $413 million due in 2005; $54 million due in 2010; $450 million due in 2011; $350 million due in 2013; and $500 million due in 2033. On May 5, 2004, we used $353.1 million in net proceeds from our May 2004 equity offering to repay the $225 million Interim Term Loan and approximately $128.1 million to temporarily reduce debt outstanding under our revolving credit facilities.

*Parent-Subsidiary guarantor relationships.* We act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Seminole Notes. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own an effective 88.4% of its capital stock).

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

*Information regarding variable interest rates paid*

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

| | **Range of interest rates paid** | **Weighted-average interest rate paid** |
|---|---|---|
| 364-Day Revolving Credit Facility | 1.72% to 4.00% | 1.79% |
| Multi-Year Revolving Credit Facility | 1.67% to 4.25% | 1.71% |
| Interim Term Loan | 1.72% to 1.78% | 1.73% |

## 11. SUPPLEMENTAL CASH FLOWS DISCLOSURE

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

| | **For the Six Months Ended June 30,** | |
|---|---|---|
| | **2004** | **2003** |
| Decrease (increase) in: | | |
| Accounts and notes receivable | $ (71,902) | $ (40,497) |
| Inventories | (51,692) | 31,467 |
| Prepaid and other current assets | (4,692) | 12,969 |
| Other assets | (125) | 235 |
| Increase (decrease) in: | | |
| Accounts payable | (48,013) | (15,803) |
| Accrued gas payable | 134,674 | (18,189) |
| Accrued expenses | (7,697) | (17,181) |
| Accrued interest | (267) | 17,160 |
| Other current liabilities | (1,198) | (10,551) |
| Other liabilities | (269) | (677) |
| Net effect of changes in operating accounts | $ (51,181) | $ (41,067) |

Cash and cash equivalents (as shown on our Statements of Consolidated Cash Flows) excludes restricted cash amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for the physical purchase of natural gas made on the NYMEX exchange. The restricted cash balance at June 30, 2004 and December 31, 2003 was $23.1 million and $13.9 million, respectively.

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

## 12. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to the variability of future earnings, cash flows and fair value of certain debt securities caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative ( or "trading") purposes.

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

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument's gains and losses offset the related results of the hedged item in the Statement of Operations and Comprehensive Income for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses on a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

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

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

*Interest rate risk hedging program*

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements (see Note 10). We assess the cash flow risk related to interest rates by identifying and measuring changes in our interest rate exposures that may impact future cash flows and evaluating hedging opportunities to manage these risks. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis to estimate the expected impact of changes in interest rates on our future cash flows. The General Partner oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

We manage a portion of our interest rate risks by utilizing interest rate swaps and similar arrangements. The objective of entering into this type of arrangement is to manage debt service costs by converting a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. In general, an interest rate swap requires one party to pay a fixed interest rate on a defined (or "notional") amount while the other party pays a variable rate based on the same notional amount. The notional amount specified in an interest rate swap agreement does not represent exposure to credit loss. We monitor our positions and the credit ratings of counterparties. Management believes the risk of incurring a credit loss on these financial instruments is remote, and that if incurred, such losses would be minimal. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt.

*Fair value hedges – Interest rate swaps.* On January 8, 2004, we entered into three interest rate swap agreements under which we exchanged the payment of fixed rate interest on a portion of principal outstanding under Senior Notes B and C for variable rate interest:

| Hedged Fixed Rate Debt | Period Covered by Swap | Termination Date of Swap | Fixed to Variable Rate (1) | Notional Amount |
|---|---|---|---|---|
| Senior Notes B, 7.50% fixed rate, due Feb. 2011 | Jan. 2004 to Feb. 2011 | Feb. 2011 | 7.50% to 4.6% | $50 million |
| Senior Notes C, 6.375% fixed rate, due Feb. 2013 | Jan. 2004 to Feb. 2013 | Feb. 2013 | 6.375% to 3.1% | $100 million |
| Senior Notes C, 6.375% fixed rate, due Feb. 2013 | Jan. 2004 to Feb. 2013 | Feb. 2013 | 6.375% to 3.1% | $100 million |

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

We have designated these interest rate swaps as fair value hedges under SFAS No. 133 since they mitigate changes in the fair value of the underlying fixed rate debt. These agreements have a combined notional amount of $250 million and match the maturity dates of the underlying debt being hedged. Under the swap agreements, we pay the counterparty a variable rate based on six-month LIBOR (plus an applicable margin) and receive back from the counterparty a fixed rate payment equal to the stated interest rate of the debt being hedged, based on the notional amounts for each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the "settlement period").

As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense. However, the interest rate swaps effectively converted a portion of the underlying fixed rate debt (i.e., the notional amounts hedged for Senior Notes B and C) into variable rate debt. As a result, interest expense will vary depending on the variable rates payable by us under terms of the swap agreements at the end of each settlement period. To the extent that the variable rate amount payable by us at the end of each settlement period is less than the fixed rate amount receivable from the counterparty, we will amortize the difference ratably to earnings as a reduction in interest expense over the settlement period. If the variable rate payable by us at the end of each settlement period is more than the fixed rate amount receivable from the counterparty, we would amortize this difference ratably to earnings as an increase in interest expense over the settlement period.

Total fair value of the interest rate swaps at June 30, 2004 was a payable of approximately $10.1 million with an offsetting increase in fair value of the underlying debt. Interest expense in our Statements of Consolidated Operations and Comprehensive Income for the three and six months ended June 30, 2004 reflect a $2 million and $3.7 million benefit, respectively, from these swaps.

*Cash flow hedges – Forward starting interest rate swaps.* On March 17, 2004, we entered into four forward starting interest rate swap transactions with original maturities of September 30, 2004. A forward starting swap is an agreement that effectively hedges the price on a specific U.S. treasury security for an established period of time. The purpose of these transactions was to effectively hedge the underlying U.S. treasury interest rate associated with our anticipated issuance of fixed rate debt, the proceeds of which would be used (either separately or in combination) to finance the GulfTerra merger, to refinance debt initially incurred to complete the merger or to refinance the indebtedness of GulfTerra (see Note 3). The forward starting interest rate swaps have been designated as cash flow hedges under SFAS No. 133. The notional amount of the anticipated debt issuances is approximately $2 billion.

On April 23, 2004, we elected to terminate these financial instruments in order to monetize the then current value of the swaps and to reduce future debt service costs. As a result, we received $104.5 million in cash from the counterparties. This amount will be amortized over the life of the anticipated debt (when issued) as a reduction to interest expense. The following table shows the portfolio of forward starting swaps categorized by the term of the underlying anticipated debt offering:

| **Term of Anticipated Debt Offering (or forecasted transaction)** | **Notional Amount of Anticipated Debt covered by Forward Starting Swaps** | **Cash Received upon Settlement of Forward Starting Swaps in April 2004** |
|---|---|---|
| 5-year, fixed rate debt instrument | $ 500.0 | $ 18.7 |
| 10-year, fixed rate debt instrument | 500.0 | 26.1 |
| 15-year, fixed rate debt instrument | 500.0 | 29.4 |
| 30-year, fixed rate debt instrument | 500.0 | 30.3 |
| Total | $ 2,000.0 | $ 104.5 |

The gain of $104.5 million in cash received was recorded as a component of AOCI in our Statement of Consolidated Partners' Equity and as an addition to comprehensive income in our Statement of Consolidated Operations and Comprehensive Income for the three and six months ended June 30, 2004.

*Commodity risk hedging program*

The prices of natural gas, NGLs, petrochemical products and MTBE are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with our Processing segment activities, we may enter into various commodity financial instruments. The primary purpose of these risk management activities is to hedge our exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

We do not hedge our exposure related to MTBE price risks. In addition, we generally do not hedge risks associated with the petrochemical marketing activities that are part of our Fractionation segment. In our Pipelines segment, we utilize a limited number of commodity financial instruments to manage the price Acadian Gas charges certain of its customers for natural gas. Lastly, we do not employ commodity financial instruments in our fee-based marketing business classified under the Other segment.

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

Our commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133 (as amended and interpreted). In those situations where the financial instrument does not qualify for hedge accounting treatment, the instrument is accounted for using mark-to-market accounting, which results in a degree of non-cash earnings volatility that is dependent upon changes in the commodity prices underlying these financial instruments. Even though these financial instruments may not qualify for hedge accounting treatment under SFAS No. 133, we view such contracts as hedges since this was the intent when we entered into such positions. Upon entering into such positions, our expectation is that the economic performance of these instruments will mitigate (or offset) the commodity risk being addressed. The specific accounting for these contracts; however, is consistent with the requirements of SFAS No. 133.

The fair value of our commodity financial instrument portfolio at June 30, 2004 and December 31, 2003 and the results of our commodity hedging activities for the three and six months ended June 30, 2004 and 2003 were both nominal amounts. During both the first half of 2004 and the first half of 2003, we utilized a limited number of commodity financial instruments.

*Effect of financial instruments on AOCI*

The following table summarizes the effect of our cash flow hedging financial instruments on accumulated other comprehensive income, or AOCI, since January 1, 2003. Information for the first six months of 2004 has been presented by quarter.

| | February 2003 Treasury Locks | April 2004 Forward-Starting Interest Rate Swaps | AOCI Total |
|---|---|---|---|
| Gain on settlement of February 2004 treasury locks | $ 5,354 | | $ 5,354 |
| Amortization of gain on settlement of cash flow hedge to interest expense | (364) | | (364) |
| Balance, January 1, 2004 | 4,990 | | 4,990 |
| Amortization of gain on settlement of cash flow hedge to interest expense | (102) | | (102) |
| Fair value of forward-starting interest rate swaps | | $ 16,973 | 16,973 |
| Balance, March 31, 2004 | 4,888 | 16,973 | 21,861 |
| Reclassification of change in fair value | | (16,973) | (16,973) |
| Gain on settlement of April 2004 forward-starting interest rate swaps | | 104,531 | 104,531 |
| Amortization of gain on settlement of cash flow hedge to interest expense | (104) | | (104) |
| Balance, June 30, 2004 | $ 4,784 | $ 104,531 | $ 109,315 |

## 13. SEGMENT INFORMATION

Operating segments are components of a business about which separate financial information is available. These components are regularly evaluated by the chief operating decision maker in deciding how to allocate resources and in assessing performance. Generally, financial information is required to be reported on the basis that it is used internally for evaluating segment performance and deciding how to allocate resources to segments.

We have five reportable business (or operating) segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. Our reportable segments are generally organized according to the type of services rendered (or process employed) and products produced and/or sold, as applicable. The segments are regularly evaluated by the CEO of the General Partner. Pipelines consists of NGL, petrochemical and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization, and propylene fractionation services. Processing includes the natural gas processing business and its related NGL marketing activities. Octane Enhancement represents our investment in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE and isobutylene). The Other business segment consists of fee-based marketing services and various operational support activities.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total (or consolidated) segment gross operating margin as operating income before: (1) depreciation and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions.

Segment revenues and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of all material intercompany (both intersegment and intrasegment) transactions.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be a supplier of raw materials or a consumer of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations. For example, we use the Promix NGL fractionator to process a portion of the mixed NGLs extracted by our gas plants. Another example is our use of the Dixie pipeline to transport propane sold to customers through our NGL marketing activities. See Note 8 for additional information regarding our related party relationships with unconsolidated affiliates.

Our revenues are derived from a wide customer base. All consolidated revenues were earned in the United States. Most of our plant-based operations are located primarily along the western Gulf Coast in Texas, Louisiana and Mississippi. Our pipelines and related operations are in a number of regions of the United States including the Gulf of Mexico offshore Louisiana (certain natural gas pipelines); the south and southeastern United States (primarily in the Texas, Louisiana and Mississippi regions); and certain regions of the central and western United States. The Mid-America pipeline system extends from the Hobbs hub located on the Texas-New Mexico border to Wyoming along one route and to Minnesota, Wisconsin and Illinois along other routes. Our marketing activities are headquartered in Houston, Texas at our main office and service customers in a number of regions in the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are allocated to each segment on the basis of each asset's or investment's principal operations. The principal reconciling item between consolidated property, plant and equipment and segment property is construction-in-progress. Segment property represents those facilities and projects that contribute to gross operating margin and is net of accumulated depreciation on these assets. Since assets under construction do not generally contribute to segment gross operating margin, these assets are not included in the operating segment totals until they are deemed operational. Consolidated intangible assets and goodwill are allocated to the segments based on the classification of the assets to which they relate.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| Revenues (1) | $ 1,713,346 | $ 1,210,659 | $ 3,418,236 | $ 2,692,245 |
| Less: Operating costs and expenses (1) | (1,653,317) | (1,134,030) | (3,274,825) | (2,520,734) |
| Add: Equity in income (loss) of unconsolidated affiliates (1) | 12,109 | (228) | 25,507 | 1,393 |
| Depreciation and amortization in operating costs and expenses (2) | 31,715 | 27,844 | 62,235 | 55,502 |
| Retained lease expense, net in operating expenses allocable to us and minority interest (3) | 2,273 | 2,274 | 4,547 | 4,547 |
| Loss (gain) on sale of assets in operating costs and expenses (2) | 17 | (36) | 115 | (32) |
| Total non-GAAP gross operating margin | $ 106,143 | $ 106,483 | $ 235,815 | $ 232,921 |

(1) These amounts are taken from our Statements of Consolidated Operations and Comprehensive Income.
(2) These non-cash expenses are taken from the operating activities section of our Statements of Consolidated Cash Flows.
(3) These non-cash expenses represent the value of the operating leases contributed by EPCO to us for which EPCO has retained the cash payment obligation (i.e., the "retained leases"). The value of the retained leases contributed directly to us is shown on our Statements of Consolidated Cash Flows under the line item titled "Operating lease expense paid by EPCO." That portion of the value contributed by a minority interest holder is a component of "Contributions from minority interests" as shown in the financing activities section of our Statement of Consolidated Cash Flows.

