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

FORM 8-K

CURRENT REPORT

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

Date of Report (date of earliest event reported) : **June 15, 2006**

Commission File No. 1-10403

TEPPCO Partners, L.P.
(Exact name of Registrant as specified in its charter)

Delaware	**76-0291058**
(State of Incorporation or Organization)	**(I.R.S. Employer Identification Number)**

1100 Louisiana
P.O. Box 2521
Houston, Texas 77252-2521
(Address of principal executive offices, including zip code)

(713) 381-3636
(Registrant's telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

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

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

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

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

Item 8.01. Other Events.

TEPPCO Partners, L.P. ("the Partnership") is filing this Current Report on Form 8-K to provide supplemental financial disclosure relating to the sale of its ownership interest in its Pioneer plant, described below, in March 2006 and the resulting classification of the Pioneer plant as discontinued operations.

On March 31, 2006, the Partnership sold its ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah Gas Gathering Company's ("Jonah") rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise Products Partners L.P. ("Enterprise") for $38.0 million in cash. The carrying value of the Pioneer plant at March 31, 2006, prior to the sale, was $19.7 million. Costs associated with the completion of the transaction are estimated to be approximately $0.4 million at March 31, 2006.

Under Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, the Partnership classifies assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approval by its management or Board of Directors and when they meet other criteria. As of March 31, 2006, the Partnership had completed the sale of the Pioneer plant and accordingly classified those operations as discontinued operations for all periods presented in its Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006 ("March 2006 Quarterly Report").

The Partnership has recast in Exhibit 99.1 hereto, which is incorporated by reference, information presented in the following items in its Annual Report on Form 10-K for the fiscal year ended December 31, 2005, filed with the Securities and Exchange Commission on March 1, 2006 (the "2005 Annual Report") to conform to its presentation of the Pioneer plant as discontinued operations:

- Item 6 — Selected Financial Data,
- Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations,

- Item 8 — Financial Statements and Supplementary Data and

- Item 13 — Certain Relationships and Related Transactions.

Except with respect to the limited matters described above, the recast information included in this report has not been updated to reflect events subsequent to the filing of the 2005 Annual Report. This report should be read in conjunction with the portions of the 2005 Annual Report that have not been recast herein, as well as in conjunction with the March 2006 Quarterly Report and other Current Reports on Form 8-K filed by the Partnership after the 2005 Annual Report.

Cautionary Note Regarding Forward-Looking Statements

The matters discussed in this report include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements that express belief, expectation, estimates or intentions, as well as those that are not statements of historical facts are forward-looking statements. The words "proposed", "anticipate", "potential", "may", "will", "could", "should", "expect", "estimate", "believe", "intend", "plan", "seek" and similar expressions are intended to identify forward-looking statements. Without limiting the broader description of forward-looking statements above, the Partnership specifically notes that statements included in this document that address activities, events or developments that the Partnership expects or anticipates will or may occur in the future, including such things as estimated future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strengths, goals, expansion and growth of the Partnership's business and operations, plans, references to future success, references to intentions as to future matters and other such matters are forward-looking statements. These statements are based on certain assumptions and analyses made by the Partnership in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors the Partnership believes are appropriate under the circumstances. While the Partnership believes its expectations reflected in these forward-looking statements are reasonable, whether actual results and developments will conform

with its expectations and predictions is subject to a number of risks and uncertainties, including general economic, market or business conditions, the opportunities (or lack thereof) that may be presented to and pursued by the Partnership, competitive actions by other pipeline companies, changes in laws or regulations and other factors, many of which are beyond the Partnership's control. For example, the demand for refined products is dependent upon the price, prevailing economic conditions and demographic changes in the markets served, trucking and railroad freight, agricultural usage and military usage; the demand for propane is sensitive to the weather and prevailing economic conditions; the demand for petrochemicals is dependent upon prices for products produced from petrochemicals; the demand for crude oil and petroleum products is dependent upon the price of crude oil and the products produced from the refining of crude oil; and the demand for natural gas is dependent upon the price of natural gas and the locations in which natural gas is drilled. The Partnership is also subject to regulatory factors such as the amounts it is allowed to charge its customers for the services it provides on its regulated pipeline systems. Consequently, all of the forward-looking statements made in this document are qualified by these cautionary statements, and the Partnership cannot assure that actual results or developments that it anticipates will be realized or, even if substantially realized, will have the expected consequences to or effect on the Partnership or its business or operations. Also note that the Partnership provides a cautionary discussion of risks and uncertainties under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report and the March 2006 Quarterly Report and under the caption "Risk Factors" and elsewhere in the 2005 Annual Report and the March 2006 Quarterly Report.

The forward-looking statements contained in this report speak only as of March 1, 2006, except to the extent they have been updated to reclassify the operations of the Partnership's Pioneer plant as discontinued operations, as described above. Forward-looking statements made herein may have been or may be superseded by statements made in the March 2006 Quarterly Report or other filings by the Partnership with the Securities and Exchange Commission after March 1, 2006. Except as required by the federal and state securities laws, the Partnership undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason. All forward-looking statements attributable to the Partnership or any person acting on its behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this report and in its future periodic reports filed with the Securities and Exchange Commission. In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this report may not occur.

Item 5.03. Amendments to Articles of Incorporation or Bylaws; Change in Fiscal Year.

DFI GP Holdings L.P. ("DFI"), the sole member of the general partner of the Partnership, has amended the limited liability company agreement of the general partner (the "LLC Agreement") to allow certain committees of the board of directors of the general partner to consist of one or more directors and to delete provisions specifying the manner of fixing salaries of officers of the general partner. The amendment was entered into on June 15, 2006 and is effective as of February 24, 2005, the date on which the general partner was acquired by DFI. In connection with its acquisition of the general partner, DFI amended the LLC Agreement in March 2005 to delete a provision regarding retirement of non-employee directors.

Item 9.01. Financial Statements and Exhibits.

(d) Exhibits:

Exhibit Number	Description
3.1*	Amendment to the Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated June 15, 2006, but effective as of February 24, 2005.
3.2	Amendment to Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated March 22, 2005 (Filed as Exhibit 3.3 to Form 10-Q/A of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).

3.3	Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated March 31, 2000 (Filed as Exhibit 3.3 to Form 10-Q/A of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
23*	Consent of KPMG LLP.
99.1*	Item 6 — Selected Financial Data; Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations; Item 8 — Financial Statements and Supplementary Data; and Item 13 — Certain Relationships and Related Transactions from the Partnership's Form 10-K for the year ended December 31, 2005, reflecting the treatment of the Pioneer silica gel natural gas processing plant as discontinued operations.

* Filed herewith.

SIGNATURE

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

TEPPCO Partners, L.P.
(Registrant)

By: Texas Eastern Products Pipeline Company, LLC
General Partner

Date: June 16, 2006

By: /s/ WILLIAM G. MANIAS
William G. Manias
Vice President and
Chief Financial Officer

AMENDMENT
TO
LIMITED LIABILITY COMPANY AGREEMENT OF
OF
TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC

This Amendment to the Limited Liability Company Agreement (this "Amendment") of Texas Eastern Products Pipeline Company, LLC ("TEPPCO GP"), dated June 15, 2006, but effective as of February 24, 2005 (the "Effective Date"), is executed by DFI Holdings L.P. ("DFI"). Capitalized terms used but not defined in this Amendment shall have the meaning set forth in the Limited Liability Company Agreement of TEPPCO GP dated March 31, 2000 (as amended prior to the effective date hereof, the "LLC Agreement").

RECITALS

WHEREAS, DFI Holdings LLC (the "Company") owns a 1% general partner interest in and is the sole general partner of DFI;

WHEREAS, DFI is the sole member of TEPPCO GP;

WHEREAS, TEPPCO GP owns a 2% general partnership interest in TEPPCO Partners, L.P., a Delaware limited partnership ("TEPPCO LP"), and is the sole general partner of TEPPCO LP;

WHEREAS, the Company, in its capacity as general partner of DFI, has determined that it is advisable to amend the LLC Agreement.

NOW, THEREFORE, in consideration of the agreements and obligations set forth herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged and intending to be legally bound, DFI hereby agrees as follows:

AGREEMENT

1. Section 10(a) of the LLC Agreement shall be amended by deleting clause (i) thereof and replacing it with a new clause (i) as follows:

> (i) The Board of Directors may, by resolution passed by a majority of the whole Board, designate one or more committees, each committee to consist of one or more Directors; provided, however, that any Executive Committee designated pursuant to Section 10(b) shall consist of three or more Directors. The Board may designate one or more Directors as alternate members of any committee, who may replace any absent or disqualified member at any meeting of the committee. Except as otherwise provided by law, any such committee shall have and may exercise such powers of the Board of Directors as are provided in the resolution of the Board or set forth in this Agreement.

2. Section 10(a) of the LLC Agreement shall be amended by deleting clause (iii) thereof and replacing it with a new clause (iii) as follows:

> (iii) Regular meetings of a committee may be held without notice at such time and place as shall from time to time be determined by the committee. Special meetings of a committee shall be called by the Secretary at the request of the Chief Executive officer or of any member (in the case of any Executive Committee, any two members) of the committee. Notice of each special meeting of a committee shall be given by the Secretary to each member of the committee. No such notice of any meeting need by given to any member of a committee who attends the meeting or who files a written waiver of notice thereof with the Secretary, either before or after the meeting.

3. Section 11(a) of the LLC Agreement shall be amended by deleting clauses (i) and (ii) thereof and replacing them with new clauses (i) and (ii) as follows:

> (i) The officers of the Company shall be chosen by the Board of Directors. The principal officers shall be a Chief Executive Officer, a President, one or more Vice Presidents (one or more of whom may be designated Executive Vice President, and one or more of whom may be designated Senior Vice President) a Secretary, a Treasurer, a Chief Financial Officer, and a General Counsel. The principal officers shall be elected each year at the first meeting of the Board of Directors. Two or more offices may be held by the same person. The Chief Executive Officer shall be chosen by the Directors from their own number.
>
> (ii) The Board may appoint such other officers, assistant officers and agents as it shall deem necessary, who shall hold their offices for such terms and shall exercise such powers and perform such duties as shall be determined by the Board.

4. Except as otherwise expressly provided by this Amendment, all of the terms, conditions and provisions of the LLC Agreement shall remain the same. This Amendment shall be governed by and construed under the laws of the State of Delaware as applied to agreements entered into solely between residents of, and to be performed entirely within, such state.

IN WITNESS WHEREOF, the undersigned has executed this Amendment to Limited Liability Company Agreement as of June 15, 2006, but effective as of the Effective Date.

DFI GP HOLDINGS L.P.
(Sole Member of Texas Eastern Products Pipeline Company, LLC)

By: DFI Holdings LLC, its general partner

By: /s/ RICHARD H. BACHMANN
Name: Richard H. Bachmann
Title: Executive Vice President

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To Partners of
TEPPCO Partners, L.P.:

We consent to the incorporation by reference in the registration statement (No. 333-110207) on Form S-3, the registration statement (No. 33-81976) on Form S-3, and the registration statement (No. 333-82892) on Form S-8 of TEPPCO Partners, L.P. of our report dated February 28, 2006, except for the effects of discontinued operations, as discussed in Note 5, which is as of June 1, 2006, with respect to the consolidated balance sheets of TEPPCO Partners, L.P. as of December 31, 2005 and 2004, and the related consolidated statements of income, partners' capital and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005, which report appears in the Form 8-K of TEPPCO Partners, L.P. dated June 16, 2006.

Our report dated February 28, 2006, except for the effects of discontinued operations, as discussed in Note 5, which is as of June 1, 2006, with respect to the consolidated balance sheets of TEPPCO Partners, L.P. as of December 31, 2005 and 2004 and the related consolidated statements of income, partners' capital and comprehensive income and cash flows for each of the years in the three-year period ended December 31, 2005, contains a separate paragraph that states that as discussed in Note 20 to the consolidated financial statements, the Partnership has restated its consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, partners' capital and comprehensive income and cash flows for the years ended December 31, 2004 and 2003.