A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP consolidated operating income (as shown on our Statements of Consolidated Operations and Comprehensive Income) follows:

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| Operating income per GAAP | $ 65,051 | $ 66,348 | $ 152,365 | $ 151,380 |
| Adjustments to reconcile operating income per GAAP to non-GAAP total gross operating margin: | | | | |
| Depreciation and amortization in operating costs and expenses | (31,715) | (27,844) | (62,235) | (55,502) |
| Retained lease expense, net in operating costs and expenses | (2,273) | (2,274) | (4,547) | (4,547) |
| Loss (gain) on sale of assets in operating costs and expenses | (17) | 36 | (115) | 32 |
| Selling, general and administrative costs | (7,087) | (10,053) | (16,553) | (21,524) |
| Total non-GAAP gross operating margin | $ 106,143 | $ 106,483 | $ 235,815 | $ 232,921 |

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

| | Operating Segments | | | | | Adjs. and Elims. | Consol. Totals |
|---|---|---|---|---|---|---|---|
| | Fractionation | Pipelines | Processing | Octane Enhancement | Other | | |
| **Revenues from third parties:** | | | | | | | |
| Three months ended June 30, 2004 | $298,957 | $166,198 | $973,816 | $70,807 | $771 | | $1,510,549 |
| Three months ended June 30, 2003 | 195,533 | 180,383 | 714,801 | | 591 | | 1,091,308 |
| Six months ended June 30, 2004 | 526,360 | 353,951 | 2,080,123 | 98,116 | 1,586 | | 3,060,136 |
| Six months ended June 30, 2003 | 400,023 | 382,276 | 1,656,487 | | 1,304 | | 2,440,090 |
| **Revenues from related parties:** | | | | | | | |
| Three months ended June 30, 2004 | 285 | 60,591 | 141,921 | | | | 202,797 |
| Three months ended June 30, 2003 | 650 | 33,349 | 85,352 | | | | 119,351 |
| Six months ended June 30, 2004 | 570 | 112,397 | 245,133 | | | | 358,100 |
| Six months ended June 30, 2003 | 1,273 | 74,054 | 176,828 | | | | 252,155 |
| **Intersegment and intrasegment revenues:** | | | | | | | |
| Three months ended June 30, 2004 | 84,354 | 32,430 | 268,641 | 3,087 | | $(388,512) | |
| Three months ended June 30, 2003 | 57,427 | 67,963 | 151,020 | | 101 | (276,511) | |
| Six months ended June 30, 2004 | 160,358 | 67,068 | 660,252 | 4,518 | | (892,196) | |
| Six months ended June 30, 2003 | 142,099 | 103,687 | 338,261 | | 202 | (584,249) | |
| **Total revenues:** | | | | | | | |
| Three months ended June 30, 2004 | 383,596 | 259,219 | 1,384,378 | 73,894 | 771 | (388,512) | 1,713,346 |
| Three months ended June 30, 2003 | 253,610 | 281,695 | 951,173 | | 692 | (276,511) | 1,210,659 |
| Six months ended June 30, 2004 | 687,288 | 533,416 | 2,985,508 | 102,634 | 1,586 | (892,196) | 3,418,236 |
| Six months ended June 30, 2003 | 543,395 | 560,017 | 2,171,576 | | 1,506 | (584,249) | 2,692,245 |
| **Equity income (loss) in unconsolidated affiliates:** | | | | | | | |
| Three months ended June 30, 2004 | 1,020 | 11,089 | | | | | 12,109 |
| Three months ended June 30, 2003 | 579 | 2,421 | | (3,228) | | | (228) |
| Six months ended June 30, 2004 | 2,199 | 23,308 | | | | | 25,507 |
| Six months ended June 30, 2003 | 863 | 7,199 | | (6,669) | | | 1,393 |
| **Gross operating margin by individual business segment and in total:** | | | | | | | |
| Three months ended June 30, 2004 | 35,888 | 67,150 | 4,379 | (677) | (597) | | 106,143 |
| Three months ended June 30, 2003 | 35,871 | 71,969 | 2,685 | (3,228) | (814) | | 106,483 |
| Six months ended June 30, 2004 | 66,148 | 150,135 | 22,444 | (1,943) | (969) | | 235,815 |
| Six months ended June 30, 2003 | 64,918 | 143,901 | 32,641 | (6,669) | (1,870) | | 232,921 |
| **Segment assets:** | | | | | | | |
| At June 30, 2004 | 468,468 | 2,249,678 | 210,353 | 37,553 | 13,738 | 41,029 | 3,020,819 |
| At December 31, 2003 | 471,221 | 2,188,694 | 163,199 | 42,220 | 23,739 | 74,432 | 2,963,505 |
| **Investments in and advances to unconsolidated affiliates (see Note 6):** | | | | | | | |
| At June 30, 2004 | 87,675 | 598,030 | 33,000 | | | | 718,705 |
| At December 31, 2003 | 88,801 | 645,958 | 33,000 | | | | 767,759 |
| **Intangible Assets (see Note 7):** | | | | | | | |
| At June 30, 2004 | 67,294 | 9,450 | 182,919 | 1,585 | | | 261,248 |
| At December 31, 2003 | 68,553 | 9,753 | 188,954 | 1,633 | | | 268,893 |
| **Goodwill (see Note 7)** | | | | | | | |
| At June 30, 2004 and December 31, 2003 | 81,547 | 880 | | | | | 82,427 |

## 14. EARNINGS PER UNIT

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing units (i.e., common, subordinated, restricted and Class B special units) outstanding during a period. In general, diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of:

- the weighted-average number of distribution-bearing units outstanding during a period; and
- the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net operating losses, the Class A special units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. Restricted units are considered to be outstanding common units for purposes of both basic and diluted earnings per unit. Treasury units are not considered to be outstanding units; therefore, they are excluded from the computation of both basic and diluted earnings per unit.

The dilutive incremental option units are calculated in accordance with the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the beginning of each period are used to repurchase common units at average market value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

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

The amount of net income allocated to limited partner interests is derived by subtracting our General Partner's share of our net income from net income. The following table shows the allocation of net income to our General Partner for the periods indicated:

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| Net income | $ 33,075 | $ 33,105 | $ 91,616 | $ 73,610 |
| Less incentive earnings allocations to General Partner | (6,305) | (4,794) | (12,582) | (8,563) |
| Net income available after incentive earnings allocation | 26,770 | 28,311 | 79,034 | 65,047 |
| Multiplied by General Partner ownership interest (1) | 2.0% | 1.0% | 2.0% | 1.0% |
| Standard earnings allocation to General Partner | $ 535 | $ 283 | $ 1,581 | $ 651 |
| | | | | |
| Incentive earnings allocation to General Partner | $ 6,305 | $ 4,794 | $ 12,582 | $ 8,563 |
| Standard earnings allocation to General Partner | 535 | 283 | 1,581 | 651 |
| General Partner interest in net income | $ 6,840 | $ 5,077 | $ 14,163 | $ 9,214 |

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

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

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| Income before change in accounting principle and General Partner interest | $ 33,075 | $ 33,105 | $ 84,603 | $ 73,610 |
| Cumulative effect of change in accounting principle | | | 7,013 | |
| Net income | 33,075 | 33,105 | 91,616 | 73,610 |
| General Partner interest in net income | (6,840) | (5,077) | (14,163) | (9,214) |
| Limited partners' interest in net income | $ 26,235 | $ 28,028 | $ 77,453 | $ 64,396 |
| **BASIC EARNINGS PER UNIT** | | | | |
| **Numerator** | | | | |
| Income before change in accounting principle and General Partner interest | $ 33,075 | $ 33,105 | $ 84,603 | $ 73,610 |
| Cumulative effect of change in accounting principle | | | 7,013 | |
| General Partner interest in net income | (6,840) | (5,077) | (14,163) | (9,214) |
| Limited partners' interest in net income | $ 26,235 | $ 28,028 | $ 77,453 | $ 64,396 |
| **Denominator** | | | | |
| Common units outstanding | 225,744 | 166,996 | 219,897 | 160,572 |
| Restricted common units outstanding | 31 | | 15 | |
| Subordinated units outstanding | | 24,939 | | 28,507 |
| Class B special units outstanding | 4,414 | | 4,414 | |
| Total | 230,189 | 191,935 | 224,326 | 189,079 |
| **Basic earnings per unit** | | | | |
| Income per unit before change in accounting principle and General Partner interest | $ 0.14 | $ 0.17 | $ 0.38 | $ 0.39 |
| Cumulative effect of change in accounting principle | | | 0.03 | |
| General Partner interest in net income | (0.03) | (0.02) | (0.06) | (0.05) |
| Limited partners' interest in net income | $ 0.11 | $ 0.15 | $ 0.35 | $ 0.34 |
| **DILUTED EARNINGS PER UNIT** | | | | |
| **Numerator** | | | | |
| Income before change in accounting principle and General Partner interest | $ 33,075 | $ 33,105 | $ 84,603 | $ 73,610 |
| Cumulative effect of change in accounting principle | | | 7,013 | |
| General Partner interest in net income | (6,840) | (5,077) | (14,163) | (9,214) |
| Limited partners' interest in net income | $ 26,235 | $ 28,028 | $ 77,453 | $ 64,396 |
| **Denominator** | | | | |
| Common units outstanding | 225,744 | 166,996 | 219,897 | 160,572 |
| Restricted common units outstanding | 31 | | 15 | |
| Subordinated units outstanding | | 24,939 | | 28,507 |
| Class A special units outstanding | | 10,000 | | 10,000 |
| Class B special units outstanding | 4,414 | | 4,414 | |
| Incremental option units | 436 | | 496 | |
| Total | 230,625 | 201,935 | 224,822 | 199,079 |
| **Diluted earnings per unit** | | | | |
| Income per unit before change in accounting principle and General Partner interest | $ 0.14 | $ 0.16 | $ 0.38 | $ 0.37 |
| Cumulative effect of change in accounting principle | | | 0.03 | |
| General Partner interest in net income | (0.03) | (0.02) | (0.06) | (0.05) |
| Limited partners' interest in net income | $ 0.11 | $ 0.14 | $ 0.35 | $ 0.32 |

## 15. CONDENSED FINANCIAL INFORMATION OF OPERATING PARTNERSHP

The Operating Partnership and its subsidiaries conduct substantially all of our business. We have no independent operations and no material assets outside of those of the Operating Partnership. In December 2003, we restructured our General Partner's ownership interest in us and the Operating Partnership from a 1% ownership in us and 1.0101% ownership in the Operating Partnership to a 2% ownership in us. As a result, our effective ownership in the Operating Partnership increased from 98.9899% to 100%.

The Operating Partnership has outstanding publicly traded debt securities consisting of its Senior Notes A, B, C and D. We act as guarantor of all of our Operating Partnership's consolidated debt obligations (including its publicly-traded debt securities), with the exception of the Seminole Notes. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. Our guarantee of the Operating Partnership's debt obligations is full and unconditional. For additional information regarding our consolidated debt obligations, see Note 10.

The number and dollar amount of reconciling items between our consolidated financial statements and those of our Operating Partnership are insignificant. The primary reconciling items between the consolidated balance sheet of the Operating Partnership and our consolidated balance sheet are the treasury units we own directly and minority interest. The differences in consolidated net income are primarily dividends recognized by the 1999 Trust (which are eliminated in consolidation) and minority interest. The minority interest differences are attributable to the General Partner's 1.0101% ownership of the Operating Partnership prior to December 2003.

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

**Condensed Consolidated Balance Sheets**

| | June 30, 2004 | December 31, 2003 |
|---|---|---|
| **ASSETS** | | |
| Current assets | $ 841,447 | $ 687,530 |
| Property, plant and equipment, net | 3,020,819 | 2,963,505 |
| Investments in and advances to unconsolidated affiliates, net | 718,705 | 767,759 |
| Intangible assets, net | 261,248 | 268,893 |
| Goodwill | 82,427 | 82,427 |
| Deferred tax asset | 8,096 | 10,437 |
| Other assets | 22,059 | 22,610 |
| Total | $ 4,954,801 | $ 4,803,161 |
| **LIABILITIES AND PARTNERS' EQUITY** | | |
| Current liabilities | $ 1,296,856 | $ 1,093,747 |
| Long-term debt | 1,402,370 | 1,899,548 |
| Other liabilities | 22,362 | 14,081 |
| Minority interest | 91,648 | 89,216 |
| Partners' equity | 2,141,565 | 1,706,569 |
| Total | $ 4,954,801 | $ 4,803,161 |
| Total Operating Partnership debt obligations guaranteed by us | $ 1,752,000 | $ 2,114,000 |

### Condensed Consolidated Statements of Operations

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| Revenues | $ 1,713,346 | $ 1,210,659 | $ 3,418,236 | $ 2,692,245 |
| Costs and expenses | 1,660,018 | 1,144,025 | 3,290,729 | 2,541,921 |
| Equity in income (loss) of unconsolidated affiliates | 12,109 | (228) | 25,507 | 1,393 |
| Operating income | 65,437 | 66,406 | 153,014 | 151,717 |
| Other income (expense): | | | | |
| Interest expense | (31,867) | (33,281) | (64,485) | (75,192) |
| Other, net | 1,213 | 1,988 | 2,782 | 4,965 |
| Total other income (expense) | (30,654) | (31,293) | (61,703) | (70,227) |
| Income before provision for taxes, minority interest and change in accounting principle | 34,783 | 35,113 | 91,311 | 81,490 |
| Provision for taxes | (419) | (476) | (2,044) | (3,605) |
| Income before minority interest and change in accounting principle | 34,364 | 34,637 | 89,267 | 77,885 |
| Minority interest | (714) | (1,060) | (3,648) | (2,959) |
| Income before change in accounting principle | 33,650 | 33,577 | 85,619 | 74,926 |
| Cumulative effect of change in accounting principle | | | 7,013 | |
| Net income | $ 33,650 | $ 33,577 | $ 92,632 | $ 74,926 |

## 16. SUBSEQUENT EVENTS

*August 2004 equity offering*

On August 9, 2004, we sold 15,000,000 common units to the public at an offering price of $20.20 per unit. Net proceeds from this offering, including our General Partner's proportionate net capital contribution of $5.9 million, were approximately $296.9 million after deducting applicable underwriting discounts, commissions and offering expenses of $12.3 million. The net proceeds from this offering, including our General Partner's proportionate net capital contribution will be used to fund a portion of the purchase price of Steps Two and Three of the GulfTerra merger transactions and to temporarily reduce borrowings under our Multi-Year Revolving Credit Facility, or, if the proposed merger with GulfTerra (see Note 3) does not close, for working capital purposes or for future acquisitions.

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

**For the three and six months ended June 30, 2004 and 2003.**

## INTRODUCTION

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

We were formed in April 1998 to own and operate certain NGL-related businesses of EPCO, Inc. ("EPCO," formerly Enterprise Products Company). We conduct substantially all of our business through a wholly owned subsidiary, Enterprise Products Operating L.P. (our "Operating Partnership"). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our "General Partner"). We and our General Partner are affiliates of EPCO.

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

*Cautionary Statement regarding Forward-Looking Information and Risk Factors*

This quarterly report contains various forward-looking statements and information that are based on our beliefs and those of our General Partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "intend," "could," "believe," "may" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our General Partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please read our summarized "*Risk Factors*" below.

*Risk Factors*

Among the key risk factors that may have a direct impact on our results of operations and financial condition are:

- a reduction in demand for our products by the petrochemical, refining or heating industries could adversely affect our results of operations;
- a decline in the volume of NGLs delivered to our facilities could adversely affect our results of operations;
- a decrease in the difference between NGL product prices and natural gas prices may result in lower margins with respect to the margin sharing component on volumes of natural gas processed under fee-based arrangements with margin sharing mechanisms;
- our business requires extensive credit risk management that may not be adequate to protect against customer nonpayment;
- acquisitions and expansions may affect our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing our risks of being unable to effectively integrate these new operations;

- our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce distributions to our Unitholders and our ability to make payments on our debt securities;
- we have leverage that may restrict our future financial and operating flexibility;
- terrorist attacks aimed at our facilities could adversely affect our business;
- the failure to complete our proposed merger with GulfTerra; and
- the failure to realize the anticipated cost savings, synergies and other benefits of the our proposed merger with GulfTerra.

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

## RECENT DEVELOPMENTS

*Proposed merger with GulfTerra*

On December 15, 2003, we and certain of our affiliates, El Paso, and GulfTerra and certain of its affiliates entered into a series of agreements under which one of our wholly-owned subsidiaries and GulfTerra would merge, with GulfTerra surviving the merger and becoming a wholly-owned subsidiary of ours.

On July 29, 2004, we held a special meeting at which our common unitholders approved the issuance of Enterprise common units pursuant to the merger agreement and, in addition, the conversion of our Class B special units to common units. On the same day, GulfTerra held a special meeting of its common and Series C unitholders, at which the merger agreement was approved and adopted. The completion of the merger remains subject to regulatory approvals, including under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, and the fulfillment or waiver of the other merger agreement closing conditions. While we cannot predict if and when all of the conditions of the proposed merger will be satisfied, we expect to complete the transaction in the third quarter of 2004.

In general, the proposed merger with GulfTerra involves the following three steps:

- *Step One.* On December 15, 2003, we purchased a 50% membership interest in GulfTerra's general partner ("GulfTerra GP") for $425 million. GulfTerra's general partner owns a 1% general partner interest in GulfTerra. This investment is accounted for using the equity method and is already recorded in our historical balance sheet at December 31, 2003. This transaction is referred to as Step One of the proposed merger and will remain in effect even if the remainder of the proposed merger and post-merger transactions, which are referred to as Step Two and Step Three, do not occur.

- *Step Two.* If all necessary regulatory approvals are received and the other merger agreement conditions are either fulfilled or waived and the following steps are consummated, we will own 100% of the limited and general partner interests in GulfTerra. At that time, the proposed merger will be accounted for using the purchase method, and GulfTerra will be a consolidated subsidiary of Enterprise. Step Two of the proposed merger includes the following transactions:

    - El Paso's exchange of its remaining 50% membership interest in GulfTerra GP for a cash payment by our General Partner of $370 million (which will not be funded or reimbursed by us) and a 9.9% membership in our General Partner, and the subsequent capital contribution by our General Partner of such 50% membership interest in GulfTerra GP to us (without the receipt of additional General Partner interest, common units or other consideration).

    - Our purchase of 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units owned by El Paso for $500 million.

- The exchange of each remaining GulfTerra common unit for 1.81 Enterprise common units, resulting in the issuance of approximately 105.1 million of our common units to GulfTerra unitholders.

- *Step Three.* Immediately after Step Two is completed, we expect to acquire certain South Texas midstream energy assets from El Paso for $150 million plus the value of then existing inventories related to such assets.

We anticipate that a portion of the purchase price at the closing of Steps Two and Three of the proposed merger will be financed with the net proceeds from our sale of 15,000,000 common units completed on August 9, 2004. We expect to finance the remaining portion of this purchase price through one or more issuances of debt securities, a temporary acquisition term facility, borrowings under our credit facility, or through any combination of the foregoing. The size, terms and timing of any future debt offerings are subject to market conditions that are beyond our control.

Our preliminary estimate of the total consideration for Steps One, Two and Three we would pay or issue is approximately $4 billion. For a period of three years following the closing of the proposed merger, at our request, El Paso will provide certain support services to GulfTerra similar to those provided by El Paso prior to the closing of the merger. GulfTerra will reimburse El Paso for 110% of its direct costs for such services (excluding any overhead costs). In addition, El Paso will make transition support payments to us in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in twelve equal monthly installments for each such year. These transition support payments are included in our preliminary estimate of total consideration.

The completion of the merger is subject to customary regulatory approvals, including under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. We are in the process of negotiating a consent decree with the FTC for the divestiture of certain of our assets to resolve their competitive concerns. We do not believe these divestitures would be significant to the combined company's business operations.

To review a copy of the merger agreement and related transaction documents, please read our Current Reports on Form 8-K filed with the SEC on December 15, 2003 and April 21, 2004.

*Launch of Tender Offer for GulfTerra Senior Subordinated and Senior Notes*

On August 4, 2004, our Operating Partnership commenced four cash tender offers to purchase for an estimated price of approximately $1.1 billion any and all of the outstanding senior subordinated and senior notes of GulfTerra, having a total outstanding principal amount of approximately $921.5 million, and solicitations of consents to amend the indentures governing those notes. The four tender offers are for the following GulfTerra senior debt obligations:

- $215.9 million 8.5% Senior Subordinated Notes due 2010;
- $321.6 million 8.5% Senior Subordinated Notes due 2011;
- $134 million 10.625% Senior Subordinated Notes due 2012; and
- $250 million 6.25% Senior Notes due 2010.

We commenced the tender offers and consent solicitations in anticipation of completing the proposed merger with GulfTerra in the third quarter of 2004, and the closing of the merger is a non-waivable condition to the completion of the tender offers. Other conditions include our raising funds sufficient to pay for the tendered notes. The purpose of the tender offers is to acquire all of GulfTerra's outstanding senior subordinated and senior notes, and the purpose of the consent solicitations is to eliminate substantially all of the covenants and several events of default in each indenture. This would provide the combined company with additional flexibility to pursue its operating and financing activities following the merger. We believe that after the merger is completed, we will be able to issue debt securities in the capital markets with covenants significantly less restrictive than those contained in the indentures governing these notes.

In addition to the tender offers consideration, we will also pay accrued and unpaid interest up to but not including, the settlement date on all notes accepted in the offer. The settlement date is promptly after the expiration date of September 2, 2004. The consent date is August 13, 2004. The approximate $1.1 billion purchase cost for the notes will be recorded as part of our consideration paid to consummate the merger with GulfTerra.

*Amendments to natural gas processing agreements*

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

As a result of this effort, approximately two-thirds of the 2.1 Bcf/d of natural gas we processed during the second quarter of 2004 was under processing agreements containing a fee-based component. This compares to approximately 50 MMcf/d of fee-based volumes prior to amending these agreements. The remaining one-third, or 0.7 Bcf/d, was processed primarily under percent-of-liquids agreements compared to 0.5 Bcf/d under such arrangements previously. The new percent-of-liquids agreements resulted in approximately 1 MBPD of additional equity NGL production during the second quarter of 2004.

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

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

*Interest Rate Hedging Program*

In March 2004, we entered into forward starting interest rate swaps in anticipation of future issuances of fixed rate debt, the proceeds of which would be used (either separately or in combination) to finance the GulfTerra merger, to refinance debt initially incurred to complete the merger or to refinance the indebtedness of GulfTerra. In late April 2004, we terminated these arrangements and received approximately $104.5 million in cash, which was used to temporarily reduce amounts outstanding under our revolving credit facilities. This amount will be amortized to earnings (from AOCI) over the life of the anticipated debt (when issued) as a reduction to interest expense. For additional information regarding these financial instruments, please read "*Interest rate risk*" included under Item 3 of this quarterly report.

*Equity offerings*

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

On August 9, 2004, we sold 15,000,000 common units to the public at an offering price of $20.20 per unit. Net proceeds from this offering, including our General Partner's proportionate net capital contribution of $5.9 million, were approximately $296.9 million after deducting applicable underwriting discounts, commissions and offering expenses of $12.3 million. The net proceeds from this offering, including our General Partner's proportionate net capital contribution will be used to fund a portion of the purchase price of Steps Two and Three of the GulfTerra merger transactions and to temporarily reduce borrowings under our Multi-Year Revolving Credit Facility, or, if the proposed merger with GulfTerra does not close, for working capital purposes or for future acquisitions.

## OUR RESULTS OF OPERATIONS

We have five reportable business (or operating) segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. Pipelines consists of NGL, petrochemical and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization and propylene fractionation. Processing includes our natural gas processing business and related NGL marketing activities. Octane Enhancement represents our investment in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE and isobutylene). The Other business segment consists of fee-based marketing services and various operational support activities.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total (or consolidated) segment gross operating margin as operating income before: (1) depreciation and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be a supplier of raw materials or a consumer of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations. For additional information regarding our business segments, please read Note 13 of our Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2004** | **2003** | **2004** | **2003** |
| Revenues | $1,713,346 | $ 1,210,659 | $3,418,236 | $ 2,692,245 |
| Operating costs and expenses | 1,653,317 | 1,134,030 | 3,274,825 | 2,520,734 |
| Selling, general and administrative costs | 7,087 | 10,053 | 16,553 | 21,524 |
| Equity in income (loss) of unconsolidated affiliates | 12,109 | (228) | 25,507 | 1,393 |
| Operating income | 65,051 | 66,348 | 152,365 | 151,380 |

A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP consolidated operating income (as shown on our Statements of Consolidated Operations and Comprehensive Income) follows:

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2004** | **2003** | **2004** | **2003** |
| Operating income per GAAP | $ 65,051 | $ 66,348 | $ 152,365 | $ 151,380 |
| Adjustments to reconcile operating income per GAAP to non-GAAP total gross operating margin: | | | | |
| Depreciation and amortization in operating costs and expenses | (31,715) | (27,844) | (62,235) | (55,502) |
| Retained lease expense, net in operating costs and expenses | (2,273) | (2,274) | (4,547) | (4,547) |
| Loss (gain) on sale of assets in operating costs and expenses | (17) | 36 | (115) | 32 |
| Selling, general and administrative costs | (7,087) | (10,053) | (16,553) | (21,524) |
| Total non-GAAP gross operating margin | $ 106,143 | $ 106,483 | $ 235,815 | $ 232,921 |

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railroad tankcars for $1 dollar per year. These subleases (the "retained lease expense" in the previous table) are part of the Administrative Services Agreement that we executed with EPCO in connection with our formation in 1998. EPCO holds these items pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. Operating costs and expenses (as shown in the Statements of Consolidated Operations and Comprehensive Income) treat the lease payments being made by EPCO as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded as a general contribution to the Company. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases.

EPCO also assigned to us the purchase options associated with these leases. We notified the lessor of the isomerization unit and related equipment covered under the retained leases of our intent to exercise the purchase options relating to this equipment in 2004. Under the terms of the lease agreements for these assets, we have the option to purchase the equipment at the lesser of fair value or $25.9 million. Should we decide to exercise all of the remaining purchase options associated with the other retained leases (which are also at fair value), an additional $2.3 million would be payable in 2008 and $3.1 million in 2016.

Our gross operating margin amounts by segment were as follows for the periods indicated (dollars in thousands):

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| Gross operating margin by segment: | | | | |
| Pipelines | $ 67,150 | $ 71,969 | $ 150,135 | $ 143,901 |
| Fractionation | 35,888 | 35,871 | 66,148 | 64,918 |
| Processing | 4,379 | 2,685 | 22,444 | 32,641 |
| Octane enhancement | (677) | (3,228) | (1,943) | (6,669) |
| Other | (597) | (814) | (969) | (1,870) |
| Total gross operating margin | $ 106,143 | $ 106,483 | $ 235,815 | $ 232,921 |

The interperiod comparability of gross operating margin for the Pipelines and Octane Enhancement segments shown in the preceding table is impacted by our acquisition of additional ownership interests in certain investees, which required us to change from the equity method of accounting (where we record our share of their individual financial results as equity earnings) to full consolidation of their financial statements with those of our own. The investments affected (and the month in which we began consolidation of their results) are as follows: EPIK, March 2003; OTC, August 2003; BEF, September 2003; Wilprise, October 2003 and Tri-States, April 2004. For equity-method investments, gross operating margin by segment includes the equity earnings we record from the investee (i.e., our share of the investee's net income). When an investee is consolidated, gross operating margin by segment reflects the investee's total gross operating margin, which excludes minority interest expense resulting from third-party ownership interest in the investee.

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

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| **Pipelines, net volumes as shown:** | | | | |
| NGL and petrochemical liquids pipelines (MBPD, net) | 1,331 | 1,295 | 1,381 | 1,303 |
| Natural gas pipelines (BBtus per day, net) | 1,068 | 1,033 | 1,071 | 1,033 |
| Combined energy equivalent (MBPD, net) | 1,612 | 1,566 | 1,663 | 1,575 |
| **Fractionation, net volumes in MBPD:** | | | | |
| NGL fractionation | 237 | 201 | 233 | 218 |
| Propylene fractionation | 60 | 58 | 57 | 59 |
| Isomerization | 78 | 82 | 69 | 81 |
| **Natural gas processing, net volumes as shown:** | | | | |
| Fee-based natural gas processing (MMcf per day, net) | 1,248 | 160 | 805 | 112 |
| Equity NGL production (MBPD, net) | 45 | 39 | 47 | 43 |
| **Octane enhancement, net volumes in MBPD** | 10 | 3 | 7 | 3 |

The following table illustrates selected average quarterly industry index prices for natural gas, crude oil, selected NGL and petrochemical products and indicative gas processing gross spreads since the beginning of 2002:

| | Natural Gas, $/MMBtu | Crude Oil, $/barrel | Ethane, $/gallon | Propane, $/gallon | Normal Butane, $/gallon | Isobutane, $/gallon | Natural Gasoline, $/gallon | Polymer Grade Propylene, $/pound | Refinery Grade Propylene, $/pound | Indicative Gas Processing Gross Spread, $/gallon |
|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (1) | (1) | (1) | (1) | (1) | (1) | (1) | (3) |
| **2002** | | | | | | | | | | |
| 1st Quarter | $2.34 | $21.41 | $0.22 | $0.30 | $0.38 | $0.44 | $0.47 | $0.16 | $0.12 | $0.12 |
| 2nd Quarter | $3.38 | $26.26 | $0.26 | $0.40 | $0.48 | $0.51 | $0.58 | $0.20 | $0.17 | $0.10 |
| 3rd Quarter | $3.16 | $28.30 | $0.26 | $0.42 | $0.52 | $0.58 | $0.61 | $0.21 | $0.16 | $0.14 |
| 4th Quarter | $3.99 | $28.33 | $0.31 | $0.49 | $0.60 | $0.63 | $0.66 | $0.20 | $0.15 | $0.13 |
| Average for Year | $3.22 | $26.08 | $0.26 | $0.40 | $0.50 | $0.54 | $0.58 | $0.20 | $0.15 | $0.12 |
| **2003** | | | | | | | | | | |
| 1st Quarter | $6.58 | $34.12 | $0.43 | $0.65 | $0.76 | $0.80 | $0.85 | $0.24 | $0.21 | $0.05 |
| 2nd Quarter | $5.40 | $29.04 | $0.39 | $0.53 | $0.58 | $0.62 | $0.65 | $0.25 | $0.19 | $0.04 |
| 3rd Quarter | $4.97 | $30.21 | $0.37 | $0.56 | $0.67 | $0.68 | $0.73 | $0.21 | $0.15 | $0.10 |
| 4th Quarter | $4.58 | $31.18 | $0.40 | $0.58 | $0.73 | $0.71 | $0.75 | $0.22 | $0.16 | $0.17 |
| Average for Year | $5.38 | $31.14 | $0.40 | $0.58 | $0.68 | $0.70 | $0.74 | $0.23 | $0.18 | $0.09 |
| **2004** | | | | | | | | | | |
| 1st Quarter | $5.69 | $35.25 | $0.43 | $0.66 | $0.76 | $0.76 | $0.87 | $0.29 | $0.26 | $0.13 |
| 2nd Quarter | $6.00 | $38.34 | $0.45 | $0.65 | $0.79 | $0.79 | $0.92 | $0.32 | $0.26 | $0.12 |
| Average for Year | $5.84 | $36.79 | $0.44 | $0.66 | $0.78 | $0.78 | $0.89 | $0.31 | $0.26 | $0.13 |