KPMG LLP

Houston, Texas
June 16, 2006

Item 6. ***Selected Financial Data***

The following tables set forth, for the periods and at the dates indicated, our selected consolidated financial and operating data. The selected financial data as of December 31, 2005 and 2004, and for the years ended December 31, 2005 and 2004, reflect Jonah Gas Gathering Company's Pioneer plant, which was sold on March 31, 2006, as discontinued operations. The selected financial data as of December 31, 2005, 2004 and 2003 and for the years ended December 31, 2005, 2004 and 2003, is derived from audited consolidated financial statements, which is included elsewhere in this Report. The selected financial data for the years ended December 31, 2002 and 2001, is derived from unaudited consolidated financial statements and, in the opinion of management, has been prepared in accordance with accounting principles generally accepted in the United States of America and reflects all adjustments which are, in the opinion of management, necessary for a fair presentation of results for these periods. With the exception of December 31, 2005, the financial information shown below has been restated to reflect a restatement adjustment for an accounting correction (see also "Explanatory Note" in our Annual Report on Form 10-K and Note 20 in the Notes to the Consolidated Financial Statements). The financial data should be read in conjunction with our audited consolidated financial statements included in the Index to Consolidated Financial Statements on page F-1 of this Report. See also Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	Years Ended December 31,				
	2005	2004 (as restated)	2003 (as restated)	2002 (1) (as restated) (unaudited)	2001 (2) (as restated) (unaudited)
	(in thousands, except per Unit amounts)				
Income Statement Data:					
Operating revenues:					
Sales of petroleum products	$ 8,061,808	$ 5,426,832	$ 3,766,651	$ 2,823,800	$ 3,219,816
Transportation — Refined products	144,552	148,166	138,926	123,476	139,315
Transportation — LPGs	96,297	87,050	91,787	74,577	77,823
Transportation — Crude oil	37,614	37,177	29,057	27,414	24,223
Transportation — NGLs	43,915	41,204	39,837	38,870	20,702
Gathering — Natural gas	152,797	140,122	135,144	90,053	8,824
Mont Belvieu operations	—	—	—	15,238	14,116
Other revenues	68,051	67,539	54,430	48,735	51,594
Total operating revenues	8,605,034	5,948,090	4,255,832	3,242,163	3,556,413
Purchases of petroleum products	7,986,438	5,367,027	3,711,207	2,772,328	3,172,805
Operating expenses	288,502	285,388	255,437	213,556	185,918
Depreciation and amortization	110,729	112,284	100,728	86,032	45,899
Gains on sales of assets	(668)	(1,053)	(3,948)	—	—
Operating income	220,033	184,444	192,408	170,247	151,791
Interest expense — net	(81,861)	(72,053)	(84,250)	(66,192)	(62,057)
Equity earnings	20,094	22,148	12,874	8,853	17,611
Other income — net	1,135	1,320	748	1,827	1,999
Income from continuing operations	159,401	135,859	121,780	114,735	109,344
Income from discontinued operations (3)	3,150	2,689	—	—	—
Net income (4)	162,551	138,548	121,780	114,735	109,344
Amortization of goodwill	—	—	—	—	1,013
Adjusted net income	$ 162,551	$ 138,548	$ 121,780	$ 114,735	$ 110,357

	Years Ended December 31,				
	2005	2004 (as restated)	2003 (as restated)	2002 (1) (as restated) (unaudited)	2001 (2) (as restated) (unaudited)
	(in thousands, except per Unit amounts)				
Basic and diluted income per Unit: (3)(5)					
Continuing operations	$ 1.67	$ 1.53	$ 1.47	$ 1.74	$ 2.19
Discontinued operations	0.04	0.03	—	—	—
Net income per Unit	1.71	1.56	1.47	1.74	2.19
Amortization of goodwill	—	—	—	—	0.02
Adjusted net income per Unit	$ 1.71	$ 1.56	$ 1.47	$ 1.74	$ 2.21

	December 31,				
	2005	2004 (as restated)	2003 (as restated)	2002 (1) (as restated) (unaudited)	2001 (2) (as restated) (unaudited)
	(in thousands)				
Balance Sheet Data:					
Property, plant and equipment — net	$ 1,960,068	$ 1,703,702	$ 1,619,163	$ 1,587,824	$ 1,180,461
Total assets	3,680,538	3,186,284	2,934,480	2,765,900	2,065,952
Long-term debt (net of current maturities)	1,525,021	1,480,226	1,339,650	1,377,692	715,842
Total debt	1,525,021	1,480,226	1,339,650	1,377,692	1,075,842
Class B Units held by related party	—	—	—	103,234	105,678
Partners' capital	1,201,370	1,011,103	1,102,809	889,449	543,737

	Years Ended December 31,				
	2005	2004 (as restated)	2003 (as restated)	2002 (1) (as restated) (unaudited)	2001 (2) (as restated) (unaudited)

	(in thousands, except per Unit amounts)				
Cash Flow Data:					
Net cash provided by continuing operating activities (3)	$ 250,723	$ 263,896	$ 242,424	$ 234,917	$ 169,148
Net cash provided by operating activities	254,505	267,167	242,424	234,917	169,148
Capital expenditures to sustain existing operations	(40,783)	(41,733)	(32,864)	(21,978)	(18,578)
Distributions paid	(251,101)	(233,057)	(202,498)	(151,853)	(104,412)
Distributions paid per Unit (5)	$ 2.68	$ 2.64	$ 2.50	$ 2.35	$ 2.15

(1) Data reflects the operations of the Chaparral and Val Verde assets acquired on March 1, 2002 and June 30, 2002, respectively.

(2) Data reflects the operations of the Jonah assets acquired on September 30, 2001.

(3) Data has been recasted to reflect the Pioneer plant as discontinued operations for the years ended December 31, 2004 and 2005. The Pioneer plant was constructed as part of the Phase III expansion of the Jonah system and was completed during the first quarter of 2004.

(4) See Note 20 of the Notes to Consolidated Financial Statements for the effect of the restatement adjustment on net income for the years ended December 31, 2004 and 2003. The restatement adjustment decreased net income for the year ended December 31, 2002, by $3.1 million, or $0.05 per Unit, and increased net income for the year ended December 31, 2001, by $0.2 million, or $0.01 per Unit, respectively.

(5) Per Unit calculation includes 7,750,000 Units issued in 2001, 13,359,597 Units issued in 2002 and 9,188,957 Units issued in 2003, net of retirement of Class B Units of 3,916,547. No Units were issued in 2004. In 2005, 6,965,000 Units were issued.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

The following information should be read in conjunction with our consolidated financial statements and our accompanying notes listed in the Index to Consolidated Financial Statements on page F-1 of this Report. The following discussion of our financial condition and results of operations reflects the recasting as discontinued operations of the Pioneer plant operations. Our discussion and analysis includes the following:

- Overview of Business.
- Discontinued Operations — Discusses the reflection of the operations of the Pioneer plant as discontinued operations.
- Restatement of Consolidated Financial Statements — Discusses the restatement adjustment.
- Critical Accounting Policies and Estimates — Presents accounting policies that are among the most critical to the portrayal of our financial condition and results of operations.
- Results of Operations — Discusses material period-to-period variances in the consolidated statements of income.
- Financial Condition and Liquidity — Analyzes cash flows and financial position.
- Other Considerations — Addresses available sources of liquidity, trends, future plans and contingencies that are reasonably likely to materially affect future liquidity or earnings.

This discussion contains forward-looking statements based on current expectations that are subject to risks and uncertainties, such as statements of our plans, objectives, expectations and intentions. When used in this discussion, the words "proposed," "anticipate," "potential," "may," "will," "could," "should," "expect," estimate," "believe," "intend," "plan," "seek" and similar expressions are intended to identify forward-looking statements. Our actual results and the timing of events could differ materially from those anticipated or implied by the forward-looking statements discussed here as a result of various factors, including, among others, those set forth under the "Cautionary Note Regarding Forward-Looking Statements" and "Risk Factors" herein. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this Report. Except as required by law, we undertake no obligation to publicly update or revise any of the forward-looking statements in this discussion after the date of this Report.

Overview of Business

Our corporate business strategy is to grow sustainable cash flow and cash distributions to our unitholders. The key elements of our strategy are to focus on internal growth prospects in order to increase the pipeline system and terminal throughput, expand and upgrade existing assets and services and construct new pipelines, terminals and facilities, to target accretive and complementary acquisitions and expansion opportunities that provide attractive growth potential; to maintain an appropriate mix of assets; and to operate in a safe, efficient and environmentally responsible manner.

Certain factors are key to our operations. These include the safe, reliable and efficient operation of the pipelines and facilities that we own or operate while meeting the regulations that govern the operation of our assets and the costs associated with such regulations. We are also focused on our continued growth through expansion of the assets that we own and through the acquisition of assets that complement our current operations. We operate and report in three business segments:

- Our Downstream Segment, which is engaged in the transportation and storage of refined products, LPGs and petrochemicals;

- Our Upstream Segment, which is engaged in the gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals; and

- Our Midstream Segment, which is engaged in the gathering of natural gas, transportation of NGLs and fractionation of NGLs.

Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. The two largest operating expense items of the Downstream Segment are labor and electric power. We generally realize higher revenues during the first and fourth quarters of each year since our operations are somewhat seasonal. Refined products volumes are generally higher during the second and third quarters because of greater demand for gasolines during the spring and summer driving seasons. LPGs volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating. Our Downstream Segment also includes the results of operations of the northern portion of the Dean Pipeline, which transports RGP from Mont Belvieu to Point Comfort, Texas. Our Downstream Segment also includes our equity investments in Centennial and MB Storage (see Note 6 in the Notes to the Consolidated Financial Statements).

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale of the crude oil to local refineries, marketers or other end users. Our Upstream Segment also includes our equity investment in Seaway (see Note 6 in the Notes to the Consolidated Financial Statements). Seaway consists of large diameter pipelines that transport crude oil from Seaway’s marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

Our Midstream Segment revenues are earned from the gathering of natural gas in the Green River Basin in southwestern Wyoming, through Jonah, and the gathering of CBM and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde; transportation of NGLs from two trunkline NGL pipelines in South Texas, two NGL pipelines in East Texas and a pipeline system (Chaparral) from West Texas and New Mexico to Mont Belvieu; and the fractionation of NGLs in Colorado.

We continued building a base for long-term growth by enhancing existing systems and pursuing new business opportunities. We increased throughput on our pipeline systems, constructed new pipeline and gathering systems, and expanded and upgraded our existing infrastructure. In 2005, our major accomplishments included:

- Substantially completing the Phase IV expansion on the Jonah system, increasing capacity to approximately 1.5 billion cubic feet per day.
- Benefiting from a full year of revenues and volumes from the connection to a gathering system in Colorado on Val Verde.
- Opening a refined products truck loading terminal in Bossier City, Louisiana, to provide the Northwest Louisiana and East Texas markets with access to 20,000 additional barrels per day of delivery capacity of Gulf Coast sourced gasoline and diesel fuel.
- Expanding our Gulf Coast refined products infrastructure, which included the acquisition of a 90-mile pipeline and 5.5 million barrels of storage in the Houston, Texas, area.
- Continuing the expansion of our Northeast LPGs pipeline system.
- Acquiring a refined products terminal and truck rack in North Little Rock, Arkansas, to complement our existing infrastructure.
- Acquiring 945,000 barrels of crude oil storage in Cushing, Oklahoma, which provides additional terminaling and storage opportunities for Mid-Continent refiners, and enables us to strengthen our gathering and marketing business.
- Integrating a 158-mile crude oil pipeline in Southeast Texas into our South Texas system, which will provide increased market flexibility for our customers and future growth opportunities.

In 2006, we remain confident that our business strategy will provide continued growth in earnings and cash distributions. This growth potential is based on:

- Continued development of the Jonah system which serves the Jonah and Pinedale fields in our Midstream Segment, as we increase throughput on the Jonah system with the completion of our Phase IV expansion in February 2006. Through the Jonah Expansion, we expect to increase the capacity to 2 billion cubic feet per day, which should be completed in the fourth quarter of 2006.
- Growth in our Downstream Segment, resulting from both our expanding gathering system capacity and the continued capacity of Centennial, additional acquisitions and the growing demand for Gulf Coast sourced product. Centennial continues to provide us with additional system capacity to move additional refined products to the Chicago, Illinois, market areas.
- Substantially completing an expansion project to increase delivery capacity of gasoline and diesel fuel to the Indianapolis, Indiana, and Chicago market areas.
- Strengthening our existing market base in our Upstream Segment, as we integrate our 2005 acquisitions into our existing asset base and concentrate on future acquisitions to expand our core operating areas.
- Continued growth in our Upstream Segment, resulting from expansions of our West Texas systems and storage capacity at Cushing.
- Adding new volumes and improving the operating efficiency of the Val Verde system in New Mexico’s San Juan Basin, through new connections of conventional and Colorado coal seam gas.
- Increasing the throughput on our NGL systems.

Our Upstream Segment’s performance will be impacted by a decrease in our participation ratio in the revenue and expense of Seaway, in accordance with the partnership agreement. From June 2002 through May 2006, we receive 60% of revenue and expense of Seaway. Thereafter, we will receive 40% of revenue and expense of Seaway. On a pro-rated basis, our share of revenue and expense of Seaway will decrease to approximately 47% for 2006.

We expect to expand the Jonah system with a service date for such expansion being late 2006. We expect to enter into a joint venture agreement with an affiliate of Enterprise Products Partners L.P. (“Enterprise”) relating to the construction and financing of the expansion. Enterprise will be responsible for all activities relating to the construction of the Jonah Expansion and will advance all amounts necessary to plan, engineer, construct or complete the Jonah Expansion (anticipated to be approximately $200.0 million). Such advance will constitute a Subscription for an equity interest in the proposed Joint Venture. We have the option to return to Enterprise up to 100% of the amount of the Subscription. If we return a portion of the Subscription to Enterprise, our relative interests in the proposed Joint Venture will be adjusted accordingly. The proposed Joint Venture will terminate without liability to either party if we return 100% of the Subscription.

Consistent with our business strategy, we continuously evaluate possible acquisitions of assets that would complement our current operations, including assets which, if acquired, would have a material effect on our financial position, results of operations or cash flows.