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including OPIS and CMAI. Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents an average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.
(2) Crude oil price is representative of an index price for West Texas Intermediate.
(3) The Indicative Gas Processing Gross Spread is a relative measure used by the NGL industry as an indicator of the gross economic benefit derived from extracting NGLs from natural gas production on the U.S. Gulf Coast. Specifically, it is the amount by which the economic value of a composite gallon of NGLs exceeds the value of the equivalent amount of energy of natural gas based on NGL and natural gas prices on the U.S. Gulf Coast. It is assumed that a gallon of NGLs is comprised of 33% ethane, 32% propane, 11% normal butane, 8% isobutane and 16% natural gasoline. The value of a composite gallon of NGLs is determined by multiplying these component percentages by industry index prices listed in the table above. The value of the equivalent amount of energy of natural gas to one gallon of NGLs is 8.9% of the price of a MMBtu of natural gas. The Indicative Gas Processing Gross Spread does not consider the operating and fuel costs incurred by a natural gas processing plant to extract the NGLs nor the transportation and fractionation costs to deliver the NGLs and natural gas to market.

### General business environment

The fundamentals for the NGL industry during the second quarter of 2004 were the strongest that we have seen in the past two years. Ethane demand by the ethylene industry (which is the largest single consumer of ethane and propane) averaged 747 MBPD in the second quarter of 2004 compared to 614 MBPD in the second quarter of 2003. Ethane demand in June 2004 was 765 MBPD compared to 560 MBPD in June 2003.

As a result of global events, we expect that the unusual level of volatility in crude oil, natural gas and NGL prices will continue. The volatility in hydrocarbon prices impacts the prices we charge customers for products and services and those we pay vendors for feedstocks, fuel and other purchases. In addition, this volatility can result in lower of cost or market valuation adjustments to our inventories depending on the carrying values of products at the end of each reporting period.

In addition, higher fuel costs (primarily for natural gas) continue to impact our profitability. This is due to the combination of higher prices for natural gas, natural gas fired electricity and NGLs and the fact that, unlike the contracts under which most of our other facilities operate, our transportation tariffs for the Mid-America and Seminole pipelines do not provide for automatic surcharges to customers for increased fuel costs. During the second quarter of 2004, we took additional steps to minimize our exposure to the volatility of fuel costs by converting NGL-fueled pipeline pump stations to electricity and by entering into a five-year fixed price contract to purchase power from a coal-fired power plant in Texas. We are also evaluating a cost of service filing with the FERC for the recovery of the increased fuel costs on the Mid-America and Seminole pipelines through an increase in our transportation tariffs.

**Three months ended June 30, 2004 compared to three months ended June 30, 2003**

Revenues for the second quarter of 2004 increased $502.7 million over those recorded during the same period in 2003. Processing segment revenues increased $315.6 million quarter-to-quarter primarily due to higher sales volumes and NGL prices. On a weighted-average basis, NGL prices increased from 52 CPG during the second quarter of 2003 to 66 CPG during the second quarter of 2004. Fractionation segment revenues increased $103.1 million quarter-to-quarter primarily due to a $131.4 million increase in propylene fractionation revenues resulting from higher sales volumes and polymer and refinery-grade propylene prices. In addition, the consolidation of BEF added $70.8 million in revenues. We began consolidating BEF's results with those of our own after purchasing an additional 33.3% interest in BEF on September 30, 2003.

Operating costs and expenses increased $519.3 million quarter-to-quarter primarily due to a $415.2 million increase in cost of sales related to NGL and propylene fractionation marketing activities. The increase in cost of sales was caused by higher purchase volumes and prices. In addition, the consolidation of BEF added $41.8 million in operating costs and expenses. Lastly, depreciation and amortization in operating costs and expenses increased $3.9 million quarter-to-quarter as a result of capital expenditures and business acquisitions completed since June 30, 2003.

Selling, general and administrative costs decreased $3 million quarter-to-quarter generally due to the timing of such expenditures and cost reduction programs. Earnings from equity method unconsolidated affiliates increased $12.3 million quarter-to-quarter primarily due to $10.7 million recorded from GulfTerra GP in the second quarter of 2004. We acquired a 50% membership interest in GulfTerra GP from El Paso in December 2003. Overall, the impact of increased operating expenses for the second quarter of 2004 lowered operating income $1.2 million quarter-to-quarter.

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

*Pipelines.* Gross operating margin from our Pipelines segment was $67.2 million for the second quarter of 2004 compared to $72 million for the second quarter of 2003. On an energy-equivalent basis, net pipeline throughput was 1,612 MBPD for the second quarter of 2004 versus 1,566 MBPD for the second quarter of 2003. Gross operating margin for the second quarter of 2004 includes $10.7 million of equity earnings from GulfTerra GP.

NGL and petrochemical volumes increased to 1,331 MBPD during the second quarter of 2004 from 1,295 MBPD during the second quarter of 2003. Gross operating margin from our Mid-America and Seminole pipelines for the second quarter of 2004 was $31.1 million compared to $39.9 million for the second quarter of 2003. Net NGL volumes transported by the two pipelines increased by 43 MBPD quarter-to-quarter. The $8.8 million decrease in gross operating margin from the second quarter of last year is primarily due to a one-time $3.8 million reduction in operating expense related to acquisition costs in 2003 that did not recur in 2004 and a $3.6 million increase in repair, maintenance and fuel expenses, including $1.8 million that was attributable to our pipeline integrity inspection program. The increase in expenses from the prior year more than offset the increase in gross operating margin associated with the higher transportation volumes. Beginning July 1, 2004, the tariffs on the Mid-America and Seminole pipeline will increase revenue by approximately $7.2 million on an annual basis as the result of the annual adjustment for the increase in the Producer Price Index ("PPI").

As a result of increased natural gas sales margins, gross operating margin from Acadian Gas increased $1.4 million quarter-to-quarter. Natural gas throughput on this system increased 29 BBtu/d quarter-to-quarter. Equity earnings from our Gulf of Mexico natural gas pipeline investments decreased $1.4 million quarter-to-quarter primarily due to the underperformance of the Brutus and Hickory fields and natural depletion of production fields served by our pipeline systems, which was partially offset by new natural gas production from other fields. Overall, natural gas pipeline throughput volumes were 1,068 BBtu/d during the second quarter of 2004 versus 1,033 BBtu/d during the second quarter of 2003.

Our NGL import facility posted a $2.2 million decrease in gross operating margin quarter-to-quarter primarily due to a 63 MBPD decrease in import volumes. Greater worldwide demand for NGLs during the second quarter of 2004 resulted in competition for NGLs and the diversion of volumes to other international markets that normally would have been delivered to the U.S. Gulf Coast. Gross operating margin from our HSC pipeline decreased $1.8 million quarter-to-quarter due to lower volumes originating from our NGL import facility.

Gross operating margin from the Lou-Tex NGL pipeline decreased by $2.8 million quarter-to-quarter due to a 12 MBPD decrease in volume. This decrease in margin and volume was due to our election to maximize total gross operating margin by diverting mixed NGLs and refinery-grade propylene to our other facilities.

Total pipeline integrity inspection and testing expense for the second quarter of 2004 was approximately $3.1 million compared to $0.1 million in the second quarter of 2003. In addition, approximately $1.2 million of major pipeline integrity repair costs were capitalized during the second quarter of 2004 compared to $0.7 million in the second quarter of last year.

*Fractionation.* Gross operating margin from our Fractionation segment was $35.9 million for the second quarters of both 2004 and 2003. Gross operating margin from NGL fractionation decreased $3.4 million quarter-to-quarter. NGL fractionation volumes were 237 MBPD during the second quarter of 2004 compared to 201 MBPD during the second quarter of 2003. Gross operating margin from our Mont Belvieu NGL fractionator decreased $8.7 million quarter-to-quarter primarily due to $6.8 million in net gains associated with the measurement of mixed NGLs in storage pending fractionation we recorded in the second quarter of 2003, which did not recur in the second quarter of 2004. Gross operating margin from our Norco facility increased $5 million quarter-to-quarter primarily due to (i) a net 23 MBPD increase in volumes resulting from an expansion of the facility completed during the fourth quarter of 2003 and (ii) higher prices for NGL volumes sold by Norco that it takes ownership of as a result of percent-of-liquids based fractionation agreements.

Gross operating margin from propylene fractionation increased $4.2 million quarter-to-quarter primarily due to an increase in petrochemical marketing sales volumes. Propylene fractionation volumes were 60 MBPD during the second quarter of 2004 compared to 58 MBPD during the second quarter of 2003. Gross operating margin from isomerization decreased $0.5 million quarter-to-quarter primarily due to a lower volumes and tolling revenues, which were partially offset by higher by-product revenues. Isomerization volumes were 78 MBPD during the second quarter of 2004 compared to 82 MBPD during the second quarter of 2003.

*Processing.* Gross operating margin from our Processing segment was $4.4 million for the second quarter of 2004 compared to $2.7 million for the second quarter of 2003. Gross operating margin from our gas processing plants increased $9.2 million quarter-to-quarter. Equity NGL production was 45 MBPD for the second quarter of 2004 compared to 39 MBPD for the second quarter of 2003. Natural gas processing volumes under contracts with fee-based components increased to 1,248 MMcf/d in the second quarter of 2004 from 160 MMcf/d in the second quarter of 2003 reflecting the amendments to our major processing agreements. For additional information regarding the restructuring of our natural gas processing mix, please read "*– Recent Developments – Amendments to natural gas processing agreements.*"

Gross operating margin from NGL marketing activities was a loss of $5.8 million for the second quarter of 2004 compared to a profit of $1.7 million in the second quarter of 2003. The second quarter of 2004 includes a loss of $13.4 million associated with the ineffectiveness of a practice that we used to manage our NGL production and inventory on a seasonal basis. Historically, there has been a seasonal price decrease for NGLs from the first quarter to the second quarter of a given year, due in part to greater demand in the winter months for propane for space heating and for butanes in the production of motor gasoline. Part of our inventory practice at the beginning of the second quarter of 2004 was to sell NGLs at prices that were greater than our expected production or purchased volume costs in the second quarter of 2004 to take advantage of expected seasonal price differences. In prior years, this practice had been generally profitable. Unfortunately, this practice did not work for us in the second quarter of 2004 because of the significant increase and volatility in crude oil, natural gas and NGL prices partly due to global events. We expect that the unusual level of volatility in hydrocarbon prices will continue in the near term. As a result, we will limit the amount of NGLs that we will sell under this practice to about five days of our equity NGL production, or approximately 250,000 barrels.

When current market prices are below the carrying cost of our various inventories, we are required to record a lower of cost or market adjustment to reduce the carrying costs to their respective market values. We recorded $1.8 million of lower of cost or market adjustments for the second quarter of 2004 compared to $3.4 million of such adjustments for the second quarter of 2003. Beginning with the third quarter of 2004, we will reclassify approximately 775,000 barrels of linefill that we own as a shipper on certain NGL pipelines from inventory to property on our consolidated balance sheet. This change is due to business reasons that require us to maintain volumes as permanent linefill and is consistent with our classification of linefill for other pipelines. Such volumes will be subject to periodic impairment testing under SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets.*"

*Octane enhancement.* Gross operating margin from the BEF facility was a loss of $0.7 million for the second quarter of 2004 versus a loss of $3.2 million for the second quarter of 2003. Comparability of the two gross operating margin amounts is affected by changes in our ownership interest in the facility. Gross operating margin for the second quarter of 2004 is a consolidated amount reflecting the facility's overall performance; whereas the amount recorded for the second quarter of 2003 reflects only our 33.3% share of BEF's losses that we recorded in equity earnings from unconsolidated affiliates. Upon our acquisition of an additional 33.3% partnership interest in BEF on September 30, 2003, it became a majority-owned consolidated subsidiary of ours. Prior to this date, BEF was accounted for as an equity method unconsolidated affiliate. Since we began consolidating BEF's results with those of our own, Sun's 33.3% share of BEF's earnings is reflected as a component of minority interest expense.

For comparability purposes, the following information is provided on a 100% basis for BEF (i.e., at an entity level before consolidation with our own results). Revenues improved $29.8 million quarter-to-quarter primarily due to a 5 MBPD increase in MTBE production and higher MTBE prices. Operating costs and expenses increased $23.7 million, which was generally due to an increase in feedstock and fuel costs partially offset by lower repair and maintenance charges. On January 1, 2004, BEF changed the method it uses to account for planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method. As a result, turnaround-related repair and maintenance expenses decreased $1.2 million quarter-to-quarter. For additional information regarding this change in accounting principle please read " *– Other Items – Cumulative effect of change in accounting principle recorded in first quarter of 2004.*"

**Six months ended June 30, 2004 compared to six months ended June 30, 2003**

Revenues for the first six months of 2004 increased $726 million over those recorded during the same period in 2003. Processing segment revenues increased $491.9 million period-to-period primarily due to higher sales volumes and NGL prices. On a weighted-average basis, NGL prices increased from 57 CPG during the first six months of 2003 to 65 CPG during the same period in 2004. Fractionation segment revenues increased $122.6 million period-to-period due to a $155.7 million increase in propylene fractionation revenues primarily due to higher sales volumes and polymer and refinery-grade propylene prices. In addition, the consolidation of BEF added $98.1 million in revenues.

Operating costs and expenses increased $754.1 million period-to-period primarily due to a $619.6 million increase in cost of sales related to NGL and propylene fractionation marketing activities. The increase in cost of sales was caused by higher purchase volumes and prices. In addition, the consolidation of BEF added $57.1 million in operating costs and expenses. Lastly, depreciation and amortization in operating costs and expenses increased $6.7 million period-to-period as a result of capital expenditures and business acquisitions completed since June 30, 2003.

Selling, general and administrative costs decreased $5 million period-to-period generally due to the timing of expenditures, cost reduction programs and the first quarter of 2003 including a $2 million payment to Williams for transition services related to our acquisition of the Mid-America and Seminole pipelines. Earnings from equity method unconsolidated affiliates increased $24.1 million period-to-period primarily due to $21.3 million recorded from GulfTerra GP. As a result of the aforementioned results, operating income increased $1 million period-to-period.

The $7.0 million benefit recorded as a cumulative effect of change in accounting principle is due to our BEF subsidiary changing its method of accounting for planned major maintenance activities. For additional information regarding this non-cash item, please read " – *Other Items – Cumulative effect of change in accounting principle recorded in first quarter of 2004.*"

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

*Pipelines.* Gross operating margin from our Pipelines segment was $150.1 million for the first six months of 2004 compared to $143.9 million for the same period in 2003. On an energy-equivalent basis, net pipeline throughput was 1,663 MBPD for the 2004 period versus 1,575 MBPD for the 2003 period. Gross operating margin for the first six months of 2004 includes $21.3 million of equity earnings from GulfTerra GP.

NGL and petrochemical volumes increased to 1,381 MBPD during the first six months of 2004 from 1,303 MBPD during the same period in 2003. Gross operating margin from our Mid-America and Seminole pipelines for the 2004 period was $74.1 million compared to $87.4 million for the 2003 period. Net NGL volumes transported by the two pipelines increased by 29 MBPD period-to-period. The $13.3 million decrease in gross operating margin from the first six months of 2003 is primarily due to a $4.1 million increase in repair, maintenance and fuel expenses, including $2.2 million that was attributable to our pipeline integrity inspection program; a one-time $3.8 million reduction in operating expense in 2003 that did not recur in 2004 and a $2.2 million increase in fees charged to Seminole for the use of a third-party pipeline to transport volumes during certain periods in 2004 to avoid high fuel costs.

Gross operating margin from Acadian Gas increased $2.9 million period-to-period as a result of increased transportation volumes and natural gas sales margins. Natural gas throughput on this system increased 57 BBtu/d period-to-period. Equity earnings from our Gulf of Mexico natural gas pipeline investments decreased $1.9 million period-to-period primarily due to the underperformance of the Brutus and Hickory fields and natural depletion of production fields served by our pipeline systems, which was partially offset by new natural gas production from other fields. Overall, natural gas pipeline throughput volumes were 1,071 BBtu/d during the first six months of 2004 compared to 1,033 BBtu/d during the first six months of 2003.

Gross operating margin from our HSC pipeline decreased $1.6 million period-to-period primarily due to a 38 MBPD decrease in throughput volumes. Gross operating margin from our Lou-Tex NGL pipeline decreased $5.8 million period-to-period as a result of a 16 MBPD decrease in volumes attributable to reduced NGL shipments from Louisiana to Texas. The decrease in margin and volume for the Lou-Tex NGL pipeline was due to our election to maximize total gross operating margin by diverting mixed NGLs and refinery-grade propylene to our other facilities.

Total pipeline integrity inspection and testing expense for the first six months of 2004 was approximately $4.3 million compared to $0.2 million for the same period in 2003. In addition, approximately $2.0 million of major pipeline integrity repair costs were capitalized during the first six months of 2004 compared to $1.0 million during the same period in 2003.

*Fractionation.* Gross operating margin from our Fractionation segment was $66.1 million for the first six months of 2004 compared to $64.9 million for the first six months of 2003. Gross operating margin from NGL fractionation decreased $2.6 million period-to-period. NGL fractionation volumes were 233 MBPD during the 2004 period versus 218 MBPD during the 2003 period. Gross operating margin from our Mont Belvieu NGL fractionator decreased $10.1 million period-to-period primarily due to $5.1 million in net gains we recorded during the first six months of 2003 associated with the measurement of mixed NGLs in storage pending fractionation compared to $3.2 million in net losses we recorded during the same period in 2004 from such measurement activities, which resulted in an $8.3 million negative variance period-to-period. Gross operating margin from our Norco facility increased $7.2 million period-to-period primarily due to (i) a 22 MBPD increase in volumes due to an expansion of the facility completed during the fourth quarter of 2004 and (ii) higher prices for NGL volumes sold by Norco that it takes ownership of as a result of percent-of-liquids based fractionation agreements.

Gross operating margin from propylene fractionation increased $9.1 million period-to-period primarily due to an increase in petrochemical marketing sales volumes and margins. Propylene fractionation volumes were 57 MBPD during the first six months of 2004 compared to 59 MBPD during the first six months of 2003. Gross operating margin from isomerization decreased $3.1million period-to-period primarily due to lower processing volumes. Isomerization volumes were 69 MBPD during the first six months of 2004 compared to 81 MBPD during the first six months of 2003.

*Processing.* Gross operating margin from our Processing segment was $22.4 million for the first six months of 2004 compared to $32.6 million for the same period in 2003. Gross operating margin from our gas processing plants increased $20.2 million period-to-period. Equity NGL production was 47 MBPD during the 2004 period compared to 43 MBPD during the 2003 period. Natural gas processing volumes under contracts with fee-based components increased to 805 MMcf/d during the first six months of 2004 from 112 MMcf/d during the first six months of 2003 reflecting amendments to our major processing agreements.

We recently completed a program to convert essentially all of our traditional keepwhole contracts to other types of processing arrangements where the producer assumes all or most of the direct commodity price risk between NGLs and natural gas. These new arrangements include simple fee-based contracts, hybrid fee-based contracts with margin-sharing provisions and percent-of-liquids agreements. For additional information regarding the restructuring of our natural gas processing mix, please read "*– Recent Developments – Amendments to natural gas processing agreements.*"

Gross operating margin from NGL marketing activities was a loss of $3.1 million for the first six months of 2004 compared to income of $27.4 million for the first six months of 2003. NGL marketing results for the 2003 period benefited from unusually strong demand for propane and normal butane. Also, as noted in the Processing segment's quarter-to-quarter highlights on page 44, the second quarter of 2004 includes a loss of $13.4 million associated with the ineffectiveness of a practice that was used to manage our NGL production and inventory on a seasonal basis. Commodity hedging results for both periods were insignificant. Lastly, we recorded $5.1 million of lower of cost or market adjustments during the first six months of 2004 compared to $12.2 million for the same period in 2003.

*Octane enhancement.* Gross operating margin from the BEF facility was a loss of $1.9 million for the first six months of 2004 compared to a loss of $6.7 million for the same period in 2003. As noted on page 45 in our explanation of BEF's quarter-to-quarter variances, comparability of these gross operating margin amounts is impacted by changes in our ownership interest in BEF. The 2004 amount represents an overall consolidated total (with Sun's 33.3% ownership share deducted in minority interest expense); whereas the 2003 amount represents our original 33.3% partnership interest in BEF's earnings. We acquired an additional 33.3% partnership interest in BEF on September 30, 2003, which resulted in the consolidation of BEF's financial results with those of our own from that date forward.

For comparability purposes, the following information is provided on a 100% basis for BEF (i.e., at an entity level before consolidation with our own results). Revenues increased $8.3 million period-to-period primarily due to $12.1 million in isobutylene sales. MTBE production rates were 11 MBPD during the first six months of 2004 compared to 10 MBPD during the same period in 2003. Operating costs and expenses decreased $3.8 million period-to-period generally due to BEF's change in the manner in which it accounts for major maintenance activities. On January 1, 2004, BEF changed the method it uses to account for planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method. As a result, turnaround-related repair and maintenance expenses decreased $3.4 million period-to-period. For additional information regarding this change in accounting principle please read " *– Other Items – Cumulative effect of change in accounting principle recorded in first quarter of 2004.*"

## OUR LIQUIDITY AND CAPITAL RESOURCES

### General

Our primary cash requirements, in addition to normal operating expenses and debt service, are for capital expenditures, business acquisitions and distributions to our partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows. Capital expenditures for long-term needs resulting from internal growth projects and business acquisitions are expected to be funded by a variety of sources including (either separately or in combination) cash flows from operating activities, borrowings under commercial bank credit facilities, the issuance of additional partnership equity and public or private placement debt. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

As noted above, certain of our liquidity and capital resource requirements are fulfilled by borrowings made under debt agreements and/or proceeds from the issuance of additional partnership equity. At June 30, 2004, we had approximately $1.8 billion in principal outstanding under various debt agreements. On that date, total borrowing capacity under our revolving commercial bank credit facilities was $500 million of which $425.6 million was unused. For additional information regarding our debt, please read " – *Our debt obligations.*"

We have on file with the SEC a $1.5 billion universal shelf registration statement covering the issuance of an unallocated amount of partnership equity or public debt obligations (separately or in combination). In June 2003 and May 2004, we sold 11,960,000 and 17,250,000 common units, respectively, under this registration statement. In May 2004, we sold 17,250,000 common units under this registration statement from which we received net proceeds of $353.1 million, including our General Partner's proportionate net capital contribution of $7.1 million. On August 9, 2004, we sold 15,000,000 common units under this registration statement from which we received net proceeds of $296.9 million, including our General Partner's proportionate net capital contribution of $5.9 million. After deducting for the June 2003, May 2004 and August 2004 equity offerings, the amount available for future offerings under this shelf registration statement is $0.6 million.

In April 2004, we filed a new registration statement with the SEC covering an additional 10,000,000 common units issuable under our Distribution Reinvestment Plan (or "DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional common units. The new registration statement increased the number of common units issuable under the DRIP from 5,000,000 to 15,000,000. We expect to use the cash generated from this reinvestment program primarily for general partnership purposes. Since its inception in August 2003 through June 30, 2004, we have issued 5,621,591 common units under this program generating net proceeds (including our General Partner's proportionate net capital contributions) of approximately $119 million. This amount includes 1,053,510 common units issued under this program in February 2004 and 1,729,904 common units issued in May 2004, which together generated proceeds of approximately $58 million.

To support our growth objectives and financial flexibility, EPCO has reinvested approximately $105 million of its cash distributions since August 2003 through the DRIP (including $50 million in 2004). In addition, EPCO has announced that it expects to reinvest an additional $60 million of its anticipated quarterly distributions through the first quarter of 2005.

If deemed necessary, we believe that additional financing arrangements can be obtained on reasonable terms. Furthermore, we believe that maintenance of an investment grade credit rating combined with continued ready access to debt and equity capital at reasonable rates and sufficient trade credit to operate our businesses efficiently provide a solid foundation to meet our long and short-term liquidity and capital resource requirements.

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

| | For the Six Months Ended June 30, | |
|---|---|---|
| | 2004 | 2003 |
| **Net income** | $ 91,616 | $ 73,610 |
| Adjustments to reconcile net income to cash flow from operating activities before changes in operating accounts: | | |
| Depreciation and amortization in operating costs and expenses | 62,390 | 55,551 |
| Amortization in interest expense | 1,843 | 11,915 |
| Distributions received from unconsolidated affiliates: (1) | | |
| GulfTerra GP (2) | 21,473 | |
| Other equity method investments (3) | 12,248 | 20,865 |
| Equity in income of unconsolidated affiliates: (1) | | |
| GulfTerra GP (2) | (21,266) | |
| Other equity method investments (4) | (4,241) | (1,393) |
| Increase in restricted cash (5) | (9,286) | (12,781) |
| Cumulative effect of change in accounting principle | (7,013) | |
| Other | 11,275 | 13,552 |
| **Cash flow from operating activities before changes in operating accounts** | 159,039 | 161,319 |
| Net effect of changes in operating accounts | (51,181) | (41,067) |
| **Cash provided by operating activities** | $ 107,858 | $ 120,252 |

(1) Distributions from unconsolidated affiliates and equity in income of unconsolidated affiliates have been presented in a manner to aid in comparability between periods.
(2) We acquired our 50% non-voting interest in GulfTerra GP in December 2003. We account for our investment in GulfTerra GP using the equity-method.
(3) The 2003 period includes $6.6 million of cash distributions attributable to unconsolidated affiliates which became consolidated subsidiaries in 2003 and 2004.
(4) The 2003 period includes $3.6 million of losses attributable to unconsolidated affiliates which became consolidated subsidiaries in 2003 and 2004.
(5) Restricted cash consists of amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for the physical purchase of natural gas made on the NYMEX exchange.

Operating activities cash flows primarily reflect net income adjusted for depreciation, amortization and similar non-cash amounts; equity earnings and cash distributions from unconsolidated affiliates and changes in operating accounts. The net effect of changes in operating accounts is generally the result of timing of sales and purchases near the end of each period. Cash flow from operations is primarily based on earnings from our business activities. As a result, these cash flows are exposed to certain risks. The products that we process, sell or transport are principally used as feedstocks in petrochemical manufacturing, in the production of motor gasoline and as fuel for residential, agricultural and commercial heating. Reduced demand for our products or services by industrial customers, whether because of general economic conditions, reduced demand for the end products made with our products or increased competition from petroleum-based products due to pricing differences or other reasons could have a negative impact on our earnings and thus the availability of cash from operating activities. Other risks include fluctuations in NGL and energy prices, competitive practices in the midstream energy industry and the impact of operational and systems risks. For additional information regarding risk factors pertinent to our business, please read "*Cautionary Statement Regarding Forward-Looking Information and Risk Factors*" on page 35 of this quarterly report.

**Six months ended June 30, 2004 compared to six months ended June 30, 2003**

*Operating activities.* For the six months ended June 30, 2004 and 2003, cash provided by operating activities was $107.9 million and $120.3 million, respectively. As shown in the preceding table, cash flow before the net effect of changes in operating accounts was an inflow of $159 million for the 2004 period versus $161.3 million for the 2003 period. We believe that cash flow from operating activities before the net effect of changes in operating accounts is an important measure of our ability to generate core cash flows from our assets and other investments.

Distributions received from our equity-method unconsolidated affiliates were $33.7 million for the 2004 period compared to $20.9 million for the 2003 period. The $12.8 million increase in this element of our cash flows is primarily due to cash distributions from GulfTerra GP offset by the effects of consolidating former equity method investments as a result of acquisitions. In addition, the 2003 period includes a special distribution of approximately $5 million from our Starfish unconsolidated affiliate in connection with the settlement of a rate case. The period-to-period fluctuation in the restricted cash balance is primarily due to the timing of physical purchases of natural gas on the NYMEX exchange.