Discontinued Operations

The sale of the Pioneer silica gel natural gas processing plant located in Opal, Wyoming to Enterprise was initiated because it is not an integral part of our Midstream Segment operations, and natural gas processing is not a core business. The sales proceeds were used to retire debt and for other general partnership purposes. Sales of petroleum products of the Midstream Segment, generated from the processing arrangements at the Jonah Pioneer plant less purchases of gas will be reduced in 2006 as a result of the sale of the Pioneer plant. The operations of the Pioneer plant are reflected as discontinued operations in our consolidated financial statements as of and for the years ended December 31, 2005 and 2004. The Pioneer plant was constructed as part of the Phase III expansion of the Jonah system and was completed during the first quarter of 2004.

Restatement of Consolidated Financial Statements

We are restating our previously reported consolidated financial statements for the fiscal years ended December 31, 2003 and 2004. For the impact of the restated consolidated financial results for the quarterly periods during the years ended December 31, 2005 and 2004, see Note 20 in the Notes to the Consolidated Financial Statements. We have determined that our method of accounting for the $33.4 million excess investment in Centennial, previously described as an intangible asset with an indefinite life, and the $27.1 million excess investment in Seaway, previously described as equity method goodwill, was incorrect. Through our accounting for these excess investments in Centennial and Seaway as intangible assets with indefinite lives and equity method goodwill, respectively, we have been testing the amounts for impairment on an annual basis as opposed to amortizing them over a determinable life. We determined that it would be more appropriate to account for these excess investments as intangible assets with determinable lives. As a result, we made non-cash adjustments that reduced the net value of the excess investments in Centennial and Seaway, and increased amortization expense allocated to our equity earnings. The effect of this restatement caused a $3.8 million and $4.0 million reduction to net income as previously reported for the fiscal years ended December 31, 2004 and 2003, respectively. As a result of the accounting correction, net income for the fiscal year ended December 31, 2005, includes a charge of $4.8 million, of which $3.8 million relates to the first nine months. Additionally, partners' capital at December 31, 2002, reflects a $2.5 million reduction representing the cumulative effect of this correction for fiscal years ended December 31, 2000 through 2002.

While we believe the impacts of these non-cash adjustments are not material to any previously issued financial statements, we determined that the cumulative adjustment for these non-cash items was too material to record in the fourth quarter of 2005, and therefore it was most appropriate to restate prior periods' results. These non-cash adjustments had no effect on our operating income, compensation expense, debt balances or ability to meet all requirements related to our debt facilities. The restatement had no impact on total cash flows from operating activities, investing activities or financing activities. All amounts in the accompanying consolidated financial statements have been adjusted for this restatement.

We will continue to amortize the $30.0 million excess investment in Centennial related to a contract using units-of-production methodology over a 10-year life. The remaining $3.4 million related to a pipeline will continue to be amortized on a straight-line basis over 35 years. We will continue to amortize the $27.1 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to a pipeline.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Although we believe that these estimates are reasonable, actual results could differ from these estimates. Significant accounting policies that we employ are presented in the notes to the consolidated financial statements (see Note 2 in the Notes to the Consolidated Financial Statements).

Critical accounting policies are those that are most important to the portrayal of our financial position and results of operations. These policies require management's most difficult, subjective or complex judgments, often employing the use of estimates and assumptions about the effect of matters that are inherently uncertain. Our critical accounting policies pertain to revenue and expense accruals, environmental costs, property, plant and equipment and goodwill and intangible assets.

Revenue and Expense Accruals

We routinely make accruals based on estimates for both revenues and expenses due to the timing of compiling billing information, receiving certain third party information and reconciling our records with those of third parties. The delayed information from third parties includes, among other things, actual volumes of crude oil purchased, transported or sold, adjustments to inventory and invoices for purchases, actual natural gas and NGL

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deliveries and other operating expenses. We make accruals to reflect estimates for these items based on our internal records and information from third parties. Most of the estimated accruals are reversed in the following month when actual information is received from third parties and our internal records have been reconciled.

The most difficult accruals to estimate are power costs, property taxes and crude oil margins. Power cost accruals generally involve a two to three month estimate, and the amount varies primarily for actual power usage. Power costs are dependent upon the actual volumes transported through our pipeline systems and the various power rates charged by numerous power companies along the pipeline system. Peak demand rates, which are difficult to predict, drive the variability of the power costs. For the year ended December 31, 2005, approximately 12% of our power costs were recorded using estimates. A variance of 10% in our aggregate estimate for power costs would have an approximate $0.6 million impact on annual earnings. Property tax accruals involve significant tax rate estimates in numerous jurisdictions. Actual property taxes are often not known until the tax bill is settled in subsequent periods, and the tax amount can vary for tax rate changes and changes in tax methods or elections. A variance of 10% in our aggregate estimate for property taxes could have up to an approximate $1.4 million impact on annual earnings. Crude oil margin estimates are based upon an average of the past twelve months of crude oil marketing volumes, factoring in current market events, and prices of crude oil. We use an average of prices that were in effect during the applicable month to determine the expected revenue amount, and we determine the margin by evaluating the actual margins of the prior twelve months. As of December 31, 2005, approximately 11% of our annual crude oil margin is recorded using estimates. A variance from this estimate of 10% would impact the respective line items by approximately $1.2 million on an annual basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Environmental Costs

At December 31, 2005, we have accrued a liability of $2.4 million for our estimate of the future payments we expect to pay for environmental costs to remediate existing conditions attributable to past operations. Environmental costs include initial site surveys and environmental studies of potentially contaminated sites, costs for remediation and restoration of sites determined to be contaminated and ongoing monitoring costs, as well as damages and other costs, when estimable. We monitor the balance of accrued undiscounted environmental liabilities on a regular basis. We record liabilities for environmental costs at a specific site when our liability for such costs is probable and a reasonable estimate of the associated costs can be made. Adjustments to initial estimates are recorded, from time to time, to reflect changing circumstances and estimates based upon additional information developed in subsequent periods. Estimates of our ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation alternatives available and the evolving nature of environmental laws and regulations. A variance of 10% in our aggregate estimate for environmental costs would have an approximate $0.3 million impact on annual earnings. For information concerning environmental regulation and environmental costs and contingencies, see Items 1 and 2. Business and Properties — Environmental and Safety Matters.

Property, Plant and Equipment

We regularly review long-lived assets for impairment in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Such events or changes include, among other factors: operating losses, unused capacity; market value declines; technological developments resulting in obsolescence; changes in demand for products in a market area; changes in competition and competitive practices; and changes in governmental regulations or actions. Recoverability of the carrying amount of assets to be held and used is measured by a comparison of the carrying amount of the asset to estimated future undiscounted net cash flows expected to be generated by the asset. Estimates of future undiscounted net cash flows include anticipated future revenues, expected future operating costs and other estimates. Such estimates of future undiscounted net cash flows are highly subjective and are based on numerous assumptions about future operations and market conditions. If such assets

are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the estimated fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or estimated fair value less costs to sell.

Goodwill and Intangible Assets

Goodwill and intangible assets represent the excess of consideration paid over the estimated fair value of tangible net assets acquired. Certain assumptions and estimates are employed in determining the estimated fair value of assets acquired including goodwill and other intangible assets as well as determining the allocation of goodwill to the appropriate reporting unit. In addition, we assess the recoverability of these intangibles by determining whether the amortization of these intangibles over their remaining useful lives can be recovered through undiscounted estimated future net cash flows of the acquired operations. The amount of impairment, if any, is measured by the amount by which the carrying amounts exceed the projected discounted estimated future operating cash flows.

During 2002, we adopted SFAS No. 142, *Goodwill and Other Intangible Assets*, which discontinues the amortization of goodwill and intangible assets that have indefinite lives and requires an annual test of impairment based on a comparison of the estimated fair value to carrying values. The evaluation of impairment for goodwill and intangible assets with indefinite lives under SFAS 142 requires the use of projections, estimates and assumptions as to the future performance of the operations, including anticipated future revenues, expected future operating costs and the discount factor used. Actual results could differ from projections resulting in revisions to our assumptions and, if required, recognizing an impairment loss. Based on our assessment, we do not believe our goodwill is impaired, and we have not recorded a charge from the adoption of SFAS 142 (see Note 3 in the Notes to the Consolidated Financial Statements). At December 31, 2005, the recorded value of goodwill was $16.9 million.

At December 31, 2005, we have $344.0 million of intangible assets, net of accumulated amortization, related to natural gas transportation contracts which were recorded as part of our acquisitions of Jonah on September 30, 2001, and Val Verde on June 30, 2002. The value assigned to the natural gas transportation contracts required management to make estimates regarding the fair value of the assets acquired. In connection with the acquisition of Jonah, we assumed contracts that dedicate future production from natural gas wells in the Green River Basin in Wyoming. We assigned $222.8 million of the purchase price to these production contracts based upon a fair value appraisal at the time of the acquisition. In connection with the acquisition of Val Verde, we assumed fixed-term gas transportation contracts with customers in the San Juan Basin in New Mexico and Colorado. We assigned $239.6 million of the purchase price to these fixed term contracts based upon a fair value appraisal at the time of the acquisition. The value assigned to intangible assets is amortized on a unit-of-production basis, based upon the actual throughput of the system compared to the expected total throughput for the lives of the contracts. On a quarterly basis, we update throughput estimates and evaluate the remaining expected useful life of the contract assets based upon the best available information. A variance of 10% in our aggregate production estimate for the Jonah and Val Verde systems would have an approximate $7.5 million impact on annual amortization expense. Changes in the estimated remaining production will impact the timing of amortization expense reported for future periods.

At December 31, 2005, we have $43.8 million of excess investments, net of accumulated amortization, in our equity investments in Centennial and Seaway, which are being amortized over periods ranging from 10 to 39 years (see Note 3 in Notes to Consolidated Financial Statements). The value assigned to our excess investment in Centennial was created upon its formation. Approximately $30.0 million is related to a contract and is being amortized on a unit-of-production basis based upon the volumes transported under the contract compared to the guaranteed total throughput of the contract over a 10-year life. The remaining $3.4 million is related to a pipeline and is being amortized on a straight-line basis over the life of the pipeline, which is 35 years. The value assigned to our excess investment in Seaway was created upon acquisition of our 50% ownership interest in 2000. We are amortizing the $27.1 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to the life of the pipeline. A variance of 10% in our amortization expense allocated to equity earnings could have up to an approximate $0.5 million impact on annual earnings.

Results of Operations

The following table summarizes financial information by business segment for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,		
	2005	2004 (as restated)	2003 (as restated)
Operating revenues:			
Downstream Segment	$ 287,191	$ 279,400	$ 266,427
Upstream Segment	8,110,239	5,475,995	3,806,215
Midstream Segment	211,171	195,902	185,105
Intercompany eliminations	(3,567)	(3,207)	(1,915)
Total operating revenues	8,605,034	5,948,090	4,255,832
Operating income:			
Downstream Segment	88,143	71,263	83,704
Upstream Segment	33,174	32,265	28,416
Midstream Segment	98,716	80,916	80,288
Total operating income	220,033	184,444	192,408
Earnings before interest from continuing operations:			
Downstream Segment	85,914	65,506	76,546
Upstream Segment	56,408	61,363	48,980
Midstream Segment	98,940	81,043	80,577
Intercompany eliminations	—	—	(73)
Interest expense	(88,620)	(76,280)	(89,540)
Interest capitalized	6,759	4,227	5,290
Income from continuing operations	159,401	135,859	121,780
Discontinued operations (1)	3,150	2,689	—
Net income	$ 162,551	$ 138,548	$ 121,780

(1) The Pioneer plant is reflected as discontinued operations for the years ended December 31, 2004 and 2005. The Pioneer plant was constructed as part of the Phase III expansion of the Jonah system and was completed during the first quarter of 2004.

Below is a detailed analysis of the results of operations, including reasons for changes in results, by each of our operating segments.

Downstream Segment

The following table provides financial information for the Downstream Segment for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,			Increase (Decrease)	
	2005	2004 (as restated)	2003 (as restated)	2005-2004	2004-2003
Transportation — Refined products	$ 144,552	$ 148,166	$ 138,926	$ (3,614)	$ 9,240
Transportation — LPGs	96,297	87,050	91,787	9,247	(4,737)
Other	46,342	44,184	35,714	2,158	8,470
Total operating revenues	287,191	279,400	266,427	7,791	12,973
Operating, general and administrative	116,187	124,905	113,389	(8,718)	11,516
Operating fuel and power	32,500	31,706	28,806	794	2,900
Depreciation and amortization	39,403	43,135	31,620	(3,732)	11,515

Taxes — other than income taxes	11,097	8,917	8,908	2,180	9
Gains on sales of assets	(139)	(526)	—	387	(526)
Total costs and expenses	199,048	208,137	182,723	(9,089)	25,414
Operating income	88,143	71,263	83,704	16,880	(12,441)
Equity losses	(2,984)	(6,544)	(7,384)	3,560	840
Other income — net	755	787	226	(32)	561
Earnings before interest	$ 85,914	$ 65,506	$ 76,546	$ 20,408	$ (11,040)

The following table presents volumes delivered in barrels and average tariff per barrel for the years ended December 31, 2005, 2004 and 2003 (in thousands, except tariff information):

	Years Ended December 31,			Percentage Increase (Decrease)	
	2005	2004	2003	2005-2004	2004-2003
Volumes Delivered:					
Refined products	160,667	152,437	154,061	5%	(1)%
LPGs	45,061	43,982	42,543	3%	3%
Total	205,728	196,419	196,604	5%	—
Average Tariff per Barrel:					
Refined products (1)	$ 0.90	$ 0.97	$ 0.90	(7)%	8%
LPGs	2.14	1.98	2.16	8%	(8)%
Average system tariff per barrel	$ 1.17	$ 1.20	$ 1.17	(3)%	3%

(1) The 2004 period includes $4.1 million of deferred revenue related to the expiration of two customer transportation agreements, which increased the refined products average tariff for the year ended December 31, 2004, by $0.02 per barrel, or 2%.