The net effect of changes in operating accounts is generally the result of timing of cash receipts from sales and cash payments for inventory and other purchases near the end of the period. Overall, the net effect of changes in operating accounts was an outflow of $51.2 million and $41.2 million for the six months ended June 30, 2004 and 2003, respectively. Our operating asset-related expenditures were a $128.4 million outflow during the 2004 period compared to a $4.2 million inflow during the 2003 period. The change in operating asset cash flows is primarily due to fluctuations in our inventory balances. Our liability-related cash flows were a $77.2 inflow during the 2004 period versus a $45.2 million outflow during the 2003 period. The primary reason for the increase in these operating accounts was an increase in gas payables related to inventory.

*Investing activities.* For the six months ended June 30, 2004 and 2003, we used $74.7 million and $112.1 million, respectively, for investing activities. Capital expenditures were $27.9 million for the 2004 period versus $54.5 million for the 2003 period. For additional information regarding our capital expenditures, please read "– *Capital spending*" on page 53. During 2004, we used $45.1 million to purchase additional ownership interests in Tri-States and Seminole. The 2003 period includes our purchase of the Port Neches Pipeline and the remaining 50% ownership interest in EPIK. Our investments in and advances to unconsolidated affiliates for the first six months of 2003 included amounts we contributed to our Gulf of Mexico natural gas pipeline investments for their expansion capital projects.

*Financing activities.* We used $24.2 million and $2.9 million in financing activities during the first six months of 2004 and 2003, respectively. For the first six months of 2004, our net repayments under debt agreements were $362 million compared to $371.8 million for the same period in 2003. Our repayments of debt during the first six months of 2004 primarily reflect the use of proceeds from our May 2004 equity offering to repay the $225 million Interim Term Loan and to temporarily reduce amounts outstanding under our revolving credit facilities. In addition, we also used the $104.5 million in proceeds from our April 2004 settlement of certain interest rate hedging financial instruments to temporarily reduce amounts outstanding under our revolving credit facilities.

The 2003 period reflects our issuance of Senior Notes C ($350 million in principal amount) and Senior Notes D ($500 million in principal amount) and the final repayment of $1.0 billion that was outstanding under the bridge loan financing we used to purchase interest in the Mid-America and Seminole pipelines. Repayments of debt during the first six months of 2003 also reflects the use of proceeds from our January 2003 and June 2003 equity offerings.

Cash distributions to partners increased from $143 million during the first six months of 2003 to $181 million during the same period in 2004. The increase in cash distributions is primarily due to an increase in both the declared quarterly distribution rates and the number of units eligible for distributions. We expect that future cash distributions to partners will increase as a result of our periodic issuance of common units under the DRIP and other equity offerings.

Net proceeds from the sale of common units were $411.6 million during the first six months of 2004 compared to $514.3 million for the same period in 2003. Both amounts include our General Partner's net proportionate capital contributions. In May 2004, we sold 17,250,000 common units to the public (including the underwriters' overallotment amount of 2,250,000 common units) at an offering price of $21.00 per unit. Net proceeds from this offering, including our General Partner's proportionate net capital contribution of $7.1 million, were $353.1 million after deducting applicable underwriting discounts, commissions and offering expenses of $16.3 million. The 2004 period also $58.4 million in proceeds from the sale of 2,811,208 common units in connection with our DRIP, the proceeds of which were primarily used for working capital purposes. Proceeds from the issuance of common units during the first six months of 2003 were $514.3 million and reflect the sale of 14,662,500 and 11,960,000 common units in our January 2003 and June 2003 equity offerings, respectively.

Although not reflected in financing activity cash flow totals for the first six months of 2004, we sold 15,000,000 common units to the public on August 9, 2004 at an offering price of $20.20 per unit. Net proceeds from this offering, including our General Partner's proportionate net capital contribution of $5.9 million, were approximately $296.9 million after deducting applicable underwriting discounts, commissions and offering expenses of $12.3 million. The net proceeds from this offering, including our General Partner's proportionate net capital contribution will be used to fund a portion of the purchase price of Steps Two and Three of the GulfTerra merger transactions and to temporarily reduce borrowings under our Multi-Year Revolving Credit Facility, or, if the proposed merger with GulfTerra does not close, for working capital purposes or for future acquisitions.

**Our debt obligations**

Our debt consisted of the following at the dates indicated:

| | June 30, 2004 | December 31, 2003 |
|---|---|---|
| Borrowings under: | | |
| Interim Term Loan, variable rate, repaid in May 2004 (1) | | $ 225,000 |
| 364-Day Revolving Credit Facility, variable rate, due October 2004, $230 million borrowing capacity | | 70,000 |
| Multi-Year Revolving Credit Facility, variable rate, due November 2005, $270 million borrowing capacity (2) | $ 48,000 | 115,000 |
| Senior Notes A, 8.25% fixed rate, due March 2005 | 350,000 | 350,000 |
| Seminole Notes, 6.67% fixed rate, $15 million due in December 2004 and 2005 (3) | 30,000 | 30,000 |
| MBFC Loan, 8.70% fixed rate, due March 2010 | 54,000 | 54,000 |
| Senior Notes B, 7.50% fixed rate, due February 2011 | 450,000 | 450,000 |
| Senior Notes C, 6.375% fixed rate, due February 2013 | 350,000 | 350,000 |
| Senior Notes D, 6.875% fixed rate, due March 2033 | 500,000 | 500,000 |
| Total principal amount | 1,782,000 | 2,144,000 |
| Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt | 1,410 | 1,531 |
| Unamortized balance of decrease in fair value related to hedging a portion of fixed-rate debt | (10,146) | |
| Less unamortized discount on Senior Notes A, B, and D | (5,920) | (5,983) |
| Subtotal long-term debt | 1,767,344 | 2,139,548 |
| Less current maturities of debt (4) | (364,974) | (240,000) |
| Long-term debt (4) | $ 1,402,370 | $ 1,899,548 |
| | | |
| Standby letters of credit outstanding, $75 million of credit capacity available under our Multi-Year Revolving Credit Facility | $ 26,400 | $ 1,300 |

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

(2) This revolving credit facility has $270 million of total borrowing capacity, which is reduced by the amount of standby letters of credit outstanding.

(3) Solely as it relates to the assets of our subsidiary, Seminole Pipeline Company, our $1.8 billion in senior indebtedness at June 30, 2004 is structurally subordinated and ranks junior in right of payment to the $30 million of indebtedness of Seminole Pipeline Company.

(4) In accordance with SFAS No. 6, "Classification of Short-Term Obligations Expected to Be Refinanced," long-term and current maturities of debt at December 31, 2003 reflected our option and ability to convert any revolving credit balance outstanding at maturity under the 364-Day Revolving Credit Facility to a one-year term loan (due October 2005) in accordance with the terms of the agreement.

*Scheduled future maturities of long-term debt.* We have long and short-term payment obligations under credit agreements such as our Senior Notes and revolving credit facilities. Scheduled future maturities of debt obligations existing at June 30, 2004 were: $15 million due in 2004; $413 million due in 2005; $54 million due in 2010; $450 million due in 2011; $350 million due in 2013; and $500 million due in 2033. On May 5, 2004, we used $353.1 million in net proceeds from our May 2004 equity offering to repay the $225 million Interim Term Loan and approximately $128.1 million to temporarily reduce debt outstanding under our revolving credit facilities.

*Parent-Subsidiary guarantor relationships.* We act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Seminole Notes. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own an effective 88.4% of its capital stock).

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

*Information regarding variable interest rates paid*

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

| | **Range of interest rates paid** | **Weighted-average interest rate paid** |
|---|---|---|
| 364-Day Revolving Credit Facility | 1.72% to 4.00% | 1.79% |
| Multi-Year Revolving Credit Facility | 1.67% to 4.25% | 1.71% |
| Interim Term Loan | 1.72% to 1.78% | 1.73% |

**Credit ratings**

In May 2004, both Moody's Investors Service and Standard & Poor's Rating Services lowered their corporate credit ratings on Enterprise. Moody's lowered its rating on Enterprise from Baa2 to Baa3 (investment grade) and maintained a negative outlook. Standard & Poor's lowered its rating on Enterprise from BBB- with a negative outlook to BB+ (non-investment grade) with a stable outlook. After completion of the proposed merger with GulfTerra, these credit rating agencies may continue to view our current debt, and therefore the debt of the post-merger combined company, negatively.

If one or both of these credit rating agencies were to further downgrade our credit standing, we could experience an increase in our borrowing costs, difficulty accessing capital markets or a reduction in the market price of our common units. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures, acquisitions and to refinance indebtedness.

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

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

**Our material contractual obligations**

With regards to our material contractual obligations, there have been no significant changes outside of the ordinary course of business since December 31, 2003 with the exception that we used $104.5 million in proceeds from the April 2004 settlement of certain interest rate hedging financial instruments and $353.1 million in net proceeds from our May 2004 equity offering to reduce debt outstanding. The following table summarizes the maturities of our long-term debt, including current portions, at June 30, 2004:

| | | Payment or Settlement due by Period | | | |
|---|---|---|---|---|---|
| **Contractual Obligations** | **Total** | **Less than 1 year** | **1-3 years** | **3-5 years** | **More than 5 years** |
| Time period during which obligation is due | | (Remainder of 2004) | (1/1/2005 – 12/31/2006) | (1/1/2007 – 12/31/2008) | Beyond 1/1/2008 |
| Long-term debt, including current maturities (1) | $ 1,782,000 | $ 15,000 | $ 413,000 | | $ 1,354,000 |

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

**Capital spending**

For the six months ended June 30, 2004 and 2003, we spent $27.9 million and $54.5 million on capital projects recorded as property, plant and equipment. The following table summarizes our capital expenditures for the periods indicated:

| | For the Six Months Ended June 30, 2004 | For the Six Months Ended June 30, 2003 |
|---|---|---|
| Capital expenditures by segment: | | |
| Pipelines | $ 14.0 | $ 22.8 |
| Fractionation | 5.6 | 14.9 |
| Processing | 3.8 | 21.2 |
| Octane Enhancement | 2.6 | |
| Other | 8.1 | 4.1 |
| Reclassifications (1) | (6.2) | (8.5) |
| Total capital expenditures | $ 27.9 | $ 54.5 |
| | | |
| Sustaining capital expenditures (2) | $ 9.9 | $ 5.5 |
| Expansion capital expenditures (2) | 18.0 | 49.0 |
| Total capital expenditures | $ 27.9 | $ 54.5 |

(1) Represents the reversal of prior year-end construction-in-progress accruals, which is offset by the recording of actual amounts during the current year in the capital expenditure by segment totals.

(2) For internal reporting purposes, we generally classify improvements and major renewals of existing assets as sustaining capital expenditures and all other capital spending (on existing and new assets) as expansion capital expenditures.

For the remainder of 2004, we expect our share of capital expenditures to approximate $52.2 million, of which $28.5 million is forecast to be spent on Pipelines segment projects and approximately $4.8 million on modifications to the BEF facility to produce iso-octane. We expect to invest approximately $6.0 million in the capital projects of our unconsolidated affiliates during the remainder of 2004, of which $5.3 million is attributable to projects of our Gulf of Mexico natural gas pipeline investments. At June 30, 2004, we had approximately $4.4 million in outstanding purchase commitments related to capital projects.

*Retained Leases*

In 1998, EPCO assigned to us the purchase options associated with certain operating leases that it contributed to us at our formation (the "retained leases"). We have notified the lessors of an isomerization unit and related equipment covered under the retained leases of our intent to exercise the purchase options relating to this equipment in 2004. Under the terms of the lease agreements for these assets, we have the option to purchase the equipment at the lesser of fair value or $25.9 million. Should we decide to exercise all of the remaining purchase options associated with the other retained leases (which are also at fair value), an additional $2.3 million would be payable in 2008 and $3.1 million in 2016.

*Pipeline Integrity Costs*

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

During the first six months of 2004, we spent approximately $6.2 million to comply with these new regulations, of which $4.3 million was recorded as an operating expense of our Pipelines segment. Based on information currently available, our cash outlays for this program are estimated at $11.2 million for the remainder of 2004 and in the range of $8.5 million to $18.7 million for each of the years 2005 through 2008. At present, we expect that the majority of our pipeline integrity management program costs will be recorded as operating expenses within our Pipelines segment. The remainder will be classified as sustaining capital expenditures.

## RECENT ACCOUNTING DEVELOPMENTS

*FIN 46, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51."* This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 (as amended by FIN 46R) in 2003 has had no material effect on our consolidated financial statements.

Due to the complexity of FIN 46 (as amended by FIN 46R and interpreted), the FASB is continuing to provide guidance regarding implementation issues. Since this guidance is still continuing, our conclusions regarding the application of this guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of FIN 46.

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

Currently, we account for our 13.1% investment in Venice Energy Services Company, LLC ("VESCO") using the cost method. As a result, we have recognized dividend income from VESCO to the extent that we have received cash distributions from them. In accordance with the new accounting guidance in EITF 03-16, we will record a retroactive cumulative effect adjustment equal to the difference between (i) equity earnings from VESCO that would have been recorded using the equity method in prior periods and (ii) the dividend income from VESCO that was recorded using the cost method. We are currently studying the effect that EITF 03-16 will have on our investment in VESCO; however, based on information available, we believe that the implementation of this new accounting guidance will result in an approximate $4 million gain that will be recorded as the cumulative effect of a change in accounting principle.

## OUR CRITICAL ACCOUNTING POLICIES

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

In general, there have been no significant changes in our critical accounting policies since December 31, 2003. For a detailed discussion of these policies, please read *"Management's Discussion and Analysis of Financial Condition and Results of Operations – Our critical accounting policies"* in our annual report on Form 10-K for 2003. The following information summarizes the estimation risk underlying our most significant financial statement items:

*Depreciation methods and estimated useful lives of property, plant and equipment*

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. We use the straight-line method to depreciate our property, plant and equipment. Our estimate of an asset's useful life is based on a number of assumptions including technological changes that may affect the asset's usefulness and the manner in which we intend to physically use the asset. If we subsequently change our assumptions regarding these factors, it would result in an increase or decrease in depreciation expense.

At June 30, 2004 and December 31, 2003, the net book value of our property, plant and equipment was $3.0 billion. For additional information regarding our property, plant and equipment, please read Note 5 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

*Measuring recoverability of long-lived assets and equity method investments*

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Long-lived assets with recorded values that are not expected to be recovered through future expected cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the existing asset. Our estimates of such undiscounted cash flows are based on a number of assumptions including anticipated margins and volumes; estimated useful life of the asset or asset group; and salvage values. An impairment charge would be recorded for the excess of the long-lived asset's carrying value and its fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows but incorporating probabilities that reflect a range of possible outcomes and market value and replacement cost estimates.