Our Downstream Segment's results are dependent in large part on the demand for refined products and LPGs in the markets served by its pipelines. Reductions in that demand adversely affect the pipeline business of the Downstream Segment. Market demand varies based upon the different end uses of the products shipped in the Downstream Segment. Demand for gasoline, which in recent years has accounted for approximately forty percent of the Downstream Segment's refined products transportation revenues, depends upon price, prevailing economic conditions and demographic changes in the markets served in the Downstream Segment. Demand for distillates is affected by truck and railroad freight, the price of natural gas used by utilities, which use distillates as a substitute for natural gas when the price of natural gas is high, and usage for agricultural operations, which is affected by weather conditions, government policy and crop prices. Demand for jet fuel, which in recent years has accounted for approximately twenty percent of the Downstream Segment's refined products revenues, depends on prevailing economic conditions and military usage. Propane deliveries are generally sensitive to the weather and meaningful year-to-year variances have occurred in the past and will likely continue to occur in the future.

Year Ended December 31, 2005 Compared with Year Ended December 31, 2004

Revenues from refined products transportation decreased $3.6 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Revenues from refined products transportation decreased primarily due to the recognition of $4.1 million of deferred revenue in 2004 related to the expiration of two customer transportation agreements. Under some of our transportation agreements with customers, the contracts specify minimum payments for transportation services. If the transportation services paid for are not used, the unused transportation service is recorded as deferred revenue. The contracts generally specify a subsequent period of time in which the customer can transport excess products to recover the amount recorded as deferred revenue. During the third quarter of 2004, the time limit under two transportation agreements expired without the customers recovering the unused transportation services. As a result, we recognized the deferred revenue as refined products revenue in that period.

Additionally, refined products revenues decreased due to reduced deliveries of product as a result of Hurricanes Katrina and Rita in August and September 2005, as discussed below. These decreases in revenues from refined products transportation resulting from the hurricanes were partially offset by an overall increase in the refined products volumes delivered primarily due to deliveries of products moved on Centennial. Volume increases were due to increased demand and market share for products supplied from the U.S. Gulf Coast into Midwest markets. The refined products average rate per barrel decreased from the prior year period primarily due to the impact of greater growth in the volume of products delivered under a Centennial tariff compared with the growth in deliveries under a TEPPCO tariff, which resulted in an increased proportion of lower tariff barrels transported on our system. In February 2003, we entered into a lease agreement with Centennial that increased our flexibility to deliver refined products to our market areas. Volumes transported on Centennial increased due to increased demand and market share for products supplied from the U.S. Gulf Coast into Midwest markets. Centennial has provided our system with additional pipeline capacity for products originating in the U.S. Gulf Coast area. Prior to the construction of Centennial, deliveries on our pipeline system were limited by our pipeline capacity, and transportation services for our customers were allocated in accordance with a proration policy. With this incremental pipeline capacity, our previously constrained system has expanded deliveries in markets both south and north of Creal Springs, Illinois.

Revenues from LPGs transportation increased $9.3 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, due to higher deliveries of propane in the upper Midwest and Northeast market areas due to system expansion projects completed in 2004 and colder winter weather in March and December 2005. Prior year LPG transportation revenues were negatively impacted by a price spike in the Mont Belvieu propane price in late February 2004, which resulted in TEPPCO sourced propane being less competitive than propane from other source points. The LPGs average rate per barrel increased from the prior period primarily as a result of a combination of decreased short-haul deliveries and increased long-haul propane deliveries during 2005, and an increase in tariff rates which went into effect in July 2005. These increases were partially offset by reduced propane revenues resulting from decreased propane deliveries due to a propane release and fire at a dehydration unit in September 2005 at our Todhunter storage facility, near Middletown, Ohio. As a result of the propane release and fire, our LPG loading facilities at Todhunter were shut down for approximately three weeks.

Revenues from refined products and LPGs were also impacted by Hurricanes Katrina and Rita, which affected the U.S. Gulf Coast in August and September 2005, respectively. Hurricane Katrina disrupted refineries and other pipeline systems in the central U.S. Gulf Coast, which provided us with additional deliveries at Shreveport and Arcadia, Louisiana, as shippers used alternative sources to supply product to areas where normal distribution patterns were disrupted. Hurricane Katrina also resulted in higher prices of refined products and LPGs, which had a negative impact on the current demand for the products. Hurricane Rita disrupted production at western U.S. Gulf Coast refineries, many of which directly supply us with product. Hurricane Rita also disrupted power to our Beaumont terminal, which resulted in the mainline being shut down for four days and Centennial being shut down for ten days. Our 230,000 barrel per day capacity, 20-inch diameter mainline system, which primarily delivers LPGs and gasoline from the Texas Gulf Coast to the Midwest, was pumping from MB Storage's facility at approximately 60% of normal operating capacity until mid-October. Our 110,000 barrel per day capacity, 14-inch and 16-inch diameter pipelines, which primarily deliver distillates and gasoline from the Texas Gulf Coast to the Midwest, were pumping at approximately 75% of normal operating capacity from our Baytown, Texas, terminal until mid-October. We installed generators at our Beaumont, Texas, facility, which enabled receipt and delivery of

refined products out of tankage at the terminal. Commercial power was restored to the Beaumont terminal and the Newton, Texas, pump station in mid-October and full operations were resumed. Centennial resumed operating at its normal capacity on October 1, 2005.

Other operating revenues increased $2.2 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, primarily due to higher refined products tender deduction, additive and loading fees, partially offset by lower propane inventory fees in 2005. Lower volumes of product inventory sales in the 2005 period were partially offset by increased sales margin on the product inventory sales.

Costs and expenses decreased $9.0 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, due to decreased operating, general and administrative expenses and decreased depreciation and amortization expense, partially offset by increased taxes — other than income taxes, increased operating fuel and power and lower gains on the sales of assets in the 2005 period. Operating, general and administrative expenses decreased $8.7 million primarily due to the following:

- a $15.1 million decrease in pipeline inspection and repair costs associated with our integrity management program as we neared completion of the first cycle of our integrity management program,
- a $2.6 million decrease in postretirement benefit accruals related to plan amendments (see Note 15 in the Notes to the Consolidated Financial Statements),
- a $2.1 million decrease in products losses,
- a $2.0 million decrease in legal expenses related to a legal settlement in 2004 (see Note 16 in the Notes to the Consolidated Financial Statements) and
- a $1.1 million decrease in consulting services primarily related to acquisition related activities in the 2004 period.

These decreases to costs and expenses were partially offset by the following:

- a $3.4 million increase in labor and benefits expenses primarily associated with vesting provisions in certain of our compensation plans as a result of changes in ownership of our General Partner, higher labor expenses associated with an increase in the number of employees between years and higher incentive compensation expense as a result of improved operating performance,
- a $3.4 million increase in pipeline operating and maintenance expense,
- a $1.8 million increase attributable to regulatory penalties for past incidents,
- a $1.6 million increase in insurance expense,
- a $1.5 million increase related to transition costs due to the changes in ownership of our General Partner,
- a $0.6 million increase in rental expense on a lease agreement from the Centennial pipeline capacity lease agreement and
- an increase in other miscellaneous general and administrative supplies expenses during the year, including a $0.4 million increase in environmental assessment and remediation expenses, a $0.4 million increase in labor and benefits expense related to retirement plan settlements with DEFS and hurricane related expenses.

Depreciation expense decreased $3.7 million primarily due to a $4.4 million non-cash impairment charge in the third quarter of 2004, partially offset by a $0.8 million write-off of assets related to the propane release and fire at a storage facility in Ohio (see Note 9 in the Notes to the Consolidated Financial Statements), assets placed into service and assets retired to depreciation expense in the 2005 period. Taxes — other than income taxes increased $2.2 million primarily due to asset acquisitions and a higher tax base in the 2005 period. Operating fuel and power expense increased $0.8 million primarily as a result of increased volumes and higher power rates during the 2005 period. During the year ended December 31, 2004, we recognized net gains of $0.5 million from the sales of various assets in the Downstream Segment.

Net losses from equity investments decreased $3.6 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, as shown below (in thousands):

	Years Ended December 31, 2005	Years Ended December 31, 2004 (as restated)	Increase (Decrease)
Centennial	$ (10,727)	$ (14,379)	$ 3,652
MB Storage	7,715	7,874	(159)
Other	28	(39)	67
Total equity losses	$ (2,984)	$ (6,544)	$ 3,560

Equity losses in Centennial decreased $3.7 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, primarily due to higher transportation revenues and volumes.

Equity earnings in MB Storage decreased $0.2 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, primarily due to increased depreciation and amortization expense and higher general and administrative expenses, partially offset by higher rental and storage revenues and volumes. MB Storage was impacted by Hurricane Rita, which reduced revenues and increased operating expenses. Additionally, in April 2004, MB Storage acquired storage and pipeline assets and contracts for approximately $35.0 million, of which TE Products contributed $16.5 million. Increases in storage revenue, shuttle revenue, rental revenue and depreciation and amortization expense for year ended December 31, 2005, compared with the year ended December 31, 2004, are primarily related to the acquired storage assets and contracts.

For the year ended December 31, 2005, TE Products received the first $1.7 million per quarter (or $6.78 million on an annual basis) of MB Storage's income before depreciation expense, as defined in the operating agreement. For the year ended December 31, 2004, TE Products received the first $1.8 million per quarter (or $7.15 million on an annual basis) of MB Storage's income before depreciation expense. TE Products' share of MB Storage's earnings is adjusted annually by the partners of MB Storage. Any amount of MB Storage's annual income before depreciation expense in excess of $6.78 million for 2005 and $7.15 million for 2004 is allocated evenly between TE Products and Louis Dreyfus. Depreciation expense on assets each party originally contributed to MB Storage is allocated between TE Products and Louis Dreyfus based on the net book value of the assets contributed. Depreciation expense on assets constructed or acquired by MB Storage subsequent to formation is allocated evenly between TE Products and Louis Dreyfus. For the years ended December 31, 2005, 2004 and 2003, TE Products' sharing ratio in the earnings of MB Storage was approximately 64.2%, 69.4% and 70.4%, respectively.

Year Ended December 31, 2004 Compared with Year Ended December 31, 2003

Revenues from refined products transportation increased $9.2 million for the year ended December 31, 2004, compared with the year ended December 31, 2003. Refined products transportation revenues increased primarily due to higher market-based tariff rates which went into effect in July 2003 and May 2004 and a shift in the distribution of product moved by us to favor longer haul, higher tariff movements. These changes resulted in a 5% increase in the refined products average rate per barrel from the prior year and offset the effect of a 1% decrease in refined products delivery volumes. In February 2003, we entered into a lease agreement with Centennial that increased our flexibility to deliver refined products to our market areas. Volumes transported on Centennial increased due to increased demand and market share for products supplied from the U.S. Gulf Coast into Midwest markets. Refined products transportation revenues also increased due to the recognition of $4.1 million of deferred revenue in the 2004 period related to the expiration of two customer transportation agreements.

Revenues from LPGs transportation decreased $4.7 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to lower deliveries of propane in the upper Midwest and Northeast market areas attributable to warmer weather during the first and fourth quarters of 2004. Additionally, in late February 2004, the Mont Belvieu propane price spiked, which resulted in TEPPCO sourced propane being less competitive than propane from other source points. Also contributing to the decrease were less favorable price differentials between Mont Belvieu and other supply centers during the second and third quarters of 2004. High

propane prices in 2004 also reduced the summer and early fall fill of consumer storage of propane during 2004. These decreases were partially offset by increased deliveries of isobutane to Chicago area refineries and increased short-haul propane deliveries to U.S. Gulf Coast petrochemical customers. The LPGs average rate per barrel decreased 8% from the prior year period primarily as a result of increased short-haul deliveries during 2004.

Other operating revenues increased $8.5 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, primarily due to higher propane inventory fees, higher margins on product inventory sales, higher revenue from our Providence, Rhode Island import facility and higher refined products tender deduction, loading and custody transfer revenues.