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

Our investment in certain unconsolidated affiliates includes excess cost amounts that have been attributed to goodwill. For GulfTerra GP, the excess cost amount attributed to goodwill at June 30, 2004 and December 31, 2003 is $328.2 million. The goodwill amount (which represents potential intangible assets, excess of fair values over carrying values of tangible assets, and remaining goodwill, if any) for GulfTerra GP represents our preliminary allocation of the purchase price pending completion of a fair value analysis which is expected to be completed during the second half of 2004. To the extent that our preliminary allocation of the excess cost of GulfTerra GP is ultimately attributed to depreciable or amortizable assets, our equity earnings from GulfTerra GP will be reduced from what it otherwise would be. For a table showing the impact of potential reclassification of the GulfTerra GP excess cost amount, please read Note 6 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

For the six months ended June 30, 2004 and 2003, we did not record any impairment charges related to our long-lived assets or equity method investments.

*Amortization methods and estimated useful lives of qualifying intangible assets*

Our recorded intangible assets primarily consist of the estimated value assigned to certain contract-based assets representing the rights we own arising from contractual agreements. A contract-based intangible asset with a finite useful life is amortized over its estimated useful life. Our estimate of useful life is based on a number of factors including the expected useful life of related assets (i.e., fractionation facility, pipeline, etc.) and the effects of obsolescence, demand, competition and other factors. If our underlying assumptions regarding the useful life of an intangible asset change, we then might need to adjust the amortization period of such asset which would increase or decrease amortization expense. Additionally, if we determine that an intangible asset's unamortized cost may not be recoverable due to impairment, this would result in a charge against earnings.

At June 30, 2004 and December 31, 2003, the carrying value of our intangible asset portfolio was $261.2 million and $268.9 million. For additional information regarding our intangible assets, please read Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

*Methods we employ to measure the fair value of goodwill*

Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired. Goodwill is not amortized. Instead, goodwill is tested for impairment at a reporting unit level annually, and more frequently, if circumstances warrant. This testing involves calculating the fair value of a reporting unit, which in turn is based on our assumptions regarding the future economic prospects of the reporting unit. If the fair value of the reporting unit (including related goodwill) is less than its book value, a charge to earnings would be required to reduce the carrying value of goodwill to its implied fair value. If our underlying assumptions regarding the future economic prospects of a reporting unit change, this could further impact the fair value of the reporting unit and result in an additional charge to earnings to reduce the carrying value of goodwill.

At June 30, 2004 and December 31, 2003, the carrying value of our goodwill was $82.4 million. For additional information regarding our goodwill, please read Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

*Our revenue recognition polices*

In general, we recognize revenue from our customers when all of the following criteria are met: (i) firm contracts are in place, (ii) delivery has occurred or services have been rendered, (iii) pricing is fixed and determinable and (iv) collectibility is reasonably assured. When contracts settle (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), we determine if an allowance is necessary and record it accordingly. Historically, the consolidated revenues we recorded were not materially based on estimates. However, as SEC regulations require us to submit financial information on increasingly accelerated timeframes, our use of estimates will increase. We believe the assumptions underlying any revenue estimates that we might use will not prove to be materially different from actual amounts due to our development and implementation of a fully integrated volume management system that is inclusive of operational activities through financial accounting.

## RELATED PARTY TRANSACTIONS

*Relationship with EPCO*

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director (and Chairman of the Board of Directors) of our General Partner. In addition, the executive and other officers of our General Partner are employees of EPCO, including O.S. Andras who is President and Chief Executive Officer and a director of the General Partner. The principal business activity of the General Partner is to act as our managing partner. Collectively, EPCO and its affiliates owned a 53.3% equity interest in Enterprise at June 30, 2004, which includes the 2% ownership interest of our General Partner (of which EPCO and its affiliates own 100%).

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

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

We and our General Partner are each separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from EPCO and its other affiliates. EPCO primarily depends on cash distributions it receives as an equity owner in us and our General Partner to fund EPCO's other operations and to meet its debt obligations. For the six months ended June 30, 2004 and 2003, EPCO received $93.9 million and $81.1 million in distributions from us and our General Partner.

*Relationship with Shell*

We have a significant commercial relationship with Shell as a partner, customer and vendor. At June 30, 2004, Shell owned an approximate 16.9% equity interest in Enterprise. Shell is one of our largest customers. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from Shell.

*Relationship with unconsolidated affiliates*

Our significant related party transactions with unconsolidated affiliates consist of the sale of natural gas to Evangeline, purchase of pipeline transportation services from Dixie and purchase of NGL storage, transportation and fractionation services from Promix. In addition, we sell natural gas to Promix.

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

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| **Revenues** | | | | |
| EPCO and affiliates | $75 | $996 | $2,218 | $1,559 |
| Shell and affiliates | 144,884 | 79,216 | 248,984 | 161,436 |
| Unconsolidated affiliates | 57,838 | 39,139 | 106,898 | 89,160 |
| **Operating costs and expenses** | | | | |
| EPCO and affiliates | 39,514 | 27,940 | 78,627 | 74,145 |
| Shell and affiliates | 180,012 | 141,227 | 346,842 | 312,941 |
| Unconsolidated affiliates | 6,906 | 5,864 | 16,488 | 22,347 |
| **Selling, general and administrative costs** | | | | |
| EPCO and affiliates | 5,745 | 6,957 | 12,639 | 13,341 |

## OTHER ITEMS

*Cumulative effect of change in accounting principle recorded in first quarter of 2004*

On January 1, 2004, our majority owned BEF subsidiary changed its method of accounting for planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method. These major maintenance costs, which typically result in facility shutdowns for 30 to 45 days, are principally comprised of amounts paid to third parties for materials, contract services, and other related items.

We have historically used the expense-as-incurred method for planned major maintenance activities. The change in accounting for our majority owned BEF subsidiary conforms to the Company's accounting for all planned major maintenance costs and changes the method to better reflect expenses in the period incurred. As such, we believe the change is to a method that is preferable under the circumstances.

The cumulative effect of this accounting change for years prior to 2004, which is shown separately in the Statement of Consolidated Operations and Comprehensive Income, resulted in a gross benefit of $7 million being recorded on January 1, 2004. After adjusting for the minority interest portion, the net effect on our earnings is $4.7 million. For information regarding the effect of this change on basic and diluted earnings per unit, please read Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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

| | For the Three Months Ended June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| **Pro Forma income statement amounts:** | | | | |
| Historical net income | $ 33,075 | $ 33,105 | $ 91,616 | $ 73,610 |
| *Adjustments to derive pro forma net income:* | | | | |
| Remove historical equity in losses recorded for BEF | | 3,228 | | 6,669 |
| Record equity earnings from BEF calculated using new method of accounting for major maintenance costs | | (2,803) | | (7,225) |
| Remove cumulative effect of change in accounting principle recorded on January 1, 2004 | | | (7,013) | |
| Remove minority interest expense associated with change in accounting principle – Sun 33.3% portion | | | 2,338 | |
| Pro forma net income | $ 33,075 | $ 33,530 | $ 86,941 | $ 73,054 |
| General Partner interest | (6,840) | (5,081) | (14,069) | (9,209) |
| Pro forma net income available to limited partners | $ 26,235 | $ 28,449 | $ 72,872 | $ 63,845 |
| **Pro forma per unit data (basic):** | | | | |
| Units outstanding | 230,189 | 191,935 | 224,326 | 189,079 |
| Per unit data: | | | | |
| Net income before General Partner interest | $ 0.14 | $ 0.17 | $ 0.39 | $ 0.39 |
| Limited partner interest in net income | $ 0.11 | $ 0.15 | $ 0.32 | $ 0.34 |
| **Pro forma per unit data (diluted):** | | | | |
| Units outstanding | 230,625 | 201,935 | 224,822 | 199,079 |
| Per unit data: | | | | |
| Net income before General Partner interest | $ 0.14 | $ 0.17 | $ 0.39 | $ 0.37 |
| Limited partner interest in net income | $ 0.11 | $ 0.14 | $ 0.32 | $ 0.32 |

## ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to the variability of future earnings, cash flows and fair value of certain debt securities caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative (or "trading") purposes.

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

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument's gains and losses offset the related results of the hedged item in the Statement of Operations and Comprehensive Income for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses on a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

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

Due to the complexity of SFAS No. 133 (as amended and interpreted), the FASB is continuing to provide guidance about implementation issues. Since this guidance is still continuing, our conclusions regarding the application of guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of this guidance. For additional information regarding our financial instruments, please read Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

*Interest rate risk hedging program*

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

We manage a portion of our interest rate risks by utilizing interest rate swaps and similar arrangements. The objective of entering into this type of arrangement is to manage debt service costs by converting a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. In general, an interest rate swap requires one party to pay a fixed interest rate on a defined (or "notional") amount while the other party pays a variable rate based on the same notional amount. The notional amount specified in an interest rate swap agreement does not represent exposure to credit loss. We monitor our positions and the credit ratings of counterparties. Management believes the risk of incurring a credit loss on these financial instruments is remote, and that if incurred, such losses would be minimal. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt.

*Fair value hedges – Interest rate swaps.* On January 8, 2004, we entered into three interest rate swap agreements under which we exchanged the payment of fixed rate interest on a portion of principal outstanding under Senior Notes B and C for variable rate interest:

| Hedged Fixed Rate Debt | Period Covered by Swap | Termination Date of Swap | Fixed to Variable Rate (1) | Notional Amount |
|---|---|---|---|---|
| Senior Notes B, 7.50% fixed rate, due Feb. 2011 | Jan. 2004 to Feb. 2011 | Feb. 2011 | 7.50% to 4.6% | $50 million |
| Senior Notes C, 6.375% fixed rate, due Feb. 2013 | Jan. 2004 to Feb. 2013 | Feb. 2013 | 6.375% to 3.1% | $100 million |
| Senior Notes C, 6.375% fixed rate, due Feb. 2013 | Jan. 2004 to Feb. 2013 | Feb. 2013 | 6.375% to 3.1% | $100 million |

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

We have designated these interest rate swaps as fair value hedges under SFAS No. 133 since they mitigate changes in the fair value of the underlying fixed rate debt. These agreements have a combined notional amount of $250 million and match the maturity dates of the underlying debt being hedged. Under the swap agreements, we pay the counterparty a variable rate based on six-month LIBOR (plus an applicable margin) and receive back from the counterparty a fixed rate payment equal to the stated interest rate of the debt being hedged, based on the notional amounts for each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the "settlement period").

As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense. However, the interest rate swaps effectively converts a portion of the underlying fixed rate debt (i.e., the notional amounts hedged for Senior Notes B and C) into variable rate debt. As a result, interest expense will vary depending on the variable rates payable by us under terms of the swap agreements at the end of each settlement period. To the extent that the variable rate amount payable by us at the end of each settlement period is less than the fixed rate amount receivable from the counterparty, we will amortize the difference ratably to earnings as a reduction in interest expense over the settlement period. If the variable rate payable by us at the end of each settlement period is more than the fixed rate amount receivable from the counterparty, we would amortize this difference ratably to earnings as an increase in interest expense over the settlement period.

Total fair value of the interest rate swaps at June 30, 2004 was a payable of approximately $10.1 million with an offsetting increase in fair value of the underlying debt. Interest expense in our Statements of Consolidated Operations and Comprehensive Income for the three and six months ended June 30, 2004 reflect a $2 million and $3.7 million benefit, respectively, from these swaps.

The following tables show the effect of hypothetical price movements on the fair value ("FV") of our interest rate swaps and potential change in the fair value of the debt at the dates indicated:

| Scenario | Resulting Classification | Swap FV at 06/30/04 | Change in Fair Value of Debt |
|---|---|---|---|
| FV assuming no change in underlying interest rates | *Asset (Liability)* | $ (10.1) | $ 10.1 |
| FV assuming 10% increase in underlying interest rates | *Asset (Liability)* | (19.6) | 19.6 |
| FV assuming 10% decrease in underlying interest rates | *Asset (Liability)* | 0.7 | (0.7) |

| Scenario | Resulting Classification | Swap FV at 07/28/04 | Change in Fair Value of Debt |
|---|---|---|---|
| FV assuming no change in underlying interest rates | *Asset (Liability)* | $ (9.6) | $ 9.6 |
| FV assuming 10% increase in underlying interest rates | *Asset (Liability)* | (19.1) | 19.1 |
| FV assuming 10% decrease in underlying interest rates | *Asset (Liability)* | (0.1) | 0.1 |

The fair value of the interest rate swaps excludes the benefit we have already recorded in earnings. The change in fair value between June 30, 2004 and July 28, 2004 is primarily due to a decrease in market interest rates.

*Cash flow hedges – Forward starting interest rate swaps.* On March 17, 2004, we entered into four forward starting interest rate swap transactions with original maturities of September 30, 2004. A forward starting swap is an agreement that effectively hedges the price on a specific U.S. treasury security for an established period of time. The purpose of these transactions was to effectively hedge the underlying U.S. treasury interest rate associated with our anticipated issuance of fixed rate debt, the proceeds of which would be used (either separately or in combination) to finance the GulfTerra merger, to refinance debt initially incurred to complete the merger or to refinance the indebtedness of GulfTerra. The forward starting interest rate swaps have been designated as cash flow hedges under SFAS No. 133. The notional amount of the anticipated debt issuances is approximately $2 billion.

On April 23, 2004, we elected to terminate these financial instruments in order to manage and maximize the value of the swaps and to reduce future debt service costs. As a result, we received $104.5 million in cash from the counterparties. This amount will be amortized over the life of the anticipated debt (when issued) as a reduction to interest expense. The following table shows the portfolio of forward starting swaps categorized by the term of the underlying anticipated debt offering:

| Term of Anticipated Debt Offering (or Forecasted Transaction) | Notional Amount of Anticipated Debt covered by Forward Starting Swaps | Cash Received upon Settlement of Forward Starting Swaps in April 2004 |
|---|---|---|
| 5-year, fixed rate debt instrument | $ 500.0 | $ 18.7 |
| 10-year, fixed rate debt instrument | 500.0 | 26.1 |
| 15-year, fixed rate debt instrument | 500.0 | 29.4 |
| 30-year, fixed rate debt instrument | 500.0 | 30.3 |
| Total | $ 2,000.0 | $ 104.5 |

The gain of $104.5 million in cash received was recorded as a component of AOCI in our Statement of Consolidated Partners' Equity and as an addition to comprehensive income in our Statement of Consolidated Operations and Comprehensive Income for the three and six months ended June 30, 2004.

*Effect of financial instruments on AOCI*

The following table summarizes the effect of our cash flow hedging financial instruments on accumulated other comprehensive income, or AOCI, since January 1, 2003. Information for the first six months of 2004 has been presented by quarter.

| | February 2003 Treasury Locks | April 2004 Forward-Starting Interest Rate Swaps | AOCI Total |
|---|---|---|---|
| Gain on settlement of February 2004 treasury locks | $ 5,354 | | $ 5,354 |
| Amortization of gain on settlement of cash flow hedge to interest expense | (364) | | (364) |
| Balance, January 1, 2004 | 4,990 | | 4,990 |
| Amortization of gain on settlement of cash flow hedge to interest expense | (102) | | (102) |
| Fair value of forward-starting interest rate swaps | | $ 16,973 | 16,973 |
| Balance, March 31, 2004 | 4,888 | 16,973 | 21,861 |
| Reclassification of change in fair value | | (16,973) | (16,973) |
| Gain on settlement of April 2004 forward-starting interest rate swaps | | 104,531 | 104,531 |
| Amortization of gain on settlement of cash flow hedge to interest expense | (104) | | (104) |
| Balance, June 30, 2004 | $ 4,784 | $ 104,531 | $ 109,315 |

*Commodity risk hedging program*

The prices of natural gas, NGLs, petrochemical products and MTBE are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with our Processing segment activities, we may enter into various commodity financial instruments. The primary purpose of these risk management activities is to hedge our exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

We do not hedge our exposure related to MTBE price risks. In addition, we generally do not hedge risks associated with the petrochemical marketing activities that are part of our Fractionation segment. In our Pipelines segment, we utilize a limited number of commodity financial instruments to manage the price Acadian Gas charges certain of its customers for natural gas. Lastly, we do not employ commodity financial instruments in our fee-based marketing business classified under the Other segment.

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

The fair value of our commodity financial instrument portfolio at July 29, 2004, June 30, 2004 and December 31, 2003 and the results of our commodity hedging activities for the three and six months ended June 30, 2004 and 2003 were all nominal amounts. During both the first six months of 2004 and the first six months of 2003, we utilized a limited number of commodity financial instruments.

## ITEM 4. CONTROLS AND PROCEDURES.

Our management, with the participation of the CEO and CFO of our General Partner, have evaluated the effectiveness of our disclosure controls and procedures, including internal controls over financial reporting, as of the end of the period covered by this report. Collectively, these disclosure controls and procedures are designed to provide us with a reasonable assurance that the information required to be disclosed in periodic reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also designed to provide reasonable assurance that such information is accumulated and communicated to our management, including our General Partner's CEO and CFO, as appropriate to allow such persons to make timely decisions regarding required disclosures.

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

Based on their evaluation, the CEO and CFO of our General Partner have concluded that our disclosure controls and procedures are effective to ensure that material information relating to our partnership is made known to management on a timely basis. The CEO and CFO noted no significant deficiencies or material weaknesses in the design or operation of our internal controls over financial reporting that are likely to adversely affect our ability to record, process, summarize and report financial information. Also, they detected no fraud involving management or employees who have a significant role in our internal controls over financial reporting. There have been no significant changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) or in other factors that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

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

## PART II. OTHER INFORMATION.

### ITEM 2. CHANGES IN SECURITIES, USE OF PROCEEDS AND ISSUER PURCHASES OF EQUITY SECURITIES.

We did not repurchase any of our common units or Class B special units during the three or six month period ended June 30, 2004. As of June 30, 2004, we and our affiliates are authorized to repurchase up to 618,400 common units under the December 1998 common unit repurchase program. Any common units repurchased under this publicly announced program are classified as treasury units.

Upon the approval of our unitholders at a special meeting held on July 29, 2004, all of our Class B special units converted to an equal number of common units.

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

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

We held a special meeting of our common unitholders to vote on these matters in Houston, Texas on July 29, 2004. The proxy solicitation materials were first mailed to unitholders on or about June 24, 2004. The following table summarizes the results of this special meeting:

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

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

### ITEM 5. OTHER INFORMATION.

GulfTerra also held a special meeting of its unitholders in Houston, Texas on July 29, 2004. At this meeting, GulfTerra's common and Series C unitholders were asked by the board of directors of GulfTerra's general partner to approve and adopt the merger agreement with Enterprise. The following table summarizes the results of this special meeting:

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

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

## ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K.

*(a) Exhibits*

| Exhibit No. | Exhibit* |
|---|---|
| 2.1 | Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (including the forms of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, Exchange and Registration Rights Agreement and Performance Guaranty, to be entered into by the parties named therein in connection with the merger of Enterprise and GulfTerra, attached as Exhibits 1, 2 and 3, respectively, thereto) (incorporated by reference to Exhibit 2.1 to the Form 8-K filed April 21, 2004). |
| 3.1 | First Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC dated as of September 17, 1999 (incorporated by reference to Exhibit 99.8 to the Form 8-K/A-1 filed October 27, 1999). |
| 3.2 | Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC dated as of September 19, 2002 (incorporated by reference to Exhibit 3.2 to Form 10-K filed March 31, 2003). |
| 3.3 | Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. dated as of July 31, 1998 (restated to include all agreements through December 10, 2003). |
| 3.4 | Reorganization Agreement, dated as of December 10, 2003, among Enterprise Products Partners, L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products OLPGP, Inc. (incorporated by reference to Exhibit 3.1 to Form 8-K filed December 10, 2003). |
| 3.5 | Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated May 15, 2002 (restated to include all amendments through December 17, 2003) (incorporated by reference to Exhibit 3.1 to Form 8-K filed February 10, 2004). |
| 4.1 | Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000). |
| 4.2 | First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003). |
| 4.3 | Global Note representing $350 million principal amount of 6.375% Series A Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003). |
| 4.4 | Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003). |
| 4.5 | Registration Rights Agreement dated as of January 22, 2003, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.5 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003). |
| 4.6 | Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003). |
| 4.7 | Rule 144 A Global Note representing $499.2 million principal amount of 6.875% Series A Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003). |
| 4.8 | Regulation S Global Note representing $800,000 principal amount of 6.875% Series A Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 10-K filed March 31, 2003). |

4.9 Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
4.10 Registration Rights Agreement dated as of February 14, 2003, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.10 to Form 10-K filed March 31, 2003).
4.11 Global Note representing $350 million principal amount of 8.25% Senior Notes due 2005 (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 10, 2000).
4.12 Global Notes representing $450 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.13 Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.14 $250 Million Multi-Year Revolving Credit Facility dated as of November 17, 2000, among Enterprise Products Operating L.P., First Union National Bank, as Administrative Agent, Bank One, NA, as Documentation Agent, the Chase Manhattan Bank, as Syndication Agent, and the several banks from time to time parties thereto, with First Union Securities, Inc. and Chase Securities Inc. as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 4.2 to Form 8-K filed January 24, 2001).
4.15 Guaranty Agreement dated as of November 17, 2000, by Enterprise Products Partners L.P. in favor of First Union National Bank, as Administrative Agent, with respect to the $250 Million Multi-Year Revolving Credit Facility included as Exhibit 4.4 above (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 24, 2001).
4.16 First Amendment to Multi-Year Credit Facility dated April 19, 2001 (incorporated by reference to Exhibit 4.12 to Form 10-Q filed May 14, 2001).
4.17 Second Amendment to Multi-Year Revolving Credit Facility dated April 14, 2002 (incorporated by reference to Exhibit 4.14 to Form 10-Q filed May 14, 2002).
4.18 Third Amendment to Multi-Year Revolving Credit Facility dated July 31, 2002 (incorporated by reference to Exhibit 4.1 to Form 10-Q filed August 12, 2002).
4.19 Contribution Agreement dated September 17, 1999 (incorporated by reference to Exhibit "B" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.20 Registration Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "E" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.21 Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "C" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.22 Amendment No. 1, dated September 12, 2003, to Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit 4.1 to Form 8-K filed September 15, 2003).
4.23 364-Day Revolving Credit Agreement dated as of October 30, 2003, among Enterprise Products Operating L.P., Wachovia Bank, National Association, as Administrative Agent, Bank One, N.A., as Syndication Agent, Royal Bank of Canada, The Bank of Nova Scotia and SunTrust Bank, as Co-Documentation Agents, and the several lenders from time to time parties thereto, with Wachovia Capital Markets, LLC and Banc One Capital Markets, Inc., as Joint Lead Arrangers, and Wachovia Capital Markets, LLC, as Sole Manager (incorporated by reference to Exhibit 4.29 to Form 10-Q filed November 13, 2003).
4.24 Guaranty Agreement dated as of October 30, 2003 by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent, with respect to 364-Day Revolving Credit Facility (incorporated by reference to Exhibit 4.30 to Form 10-Q filed November 13, 2003).
4.25 Fourth Amendment to Multi-Year Revolving Credit Facility dated October 30, 2003 (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 13, 2003).
4.26 Voting Agreement and Proxy, dated as of December 15, 2003, by and among GulfTerra Energy Partners, L.P., Enterprise Products Delaware Holdings, L.P., the Duncan Family 2000 Trust and Dan L. Duncan (incorporated by reference to Exhibit 4.1 to Schedule 13D, Amendment No. 2, filed December 18, 2003).
4.27 Interim Term Loan Agreement dated December 12, 2003, among Enterprise Products Operating L.P., Lehman Commercial Paper Inc., as Administrative Agent, Bank One NA, The Bank of Nova Scotia, SunTrust Bank and Wachovia Bank, National Association, as Co-Syndicating Agents, and

the several banks from time to time parties thereto. (incorporated by reference to Exhibit 4.1 to Form 8-K filed February 10, 2004).

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

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

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

4.31 $1.2 Billion 364-Day Term Credit Facility dated as of July 31, 2002, among Enterprise Products Operating Partnership L.P., Wachovia Bank, National Association, as Administrative Agent, Lehman Commercial Paper Inc., as Co-Syndication Agent, Royal Bank of Canada, as Co-Syndication Agent and Arranger, with Wachovia Securities, Inc. and Lehman Brothers Inc., as Lead Arrangers and Joint Bookrunners and RBC Capital Markets, as Arranger (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 12, 2002).

4.32 Guaranty Agreement dated as of July 31, 2002 by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent, with respect to the $1.2 Billion 364-Day Term Credit Facility (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 12, 2002).

10.1 Seventh Amendment to Conveyance of Gas Processing Rights, dated as of April 1, 2004 among Enterprise Gas Processing, LLC, Shell Oil Company, Shell Exploration & Production Company, Shell Offshore Inc., Shell Consolidated Energy Resources Inc., Shell Land & Energy Company, Shell Frontier Oil & Gas Inc. and Shell Gulf of Mexico Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 26, 2004).

10.2 Enterprise Products 1998 Long-Term Incentive Plan, amended and restated as of April 8, 2004 (incorporated by reference to Appendix B to Notice of Written Consent dated April 22, 2004, filed April 22, 2004).

10.3 Form of Restricted Unit Grant under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.3 to Form S-8 Registration Statement, Reg. No. 333-115633).

18.1 Letter regarding Change in Accounting Principles dated May 4, 2004 (incorporated by reference to Exhibit 18.1 to Form 10-Q filed May 10, 2004).

31.1# Sarbanes-Oxley Section 302 certification of O.S. Andras for Enterprise Products Partners L.P. for the June 30, 2004 quarterly report on Form 10-Q.

31.2# Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the June 30, 2004 quarterly report on Form 10-Q.

32.1# Sarbanes-Oxley Section 1350 certification of O.S. Andras for the June 30, 2004 quarterly report on Form 10-Q.

32.2# Sarbanes-Oxley Section 1350 certification of Michael A. Creel for the June 30, 2004 quarterly report on Form 10-Q.

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P. is 1-14323.

# Filed with this report.

*(b) Reports on Form 8-K.*

*April 16, 2004 filing, Item 7.* On April 16, 2004, we filed certain audited combined financial statements of El Paso Hydrocarbons, L.P. and El Paso NGL Marketing Company, L.P. These financial statements relate to the South Texas midstream energy assets we expect to acquire from El Paso in Step Three of our proposed merger with GulfTerra. We filed these financial statements so that they would be incorporated by reference into our currently effective registration statements.

*April 20, 2004 filing, Item 7.* On April 20, 2004, we filed certain audited financial statements of GulfTerra Energy Partners, L.P. and subsidiaries and Poseidon Oil Pipeline Company, L.L.C. We filed these financial statements so that they would be incorporated by reference into our currently effective registration statements.

*April 21, 2004 filing, Items 5 and 7.* On April 21, 2004, we announced that El Paso and our General Partner had amended certain ownership transactions related to our proposed merger with GulfTerra. A copy of the press release and amendment were filed as exhibits.

*April 22, 2004 filing, Items 7 and 12.* On April 22, 2004, we issued a press release regarding our financial results for the three months ended March 31, 2004 and 2003. A copy of the press release was filed as an exhibit.

*April 26, 2004 filing, Items 5 and 7.* On April 26, 2004, we announced an amendment to our natural gas processing agreement with Shell. A copy of the edited amendment was filed as an exhibit.

*April 26, 2004 filing, Item 5.* On April 26, 2004, we filed excerpts from the May 2004 prospectus supplement and accompanying prospectus.

*April 27, 2004 filing, Items 5 and 7.* On April 27, 2004, we filed updated consents from independent accountants and independent petroleum engineers and geologists in connection with our effective registration statements.

*May 3, 2004 filing, Items 5 and 7.* On April 29, 2004, we filed an underwriting agreement for the public offering of 15,000,000 common units in May 2004. The underwriting agreement, legal opinions and related consents were filed as exhibits.

*June 16, 2004 filing, Item 7.* On June 16, 2004, we filed the unaudited combined financial statements of El Paso Hydrocarbons, L.P. and El Paso NGL Marketing Company, L.P. for the first quarter of 2004.

## SIGNATURES

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

**ENTERPRISE PRODUCTS PARTNERS L.P.**
(A Delaware Limited Partnership)

By: Enterprise Products GP, LLC,
as General Partner

By: Michael J. Knesek

Name: Michael J. Knesek
Title: Vice President, Controller and Principal Accounting Officer of the General Partner

**EXHIBIT 31.1**

## SARBANES-OXLEY SECTION 302 CERTIFICATION

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

I, O.S. Andras, the Principal Executive Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others with those entities, particularly during the period in which this report is being prepared;
   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent function):

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

Date: August 9, 2004

O S Andras

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

**EXHIBIT 31.2**

## SARBANES-OXLEY SECTION 302 CERTIFICATION

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

I, Michael A. Creel, the Principal Financial Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others with those entities, particularly during the period in which this report is being prepared;
    b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent function):

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

Date: August 9, 2004

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

**EXHIBIT 32.1**

**SARBANES-OXLEY SECTION 906 CERTIFICATION**

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

In connection with this quarterly report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-Q for the three and six months ended June 30, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, O.S. Andras, Chief Executive Officer of Enterprise Products GP, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

O.S. Andras

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

Date: August 9, 2004

**EXHIBIT 32.2**

**SARBANES-OXLEY SECTION 906 CERTIFICATION**

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

In connection with this quarterly report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-Q for the three and six months ending June 30, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Financial Officer of Enterprise Products GP, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

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

Date: August 9, 2004