Costs and expenses increased $25.4 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to increased operating, general and administrative expenses, increased depreciation and amortization expense and increased operating fuel and power, partially offset by net gains on the sales of assets. Operating, general and administrative expenses increased primarily due to a $6.2 million increase in pipeline inspection and repair costs associated with our integrity management program, a $2.0 million increase in legal accruals related to the settlement of a lawsuit (see Note 16 in the Notes to the Consolidated Financial Statements), a $1.5 million increase in rental expense from the Centennial pipeline capacity lease agreement that we entered into in February 2003, a $1.3 million increase in consulting and contract services related to compliance with the Sarbanes-Oxley Act of 2002 and a $1.1 million increase in costs related to unsuccessful acquisition evaluations. These increases were partially offset by $0.8 million of lower expenses in the 2004 period associated with the write-off of receivables related to customer bankruptcies and non-payments in 2003. Depreciation expense increased from the prior year period because of a $4.4 million charge resulting from the impairment of marine assets in the Beaumont area (see Note 9 in the Notes to the Consolidated Financial Statements). In addition, we wrote off approximately $2.1 million in assets taken out of service during the period to depreciation expense. Depreciation expense also increased approximately $5.0 million as a result of assets placed in service during 2003 and 2004, partially offset by an increase in the estimated remaining life of a section of our pipeline system in the Northeast, resulting from pipeline capital improvements made as part of our integrity management program. Operating fuel and power expense increased primarily as a result of higher power rates during the 2004 period. In addition, we recognized net gains of $0.5 million during 2004 from the sales of various assets in the Downstream Segment.

Net losses from equity investments decreased $0.8 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, as shown below (in thousands):

	Years Ended December 31, 2004 (as restated)	Years Ended December 31, 2003 (as restated)	Increase
Centennial	$ (14,379)	$ (14,671)	$ 292
MB Storage	7,874	7,354	520
Other	(39)	(67)	28
Total equity losses	$ (6,544)	$ (7,384)	$ 840

Equity losses in Centennial decreased $0.3 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, primarily due to increased transportation revenues and volumes and lower operating expenses. During 2003, we acquired an additional 16.7% interest in Centennial on February 10, 2003, bringing TE Products' ownership interest to 50%. Included in the equity loss for the year ended December 31, 2004, is $1.2 million of equity income relating to the settlement of certain transmix matters recognized in previous periods.

Equity earnings in MB Storage increased $0.5 million for the year ended December 31, 2004, compared with the year ended December 31, 2003. In April 2004, MB Storage acquired storage and pipeline assets and contracts for approximately $35.0 million, of which TE Products contributed $16.5 million. The increase in equity earnings is due to increased storage revenue, shuttle revenue and rental revenue primarily from the acquired contracts and lower pipeline rehabilitation expenses on the MB Storage system, partially offset by increased amortization and depreciation expense on storage assets and contracts acquired.

Other income — net increased $0.6 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, primarily due to higher interest income earned on cash investments and higher interest income earned on a capital lease.

Upstream Segment

The following table provides financial information for the Upstream Segment for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,			Increase (Decrease)	
	2005	2004 (as restated)	2003 (as restated)	2005-2004	2004-2003
Sales of petroleum products	$ 8,062,131	$ 5,426,832	$ 3,766,651	$ 2,635,299	$ 1,660,181
Transportation — Crude oil	37,614	37,177	29,057	437	8,120
Other	10,494	11,986	10,507	(1,492)	1,479
Total operating revenues	8,110,239	5,475,995	3,806,215	2,634,244	1,669,780
Purchases of petroleum products	7,989,682	5,370,234	3,713,122	2,619,448	1,657,112
Operating, general and administrative	59,885	51,424	50,471	8,461	953
Operating fuel and power	5,122	5,490	3,672	(368)	1,818
Depreciation and amortization	17,161	13,130	11,311	4,031	1,819
Taxes — other than income taxes	5,333	3,979	3,171	1,354	808
Gains on sales of assets	(118)	(527)	(3,948)	409	3,421
Total costs and expenses	8,077,065	5,443,730	3,777,799	2,633,335	1,665,931
Operating income	33,174	32,265	28,416	909	3,849
Equity earnings	23,078	28,692	20,258	(5,614)	8,434
Other income — net	156	406	306	(250)	100
Earnings before interest	$ 56,408	$ 61,363	$ 48,980	$ (4,955)	$ 12,383

Information presented in the following table includes the margin of the Upstream Segment, which may be viewed as a non-GAAP (Generally Accepted Accounting Principles) financial measure under the rules of the SEC. We calculate the margin of the Upstream Segment as revenues generated from the sale of crude oil and lubrication oil, and transportation of crude oil, less the costs of purchases of crude oil and lubrication oil. We believe that margin is a more meaningful measure of financial performance than sales and purchases of crude oil and lubrication oil due to the significant fluctuations in sales and purchases caused by variations in the level of volumes marketed and prices for products marketed. Additionally, we use margin internally to evaluate the financial performance of the Upstream Segment as we believe margin is a better indicator of performance than operating income as operating, general and administrative expenses, operating fuel and power and depreciation expense are not directly related to the margin activities. Margin and volume information for the years ended December 31, 2005, 2004 and 2003 is presented below (in thousands, except per barrel and per gallon amounts):

	Years Ended December 31,			Percentage Increase (Decrease)	
	2005	2004	2003	2005-2004	2004-2003
Margins: (1)					
Crude oil transportation	$ 61,611	$ 55,425	$ 45,794	11%	21%
Crude oil marketing	30,597	22,468	22,017	36%	2%
Crude oil terminaling	10,400	9,388	9,403	11%	—
Lubrication oil sales	7,455	6,494	5,372	15%	21%
Total margin	$ 110,063	$ 93,775	$ 82,586	17%	14%
Total barrels:					
Crude oil transportation	94,743	101,462	95,541	(7)%	6%
Crude oil marketing	203,325	177,273	159,710	15%	11%
Crude oil terminaling	110,254	113,197	115,076	(3)%	(2)%

Lubrication oil volume (total gallons)	14,844	13,964	10,449	6%	34%
Margin per barrel:					
Crude oil transportation	$ 0.650	$ 0.546	$ 0.479	19%	14%
Crude oil marketing	0.150	0.127	0.138	19%	(8)%
Crude oil terminaling	0.094	0.083	0.082	14%	1%
Lubrication oil margin (per gallon):	$ 0.502	$ 0.465	$ 0.514	8%	(10)%

(1) Margins in this table are presented prior to the elimination of intercompany sales, revenues and purchases between TCO and TCPL.

The following table reconciles the Upstream Segment margin to operating income in the consolidated statements of income using the information presented in the tables above, in the consolidated statements of income and in the statements of income in Note 17 in the Notes to the Consolidated Financial Statements (in thousands):

	Years Ended December 31,		
	2005	2004 (as restated)	2003 (as restated)
Sales of petroleum products	$ 8,062,131	$ 5,426,832	$ 3,766,651
Transportation — Crude oil	37,614	37,177	29,057
Less: Purchases of petroleum products	(7,989,682)	(5,370,234)	(3,713,122)
Total margin	110,063	93,775	82,586
Other operating revenues	10,494	11,986	10,507
Total operating revenues	120,557	105,761	93,093
Operating, general and administrative	59,885	51,424	50,471
Operating fuel and power	5,122	5,490	3,672
Depreciation and amortization	17,161	13,130	11,311
Taxes — other than income taxes	5,333	3,979	3,171
Gains on sales of assets	(118)	(527)	(3,948)
Operating income	$ 33,174	$ 32,265	$ 28,416

Year Ended December 31, 2005 Compared with Year Ended December 31, 2004

Our margin increased $16.3 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Crude oil marketing margin increased $8.1 million primarily due to increased volumes marketed primarily due to asset acquisitions, partially offset by increased transportation costs. Crude oil transportation margin increased $6.2 million primarily due to increased transportation volumes and revenues on our South Texas system due to the acquisition of crude oil pipeline assets in April 2005 and higher revenues on our West Texas systems resulting from organic growth projects on the systems and benefits realized from assets acquired at Cushing. The average margin per barrel increased 22% primarily due to movements of volumes on

higher tariff segments, including higher tariffs on the assets acquired from BP in April 2005. Lubrication oil sales margin increased $1.0 million due to increased sales of lubrication oils and chemicals and the acquisitions of lubrication oil distributors in Casper, Wyoming, in August 2004, and in Dumas, Texas, in August 2005. Crude oil terminaling margin increased $1.0 million as a result of increased pumpover volumes at Cushing, Oklahoma, partially offset by decreased pumpover volumes at Midland, Texas.

Other operating revenues decreased $1.5 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, primarily due to a $1.4 million favorable settlement of inventory imbalances in the first quarter of 2004 and lower revenues from documentation and other services to support customers' trading activity at Midland and Cushing in 2005.

Costs and expenses, excluding expenses associated with purchases of crude oil and lubrication oil, increased $13.9 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, due to increased operating, general and administrative expenses, increased depreciation and amortization expense, increased taxes — other than income taxes and lower gains on sales of assets in the 2005 period, partially offset by decreased operating fuel and power. Operating, general and administrative expenses increased $8.5 million from the prior year period as a result of the following:

- a $4.8 million increase in pipeline operating and maintenance expense primarily due to acquisitions and the continued integration of the Genesis assets into our system,
- a $2.7 million increase in labor and benefits expense related to vesting provisions in certain of our compensation plans as a result of changes in ownership of our General Partner, an increase in the number of employees between periods, and higher incentive compensation expense as a result of improved operating performance,
- a $1.0 million settlement of an indemnity related to a past acquisition,
- a $0.7 million increase in transition charges as a result of changes in ownership of our General Partner,
- a $0.7 million increase in bad debt expense primarily related to a customer nonpayment,
- a $0.4 million increase in operating costs for our undivided ownership interest in Basin Pipeline,
- a $0.3 million increase related to a legal settlement and
- increases in miscellaneous administrative supplies and expenses.

These increases were partially offset by a $2.3 million decrease in product measurement losses, a $1.9 million decrease in pipeline inspection and repair costs associated with our integrity management program and a $1.2 million decrease in environmental assessment and remediation costs. Depreciation and amortization expense increased $4.0 million primarily as a result of a $2.6 million non-cash impairment charge in the third quarter of 2005, resulting from the impairment of two crude oil systems (see Note 9 in the Notes to the Consolidated Financial Statements). Depreciation expense also increased as a result of assets placed in service and assets retired to depreciation expense during the period. Taxes — other than income taxes increased $1.4 million due to asset acquisitions and a higher asset base in the 2005 period. During the year ended December 31, 2004, we recognized a gain of $0.4 million from the sale of our remaining interest in the original Rancho Pipeline system (see Note 5 in the Notes to the Consolidated Financial Statements). Operating fuel and power decreased $0.4 million primarily as a result of lower transportation volumes in 2005.

Equity earnings from our investment in Seaway decreased $5.6 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, primarily due to higher operating, general and administrative expenses related to a pipeline release in May 2005 discussed below, higher power costs, decreased gains on inventory sales, higher depreciation expense and a favorable settlement in the first quarter of 2004 with a former owner of Seaway's crude oil assets regarding inventory imbalances that were not acquired by us, partially offset by higher long-haul transportation volumes.

After Seaway's pipeline release in May 2005, the maximum operating pressure on the pipeline system was reduced by 20% until the cause of the failure is determined and any required corrective measures are implemented. A study of the failed pipe was performed by independent, metallurgical experts who determined that the pipe failed due to damage that occurred during rail shipment associated with its installation thirty years ago. The corrective actions include running a very sophisticated, high definition inspection tool through the pipe to determine if there

are any other sections of pipe that have similar damage. This approach is consistent with directives from the United States Department of Transportation's Office of Pipeline Safety in past failures of this type. The inspection tool has been run and the resulting data is currently being analyzed. We expect Seaway to be operating at reduced maximum pressures through the second quarter of 2006. As a result of operating at reduced maximum pressures, during the third quarter of 2005, we began using a drag reducing agent to increase the flow of product through the pipeline system. The drag reducing agent allowed us to maintain the higher volumes transported, but also increased our operating costs. At this time, we do not believe the reduced pressures will have a material adverse effect on our financial position, results of operations or cash flows.

Year Ended December 31, 2004 Compared with Year Ended December 31, 2003

Our margin increased $11.2 million for the year ended December 31, 2004, compared with the year ended December 31, 2003. Crude oil transportation margin increased $9.6 million primarily due to an increase in transportation volumes and revenues on our South Texas and Red River systems. Our Basin system also had increased transportation volumes and revenues primarily due to the expansion of the system between Midland, Texas, and Wichita Falls, Texas, resulting in an additional capacity of ten thousand barrels per day on the system, and movements of barrels on higher tariff segments. During the fourth quarter of 2003, we completed the purchase of crude supply and transportation assets (Genesis), which have been integrated into our South Texas system (see Note 5 in the Notes to the Consolidated Financial Statements). Lubrication oil sales margin increased $1.1 million due to increased sales of chemical volumes and increased volumes related to the acquisitions of lubrication oil distributors in Abilene, Texas, in December 2003 and in Casper, Wyoming, in August 2004. Crude oil marketing margin increased $0.5 million as a result of increased volumes marketed, partially offset by an unfavorable invoicing settlement on a marketing contract in the first quarter of 2003, which reduced the marketing margin in 2003, and increased transportation costs. Crude oil terminaling margin remained unchanged as a result of higher pumpover volumes at Cushing, Oklahoma, offset by lower pumpover volumes at Midland, Texas.

Other operating revenues of the Upstream Segment increased $1.5 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, primarily due to a $1.4 million favorable settlement of inventory imbalances, and higher revenues from documentation and other services to support customers' trading activity at Midland and Cushing.

Costs and expenses, excluding expenses associated with purchases of crude oil and lubrication oil, increased $5.4 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to increased operating fuel and power, increased depreciation and amortization expense, increased operating, general and administrative expenses and increased taxes — other than income taxes. Operating fuel and power increased $1.8 million primarily as a result of the acquisition of the Genesis assets and higher volumes in 2004. Depreciation and amortization expense increased $1.8 million primarily due to the assets acquired from Genesis. Operating, general and administrative expenses increased $1.0 million from the prior year primarily due to a $3.9 million increase in pipeline inspection and repair costs associated with our integrity management program, a $2.0 million increase in expenses related to the Genesis acquisition, a $1.4 million increase in labor and benefits expense related to incentive compensation plans and an increase in the number of employees between periods, a $0.7 million increase in consulting and contract services related to compliance with the Sarbanes-Oxley Act of 2002 and a $0.6 million increase in rental expense due to our pipeline lease at Freeport, Texas, with Seaway. These increases were partially offset by $3.8 million of higher environmental assessment and remediation costs in 2003, $1.7 million of expense in 2003 from the net settlement of crude oil imbalances with customers, $1.5 million of higher legal costs in 2003 related to the litigation and settlement with D.R.D. Environmental Services, Inc. and $0.5 million of lower expenses in 2004 from the sale of the Rancho assets in 2003. Taxes — other than income taxes increased $0.8 million due to increases in property tax accruals.

In June 2003, we recorded a net gain of $3.9 million, included in the gain on sale of assets in our consolidated statements of income, on the sale of certain of the assets of the Rancho Pipeline. During the year ended December 31, 2004, we recorded net gains of $0.5 million, included in the gains on sales of assets in our consolidated statements of income, primarily related to the sale of our remaining interest in the original Rancho Pipeline system (see Note 5 in the Notes to the Consolidated Financial Statements).

Equity earnings from our investment in Seaway increased $8.4 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to higher transportation volumes, gains on crude oil inventory sales, a settlement with a former owner of Seaway's crude oil assets regarding inventory imbalances that were not acquired by us and lower operating, general and administrative expenses.

Midstream Segment

The following discussion reflects the recasting as discontinued operations of the Pioneer plant operations. The following table provides financial information for the Midstream Segment for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,			Increase (Decrease)	
	2005	2004	2003	2005-2004	2004-2003
Sales of petroleum products	$ —	$ —	$ —	$ —	$ —
Gathering — Natural gas	152,797	140,122	135,144	12,675	4,978
Transportation — NGLs	43,915	41,204	39,837	2,711	1,367
Other	14,459	14,576	10,124	(117)	4,452
Total operating revenues	211,171	195,902	185,105	15,269	10,797
Purchases of petroleum products	—	—	—	—	—
Operating, general and administrative	43,171	43,580	34,618	(409)	8,962
Operating fuel and power	11,350	10,943	8,884	407	2,059
Depreciation and amortization	54,165	56,019	57,797	(1,854)	(1,778)
Taxes — other than income taxes	4,180	4,444	3,518	(264)	926
Gains on sales of assets	(411)	—	—	(411)	—
Total costs and expenses	112,455	114,986	104,817	(2,531)	10,169
Operating income	98,716	80,916	80,288	17,800	628
Other income — net	224	127	289	97	(162)
Earnings before interest from continuing operations	98,940	81,043	80,577	17,897	466
Income from discontinued operations	3,150	2,689	—	461	2,689
Earnings before interest	$ 102,090	$ 83,732	$ 80,577	$ 18,358	$ 3,155

The following table presents volume and average rate information for the years ended December 31, 2005, 2004 and 2003 (in thousands, except average fee and average rate amounts):

	Years Ended December 31,			Percentage	
	2005	2004	2003	2005-2004	2004-2003
Gathering — Natural Gas — Jonah:					
Million cubic feet (“MMcf”)	415,181	354,546	302,951	17%	17%
Billion British thermal units (“MMmbtu”)	458,159	392,154	336,032	17%	17%
Average fee per Million British thermal unit (“MMBtu”)	$ 0.188	$ 0.194	$ 0.193	(3)%	1%
Gathering — Natural Gas — Val Verde:					
MMcf	180,699	144,539	158,286	25%	(9)%
MMmbtu	159,398	122,706	133,094	30%	(8)%
Average fee per MMBtu	$ 0.418	$ 0.523	$ 0.529	(20)%	(1)%
Transportation — NGLs:					
Thousand barrels	61,051	59,549	57,902	3%	3%
Average rate per barrel	$ 0.719	$ 0.692	$ 0.688	4%	1%
Fractionation — NGLs:					
Thousand barrels	4,431	4,149	4,131	7%	—
Average rate per barrel	$ 1.747	$ 1.797	$ 1.804	(3)%	—
Sales — Condensate:					
Thousand barrels	62.1	84.4	63.3	(26)%	33%
Average rate per barrel	$ 52.21	$ 37.99	$ 30.25	37%	26%

Year Ended December 31, 2005 Compared with Year Ended December 31, 2004

Revenues from the gathering of natural gas increased $12.7 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Natural gas gathering revenues from the Jonah system increased $10.2 million and volumes gathered increased 60.6 Bcf for the year ended December 31, 2005, primarily due to the expansion of the Jonah system in 2004. Installation of additional capacity of 100 million cubic feet per day was completed during the fourth quarter of 2004. Jonah’s average natural gas gathering rate per MMcf decreased due to higher system wellhead pressures. Natural gas gathering revenues from the Val Verde system increased $2.5 million and volumes gathered increased 36.7 Bcf for the year ended December 31, 2005, primarily due to increased volumes from two new connections made to the Val Verde system in May and December 2004, partially offset by the natural decline of CBM production. Val Verde’s average natural gas gathering rate per MMcf decreased due to contracts entered into relating to the new connections, which have lower rates than the existing Val Verde system’s average rates.

Revenues from the transportation of NGLs increased $2.7 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, primarily due to increased volumes transported on the Chaparral, Panola and Dean Pipelines, partially offset by decreased volumes transported on the Wilcox Pipeline. The increase in the NGL transportation average rate per barrel resulted from a higher average rate per barrel on volumes transported on the Panola Pipeline offset by a lower average rate per barrel on the Chaparral Pipeline.

Other operating revenues decreased $0.1 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Val Verde's other operating revenues increased $0.8 million due to revenues generated as a result of contractual producer minimum fuel levels exceeding actual operating fuel usage during 2005. Val Verde retains a portion of its producers' gas to compensate for fuel used in operations. The actual usage of gas can differ from the amount contractually retained from producers. Value retained from producers or sales generated as a result of efficient fuel usage are recognized as other operating revenues. NGL fractionation revenues

increased $0.3 million as a result of higher volumes. Other operating revenues on Chaparral decreased $1.6 million primarily due to the recognition of deferred revenue related to an inventory settlement in the prior year period.

Costs and expenses decreased $2.5 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, due to decreased depreciation and amortization expense, decreased operating, general and administrative expenses, decreased taxes — other than income taxes and a net gain recorded on the sale of an asset, partially offset by increased operating fuel and power. Amortization expense on the Jonah system decreased $2.6 million primarily due to a $3.9 million decrease related to revisions to the estimated life of intangible assets under the units-of-production method, partially offset by a $1.3 million increase as a result of higher volumes in 2005. Amortization expense on the Val Verde system increased $1.4 million primarily due to a $2.4 million increase related to revisions to the estimated life of intangible assets under the units-of-production method, partially offset by a $1.0 million decrease as a result of lower volumes in 2005 on contracts included in the intangible assets, resulting from the natural decline in CBM production. Depreciation expense decreased $0.7 million primarily due to a $3.1 million decrease on Jonah as a result of increases to the estimated lives of Jonah's assets, partially offset by a $1.4 million increase on Val Verde as a result of assets placed into service in 2004 and a $1.0 million increase on the NGL pipelines as a result of assets placed into service and adjustments to asset lives.

Operating, general and administrative expenses decreased $0.4 million from the prior year period as a result a $6.0 million decrease in gas settlement expenses, a $1.2 million decrease in a operating expenses primarily related to Val Verde and a $0.5 million decrease in inspection and repair costs associated with our integrity management program. These decreases were partially offset by a $2.1 million increase in labor and benefits expense primarily associated with vesting provisions in certain of our compensation plans and with certain DEFS employees becoming employees of EPCO, a $1.9 million increase in transition expenses as a result of changes in ownership of our General Partner, a $1.5 million increase in insurance expense and increases in various general and administrative supplies and expenses. Taxes — other than income taxes decreased $0.3 million as a result of adjustments to property tax accruals. Operating fuel and power increased $0.4 million compared to the prior year due to adjustments to the fuel and power accrual in the prior year period, partially offset by increased expenses in 2005 related to higher transportation volumes. A net gain of $0.4 million was recognized on the sale of equipment in the current period.

Year Ended December 31, 2004 Compared with Year Ended December 31, 2003

Revenues from the gathering of natural gas increased $5.0 million for the year ended December 31, 2004, compared with the year ended December 31, 2003. Natural gas gathering revenues from the Jonah system increased $11.3 million and volumes gathered increased 51.6 Bcf for the year ended December 31, 2004, due to the expansion of the Jonah system during 2003. The Phase III expansion was substantially completed during the fourth quarter of 2003 and increased system capacity from 880 MMcf/day to 1,180 MMcf/day. The increase in Jonah's revenues was also partially due to higher gathering rates realized due to lower system pressures resulting from the increased capacity provided by the Phase III expansion. Natural gas gathering revenues from the Val Verde system decreased $6.3 million and volumes gathered decreased 13.7 Bcf for the year ended December 31, 2004, primarily due to the natural decline of CBM production and slower than anticipated completion and connection of infill wells, partially offset by increased volumes from two new connections made to the Val Verde system in May and December 2004. Val Verde's average natural gas gathering rate per MMcf decreased due to contracts entered into relating to the new connections, which have lower rates than the existing Val Verde system's average rates.

Revenues from the transportation of NGLs increased $1.4 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, primarily due to increased volumes transported on the Chaparral and Panola Pipelines, partially offset by decreased volumes on the Dean and Wilcox Pipelines. Higher average rates per barrel on volumes transported on the Panola and Wilcox Pipelines were offset by lower average rates per barrel on volumes transported on the Chaparral and Dean Pipelines.

Other operating revenues increased $4.5 million for the year ended December 31, 2004, compared with the year ended December 31, 2003. Jonah's other operating revenues increased $0.9 million primarily due to higher condensate sales. Other operating revenues on Chaparral increased $1.9 million due to the recognition of deferred revenue related to an inventory settlement. Val Verde's operating revenues increased $1.6 million due to revenues

generated as a result of contractual producer minimum fuel levels exceeding actual operating fuel usage during the year ended December 31, 2004.

Costs and expenses increased $10.2 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to increases in operating, general and administrative expense, operating fuel and power and taxes — other than income taxes, partially offset by a decrease in depreciation and amortization expense. Operating, general and administrative expense increased due to a $3.8 million increase in gas settlement expenses, a $3.0 million increase in general and administrative labor expense, a $1.3 million increase in consulting and contract services related to compliance with the Sarbanes-Oxley Act of 2002, a $0.9 million increase related to our integrity management program and a $0.9 million increase related to Jonah's processing plant which began operations in 2004. These increases were partially offset by a $0.6 million decrease in expense related to the sale of our Enron Corp. receivable, which had been fully reserved in 2001, and a $0.4 million decrease in maintenance expenditures at Val Verde. Operating fuel and power increased $2.1 million, primarily due to higher variable power rates and increased NGL volumes transported during times of peak variable power rates. Depreciation expense increased $2.9 million, primarily as a result of assets placed in service in 2003 related to the expansion of the Jonah system and additional well connections on the Val Verde system in 2004. Taxes — other than income taxes increased $0.9 million as a result of higher property balances. Amortization expense decreased $4.7 million primarily due to revisions to the estimated life of Jonah's intangible assets under the units-of-production method, partially offset by a $1.7 million increase as a result of higher volumes in the 2004 period. In second quarter 2003, Jonah's estimated total throughput of the system was adjusted, which resulted in an extension of the expected amortization period from 16 years to 25 years. During the fourth quarter of 2004, additional limited production forecasts were obtained from some of the producers on the Jonah system related to future expansions of the system, and as a result, we again increased our best estimate of future throughput on the Jonah system. This increase in the estimate of future throughput extended the amortization period of Jonah's natural gas gathering contracts (see Note 3 in the Notes to the Consolidated Financial Statements). Amortization expense on the Val Verde system decreased $2.1 million primarily due to lower volumes in the 2004 period, resulting from the natural decline in CBM production.

Other income — net decreased $0.2 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to lower interest income earned on cash investments.

Discontinued Operations

The operations of the Pioneer plant are reflected as discontinued operations in our consolidated financial statements as of and for the years ended December 31, 2005 and 2004. On January 26, 2006, we announced the execution of a letter of intent to sell our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise. On March 31, 2006, we sold the Pioneer plant to an affiliate of Enterprise for $38.0 million in cash. The Pioneer plant, included in our Midstream Segment, was not an integral part of our operations and natural gas processing is not a core business. The Pioneer plant was constructed as part of the Phase III expansion of the Jonah system and was completed during the first quarter of 2004. We have no continuing involvement in the operations or results of this plant. This transaction was reviewed and approved by the Audit and Conflicts Committee of the board of directors of our General Partner and of the general partner of Enterprise, and a fairness opinion was rendered by an independent third-party. The sales proceeds were used to retire debt and for other general partnership purposes.

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the years ended December 31, 2005 and 2004, are presented below (in thousands):

	Years Ended December 31,	
	2005	2004
Sales of petroleum products	$ 10,479	$ 7,295
Other	2,975	2,807
Total operating revenues	13,454	10,102
Purchases of petroleum products	8,870	5,944
Operating, general and administrative	692	738
Depreciation and amortization	612	610
Taxes — other than income taxes	130	121
Total costs and expenses	10,304	7,413
Income from discontinued operations	$ 3,150	$ 2,689

Sales of petroleum products less purchases of petroleum products resulting from the processing activities at the Jonah Pioneer plant increased $0.3 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, primarily due to increased volumes and higher NGL prices. Jonah's Pioneer gas processing plant was completed during the first quarter of 2004, as a part of the Phase III expansion to increase the processing capacity in southwestern Wyoming. Pioneer's processing agreements allowed the producers to elect annually whether to be charged under a fee-based arrangement or a fee plus keep-whole arrangement. Under the fee-based election, Jonah received a fee for its processing services. Under the fee plus keep-whole election, Jonah received a lower fee for its processing services, retained and sold the NGLs extracted during the process and delivered to producers the residue gas equivalent in energy to the natural gas received from the producers. Jonah sold the NGLs it retained and purchased gas to replace the equivalent energy removed in the liquids. For the 2004 and 2005 periods, the producers elected the fee plus keep-whole arrangement.

Interest Expense and Capitalized Interest

Year Ended December 31, 2005 Compared with Year Ended December 31, 2004

Interest expense increased $12.3 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, primarily due to higher outstanding borrowings and higher short term floating interest rates on our revolving credit facility and $2.0 million of expense related to the termination of a treasury lock (see Note 4 in the Notes to the Consolidated Financial Statements). These increases were partially offset by a higher percentage of fixed interest rate debt during the year ended December 31, 2004, that carried a higher rate of interest as compared with floating interest rate debt. The higher percentage of fixed interest rate debt resulted from an interest rate swap that expired in April 2004 (see Note 4 in the Notes to the Consolidated Financial Statements).

Capitalized interest increased $2.5 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, due to interest capitalized on higher construction work-in-progress balances in 2005.

Year Ended December 31, 2004 Compared with Year Ended December 31, 2003

Interest expense decreased $13.3 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to a higher percentage of variable interest rate debt during the year ended December 31, 2004, that carried a lower rate of interest as compared to fixed interest rate debt. The higher percentage of variable interest rate debt resulted from the expiration of an interest rate swap in April 2004 (see Note 4 in the Notes to the Consolidated Financial Statements). The decrease was partially offset by higher balances outstanding on our revolving credit facility in 2004.

Capitalized interest decreased $1.1 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to interest capitalized on higher construction work-in-progress balances in 2003.

Financial Condition and Liquidity

Cash generated from operations, credit facilities and debt and equity offerings are our primary sources of liquidity. At December 31, 2005, and 2004, we had working capital deficits of $38.1 million and $37.8 million, respectively. At December 31, 2005, we had approximately $274.6 million in available borrowing capacity (applying the most restrictive financial covenants) under our revolving credit facility to cover any working capital needs. Cash flows for the years ended December 31, 2005, 2004 and 2003 were as follows (in millions):

	Years Ended December 31,		
	2005	2004 (as restated)	2003 (as restated)
Cash provided by (used in):			
Operating activities	$ 254.5	$ 267.2	$ 242.4
Investing activities	(350.9)	(190.2)	(188.3)
Financing activities	80.1	(90.1)	(55.6)

Operating Activities

Net cash from operating activities for the years ended December 31, 2005, 2004 and 2003, was comprised of the following (in millions):

	Years Ended December 31,		
	2005	2004 (as restated)	2003 (as restated)
Net income	$ 162.6	$ 138.5	$ 121.8
Income from discontinued operations	(3.2)	(2.7)	—
Depreciation and amortization	110.7	112.3	100.7
Earnings in equity investments	(20.1)	(22.1)	(12.9)
Distributions from equity investments	37.1	47.2	28.0
Gains on sales of assets	(0.7)	(1.1)	(3.9)
Non-cash portion of interest expense	1.6	(0.4)	4.8
Cash provided by (used in) working capital and other	(37.3)	(7.8)	3.9
Net cash provided by continuing operating activities	250.7	263.9	242.4
Cash flows from discontinued operations	3.8	3.3	—
Net cash provided by operating activities	$ 254.5	$ 267.2	$ 242.4

Net cash provided by operating activities from continuing operations decreased $13.2 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Cash distributions from equity investments decreased $10.1 million primarily due to Seaway funding its construction of additional storage tanks from its operating cash flows. Cash used for working capital purposes increased $29.4 million for the year ended December 31, 2005, primarily due to the timing of cash disbursements and cash receipts for crude oil inventory. Cash distributions from our equity investments increased $19.2 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to an improved operating performance in Seaway and MB Storage during the year ended December 31, 2004. Cash used for working capital purposes and other operating activities increased $11.8 million for the year ended December 31, 2004, primarily due to the timing of cash disbursements and cash receipts for working capital components. For a discussion of changes in earnings before interest, depreciation and amortization expense, equity earnings, gain on sales of assets by segment and consolidated interest expense — net, see “Results of Operations.”

Net cash from operating activities for the years ended December 31, 2005, 2004 and 2003, included interest payments, net of amounts capitalized, of $82.3 million, $77.5 million and $79.9 million, respectively. Excluding the effects of hedging activities and interest capitalized during the year ended December 31, 2006, we expect interest payments on our fixed rate Senior Notes to be approximately $78.0 million. We expect to pay our interest payments with cash flows from operating activities.

Investing Activities

Cash flows used in investing activities totaled $350.9 million for the year ended December 31, 2005, and were comprised of $220.6 million of capital expenditures, $69.0 million for the acquisition of Downstream Segment assets, $43.2 million for the acquisition of Upstream Segment assets, $14.4 million of cash paid for linefill on assets owned and $4.2 million of cash contributions for TE Products’ ownership interest in MB Storage for capital expenditures, partially offset by $0.5 million in net cash proceeds from an asset sale in our Midstream Segment. Cash flows used in investing activities totaled $190.2 million for the year ended December 31, 2004, and were comprised of $156.7 million of capital expenditures, $1.5 million of cash contributions for TE Products’ ownership interest in Centennial to cover operating needs and capital expenditures, $21.4 million of cash contributions for TE Products’ ownership interest in MB Storage of which $16.5 million was used to acquire storage assets, $3.4 million for the acquisition of assets during the year ended December 31, 2004 and $1.0 million of cash paid for linefill on assets owned, partially offset by $1.2 million in net cash proceeds from the sales of various assets in our Upstream and Downstream Segments. Cash flows used in investing activities for the year ended December 31, 2004, included $7.4 million of cash used in discontinued investing activities related to the construction of the Pioneer plant. Cash flows used in investing activities totaled $188.3 million for the year ended December 31, 2003, and were comprised of $126.7 million of capital expenditures, $22.0 million for the acquisition of assets, $20.0 million for TE Products' acquisition of an additional 16.7% interest in Centennial, $4.0 million of cash contributions for TE Products' ownership interest in Centennial to cover operating needs and capital expenditures, $2.5 million of cash contributions for TE Products' ownership interest in MB Storage for capital expenditures and $3.1 million of cash paid for linefill on assets owned. These uses of cash were partially offset by $3.0 million in net cash proceeds from the Rancho Pipeline transactions and $0.8 million received on matured cash investments. Cash flows used in investing activities for the year ended December 31, 2003, included $13.8 million of cash used in discontinued investing activities related to the construction of the Pioneer plant.

Financing Activities

Cash flows provided by financing activities totaled $80.1 million for the year ended December 31, 2005, and were comprised of $278.8 million of net proceeds received from the issuance of 7.0 million Units in May and June 2005 and $52.9 million in borrowings, net of repayments, on our revolving credit facility, partially offset by $251.1 million of distributions paid to unitholders and $0.5 million of debt issuance costs related to an amendment of our revolving credit facility. Cash flows used in financing activities totaled $90.1 million for the year ended December 31, 2004, and were comprised of $233.1 million of distributions paid to unitholders, partially offset by $143.0 million in borrowings, net of repayments, from our revolving credit facility. Cash flows used in financing activities totaled $55.6 million for the year ended December 31, 2003, and were comprised of $382.0 million in proceeds from revolving credit facilities; $198.6 million from the issuance in January 2003 of our 6.125% Senior Notes due 2013, partially offset by debt issuance costs of $3.4 million; and $287.5 million from the issuance of 9.2 million Units in April and August 2003. These sources of cash for the year ended December 31, 2003, were partially offset by $604.0 million of repayments on our revolving credit facilities, $113.8 million to repurchase and retire all of the 3.9 million outstanding Class B Units, and $202.5 million of distributions paid to unitholders.

We paid cash distributions to our limited partners and general partner, including general partner incentive distributions, of $251.1 million ($2.675 per Unit), $233.1 million ($2.6375 per Unit), and $202.5 million ($2.50 per Unit) during each of the years ended December 31, 2005, 2004 and 2003, respectively. Additionally, on January 13, 2006, we declared a cash distribution of $0.675 per Unit for the quarter ended December 31, 2005. The distribution of $66.9 million was paid on February 7, 2006, to unitholders of record on January 31, 2006 (see Note 11 in the Notes to the Consolidated Financial Statements).

On May 5, 2005, we sold in an underwritten public offering 6.1 million Units at $41.75 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $244.5 million. On June 8, 2005, 865,000 Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering on May 5, 2005. Proceeds from the over-allotment sale, net of underwriting discount, totaled $34.7 million. The proceeds were used to reduce indebtedness under our revolving credit facility, to fund revenue generating and system upgrade capital expenditures and for general partnership purposes.

Other Considerations

Universal Shelf

We have filed with the SEC a universal shelf registration statement that, subject to agreement on terms at the time of use and appropriate supplementation, allows us to issue, in one or more offerings, up to an aggregate of $2.0 billion of equity securities, debt securities or a combination thereof. In the May 2005 equity offering, we issued $279.2 million of equity securities. At December 31, 2005, we had $1.7 billion available under this shelf registration, subject to customary marketing terms and conditions.

Credit Facilities

We have in place an unsecured revolving credit facility for up to $700.0 million ("Revolving Credit Facility"), which may be increased up to a maximum of $850.0 million upon our request, subject to lender approval and the satisfaction of certain other conditions. The Revolving Credit Facility expires on December 13, 2010. Interest is payable at an applicable margin above either the lender's base rate or LIBOR. At December 31, 2005, $405.9 million was outstanding under the facility, and we had $274.6 million of availability under the most restrictive financial covenant. Restrictive covenants in the credit agreement limit our ability to, among other things, incur additional indebtedness, make distributions in excess of Available Cash (see Note 11 in the Notes to the Consolidated Financial Statements), and complete mergers, acquisitions and sales of assets. In addition, the credit agreement requires us to maintain certain financial ratios, which we were in compliance with at December 31, 2005.

Future Capital Needs and Commitments

We estimate that capital expenditures, excluding acquisitions, for 2006 will be approximately $209.7 million (including $6.0 million of capitalized interest). We expect to spend approximately $147.4 million for revenue generating projects. Capital spending on revenue generating projects and facility improvements will include approximately $70.9 million for the expansion of our Downstream Segment facilities. We expect to spend $16.3 million to expand our Upstream Segment pipelines and facilities in West Texas and Oklahoma and approximately $60.2 million to expand our Midstream Segment assets, with further expansions on our Jonah system. We expect to spend approximately $37.8 million to sustain existing operations, including life-cycle replacements for equipment at various facilities and pipeline and tank replacements among all of our business segments. We expect to spend approximately $18.5 million to improve operational efficiencies and reduce costs among all of our business segments. During 2006, TE Products may be required to contribute cash to Centennial to cover capital expenditures, acquisitions or other operating needs and to MB Storage to cover significant capital expenditures or additional acquisitions. We continually review and evaluate potential capital improvements and expansions that would be complementary to our present business operations. These expenditures can vary greatly depending on the magnitude of our transactions. We may finance capital expenditures through internally generated funds, debt or the issuance of additional equity.

The construction of the Jonah Expansion is expected to be completed through a proposed Joint Venture between us and Enterprise, relating to the construction and financing of the Jonah Expansion. Enterprise will be responsible for all activities relating to the construction of the Jonah Expansion and will advance all amounts necessary to plan, engineer, construct or complete the Jonah Expansion (anticipated to be approximately $200.0 million). Such advance will constitute a Subscription for an equity interest in the proposed Joint Venture. We expect the Jonah Expansion to be put into service in late 2006. We have the option to return to Enterprise up to 100% of the amount of the Subscription. If we return a portion of the Subscription to Enterprise, our relative interests in the proposed Joint Venture will be adjusted accordingly. The proposed Joint Venture will terminate without liability to either party if we return 100% of the Subscription.

Liquidity Outlook

We believe that we will continue to have adequate liquidity to fund future recurring operating and investing activities. Our primary cash requirements consist of normal operating expenses, capital expenditures to sustain existing operations and to complete the Jonah Expansion, revenue generating expenditures, interest payments on our Senior Notes and Revolving Credit Facility, distributions to our General Partner and unitholders and acquisitions of

new assets or businesses. Our cash requirements for 2006 are expected to be funded through operating cash flows and our arrangement with Enterprise under the pending Joint Venture agreement related to the Jonah Expansion. Long-term cash requirements for expansion projects, acquisitions and debt repayments are expected to be funded by several sources, including cash flows from operating activities, borrowings under credit facilities, joint ventures and possibly the issuance of additional equity and debt securities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

Off-Balance Sheet Arrangements

We do not rely on off-balance sheet borrowings to fund our acquisitions. We have no off-balance sheet commitments for indebtedness other than the limited guaranty of Centennial debt and the limited guarantee of Centennial catastrophic events as discussed below. In addition, we have entered into various leases covering assets utilized in several areas of our operations.

Centennial entered into credit facilities totaling $150.0 million, and as of December 31, 2005, $150.0 million was outstanding under those credit facilities. TE Products and Marathon have each guaranteed one-half of the repayment of Centennial's outstanding debt balance (plus interest) under a long-term credit agreement, which expires in 2024, and a short-term credit agreement, which expires in 2007. The guarantees arose in order for Centennial to obtain adequate financing, and the proceeds of the credit agreements were used to fund construction and conversion costs of its pipeline system. Prior to the expiration of the long-term credit agreement, TE Products could be relinquished from responsibility under the guarantee should Centennial meet certain financial tests. If Centennial defaults on its outstanding balance, the estimated maximum potential amount of future payments for TE Products and Marathon is $75.0 million each at December 31, 2005.

TE Products, Marathon and Centennial have entered into a limited cash call agreement, which allows each member to contribute cash in lieu of Centennial procuring separate insurance in the event of a third-party liability arising from a catastrophic event. There is an indefinite term for the agreement and each member is to contribute cash in proportion to its ownership interest, up to a maximum of $50.0 million each. As a result of the catastrophic event guarantee, TE Products has recorded a $4.6 million obligation, which represents the present value of the estimated amount that we would have to pay under the guarantee. If a catastrophic event were to occur and we were required to contribute cash to Centennial, contributions exceeding our deductible might be covered by our insurance.

One of our subsidiaries, TCO, has entered into master equipment lease agreements with finance companies for the use of various equipment. We have guaranteed the full and timely payment and performance of TCO's obligations under the agreements. Generally, events of default would trigger our performance under the guarantee. The maximum potential amount of future payments under the guarantee is not estimable, but would include base rental payments for both current and future equipment, stipulated loss payments in the event any equipment is stolen, damaged, or destroyed and any future indemnity payments. We carry insurance coverage that may offset any payments required under the guarantees.

Contractual Obligations

The following table summarizes our debt repayment obligations and material contractual commitments as of December 31, 2005 (in millions):

	Amount of Commitment Expiration Per Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Revolving Credit Facility	$ 405.9	$ —	$ —	$ 405.9	$ —
6.45% Senior Notes due 2008 (1) (2)	180.0	—	180.0	—	—
7.625% Senior Notes due 2012 (2)	500.0	—	—	—	500.0
6.125% Senior Notes due 2013 (2)	200.0	—	—	—	200.0
7.51% Senior Notes due 2028 (1) (2)	210.0	—	—	—	210.0
Interest payments (3)	823.1	97.8	189.9	171.6	363.8
Debt and interest subtotal	2,319.0	97.8	369.9	577.5	1,273.8
Operating leases (4)	83.7	19.5	28.3	14.3	21.6
Capital expenditure obligations (5)	24.5	24.5	—	—	—
Other liabilities and deferred credits (6)	3.7	—	3.2	0.3	0.2
Total	$ 2,430.9	$ 141.8	$ 401.4	$ 592.1	$ 1,295.6

(1) Obligations of TE Products.

(2) Our TE Products subsidiary entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its 7.51% Senior Notes due 2028. At December 31, 2005, the 7.51% Senior Notes include an adjustment to decrease the fair value of the debt by $0.9 million related to this interest rate swap agreement. We also entered into interest rate swap agreements to hedge our exposure to changes in the fair value of our 7.625%

Senior Notes due 2012. At December 31, 2005, the 7.625% Senior Notes include a deferred gain, net of amortization, from previous interest rate swap terminations of $32.4 million. At December 31, 2005, our 6.45% Senior Notes, our 7.625% Senior Notes and our 6.125% Senior Notes include $2.4 million of unamortized debt discounts. The fair value adjustments, the deferred gain adjustment and the unamortized debt discounts are excluded from this table.

(3) Includes interest payments due on our Senior Notes and interest payments and commitment fees due on our Revolving Credit Facility. The interest amount calculated on the Revolving Credit Facility is based on the assumption that the amount outstanding and the interest rate charged both remain at their current levels.

(4) Includes a pipeline capacity lease with Centennial. In January 2003, TE Products entered into a pipeline capacity lease agreement with Centennial for a period of five years that contains a minimum throughput requirement. For the year ended December 31, 2005, TE Products exceeded the minimum throughput requirements on the lease agreement.

(5) Includes accruals for costs incurred but not yet paid relating to capital projects.

(6) Excludes approximately $8.6 million of long-term deferred revenue payments, which are being transferred to income over the term of the respective revenue contracts and $4.6 million related to our estimated amount of obligation under a catastrophic event guarantee for Centennial. The amount of commitment by year is our best estimate of projected payments of these long-term liabilities.

At December 31, 2005, we had an $11.5 million standby letter of credit in connection with crude oil purchases in the fourth quarter of 2005. This amount will be paid during the first quarter of 2006.

We expect to repay the long-term, senior unsecured obligations and bank debt through the issuance of additional long-term senior unsecured debt at the time the 2008, 2012, 2013 and 2028 debt matures, issuance of additional equity, with proceeds from dispositions of assets, cash flow from operations or any combination of the above items.

In addition to the items in the table above, we have entered into various operational commitments and agreements related to pipeline operations and to the marketing, transportation, terminaling and storage of crude oil. The majority of contractual commitments we make for the purchase of crude oil range in term from a thirty-day evergreen to one year. A substantial portion of the contracts for the purchase of crude oil that extend beyond thirty days include cancellation provisions that allow us to cancel the contract with thirty days written notice. During the year ended December 31, 2005, crude oil purchases averaged approximately $665.8 million per month.

Our senior unsecured debt is rated BBB- by Standard and Poors (“S&P”) and Baa3 by Moody’s Investors Service (“Moody’s”). S&P assigned this rating on June 14, 2005, following its review of the ownership structure, corporate governance issues, and proposed funding after the acquisition of the General Partner by DFI. Both ratings are with a stable outlook. A rating reflects only the view of a rating agency and is not a recommendation to buy, sell or hold any indebtedness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that the circumstances warrant such a change. The senior unsecured debt of our subsidiary, TE Products, is also rated BBB- by S&P and Baa3 by Moody’s. Both ratings are with a stable outlook.

Recent Accounting Pronouncements

See discussion of new accounting pronouncements in Note 2 in the Notes to the Consolidated Financial Statements.

Item 8. ***Financial Statements and Supplementary Data***

Our consolidated financial statements, together with the independent registered public accounting firm’s report of KPMG LLP, begin on page F-1 of this Report.

Item 13. ***Certain Relationships and Related Transactions***

Our Management and Relationships with Duke Energy, DEFS and affiliates and EPCO and affiliates

The Partnership does not have any employees. We are managed by the Company, which for all periods prior to February 23, 2005, was an indirect wholly owned subsidiary of DEFS. According to the Partnership Agreement, the Company was entitled to reimbursement of all direct and indirect expenses related to our business activities. As a result of the change in ownership of the General Partner on February 24, 2005, all of our management, administrative and operating functions are performed by employees of EPCO, pursuant to an administrative services agreement. We reimburse EPCO for the costs of its employees who perform operating functions for us and for costs related to its other management and administrative employees (see Note 1 in the Notes to the Consolidated Financial Statements).

The following table summarizes the related party transactions with EPCO and affiliates and DEFS and affiliates for the periods indicated (in millions):

	Years Ended December 31,		
	2005	2004	2003
Revenues from EPCO and affiliates (1)			
Transportation — NGLs (2)	$ 7.4	$ —	$ —

Transportation — LPGs (3)	4.3	—	—
Other operating revenues (4)	0.3	—	—
Costs and Expenses from EPCO and affiliates (1)			
Payroll and administrative (5)	68.2	—	—
Purchases of petroleum products (6)	3.4	—	—
Revenues from DEFS and affiliates (7)			
Sales of petroleum products (8)	4.3	23.2	15.2
Transportation — NGLs (9)	2.8	16.7	17.2
Gathering — Natural gas — Jonah (10)	0.5	3.3	2.0
Transportation — LPGs (11)	0.7	2.6	2.8
Other operating revenues (12)	2.4	14.0	10.8
Costs and Expenses from DEFS and affiliates (7) (13) (14)			
Payroll and administrative (5)	16.2	95.9	88.8
Purchases of petroleum products — TCO (15)	37.7	141.3	110.7
Purchases of petroleum products — Jonah (16)	0.8	5.1	—

(1) Operating revenues earned and expenses incurred from activities with EPCO and its affiliates are considered related party transactions from February 24, 2005, through December 31, 2005, as a result of the change in ownership of the General Partner (see Note 1 in the Notes to the Consolidated Financial Statements).

(2) Includes revenues from NGL transportation on the Chaparral and Panola NGL pipelines.

(3) Includes revenues from LPG transportation on the TE Products pipeline.

(4) Includes other operating revenues on TE Products.

(5) Substantially all of these costs were related to payroll, payroll related expenses and administrative expenses incurred in managing us and our subsidiaries.

(6) Includes TCO purchases of condensate and expenses related to LSI's use of an affiliate of EPCO as a transporter.

(7) Operating revenues earned and expenses incurred from activities with DEFS and its affiliates are considered related party transactions for all periods through February 23, 2005, as a result of the change in ownership of the General Partner (see Note 1 in the Notes to the Consolidated Financial Statements).

(8) Includes LSI sales of lubrication oils and specialty chemicals and Jonah NGL sales in connection with Jonah's Pioneer processing plant operations, which was constructed during the Phase III expansion and began operating in 2004. Amounts related to the Pioneer plant are classified as discontinued operations in the consolidated statements of income.

(9) Includes revenues from NGL transportation on the Chaparral, Panola, Dean and Wilcox NGL pipelines.

(10) Includes gas gathering revenues on the Jonah system.

(11) Effective May 2001, we entered into an agreement with an affiliate of DEFS to commit to it sole utilization of our Providence terminal. We operate the terminal and provide propane loading services to an affiliate of DEFS. We recognized revenue from an affiliate of DEFS pursuant to this agreement.

(12) Includes fractionation revenues and other revenues. Effective with the purchase of the fractionation facilities on March 31, 1998, TEPPCO Colorado and DEFS entered into a 20-year Fractionation Agreement, under which TEPPCO Colorado receives a variable fee for all fractionated volumes delivered to DEFS. Other operating revenues also include other operating revenues on TE Products and processing and other revenues on the Jonah gas gathering system. Amounts related to the Pioneer plant are classified as discontinued operations in the consolidated statements of income.

(13) Includes operating costs and expenses related to DEFS managing and operating the Jonah and Val Verde systems and the Chaparral NGL pipeline on our behalf under a contractual agreement established at the time of acquisition of each asset. In connection with the change in ownership of our General Partner, we have assumed these activities.

(14) Effective with the purchase of the fractionation facilities on March 31, 1998, TEPPCO Colorado and DEFS entered into an Operation and Maintenance Agreement, whereby DEFS operates and maintains the fractionation facilities for TEPPCO Colorado. For these services, TEPPCO Colorado pays DEFS a set volumetric rate for all fractionated volumes delivered to DEFS.

(15) Includes TCO purchases of condensate.

(16) Includes Jonah purchases of natural gas in connection with Jonah's Pioneer processing plant operations.

At December 31, 2005, we had a receivable from EPCO and affiliates of $4.3 million related to sales and transportation services provided to EPCO and affiliates. At December 31, 2005, we had a payable to EPCO and affiliates of $9.8 million related to direct payroll, payroll related costs and other operational related charges.

At December 31, 2004, we had a receivable from DEFS and affiliates of $10.5 million related to sales and transportation services provided to DEFS and affiliates. Included in this receivable balance from DEFS and affiliates at December 31, 2004, is a gas imbalance receivable of $0.9 million. At December 31, 2004, we had a payable to DEFS and affiliates of $22.4 million related to direct payroll, payroll related costs, management fees, and other operational related charges, including those for Jonah, Chaparral and Val Verde as described above. Included in this payable balance at December 31, 2004, is a gas imbalance payable to DEFS and affiliates of $3.2 million.

From February 24, 2005 through December 31, 2005, the majority of our insurance coverage, including property, liability, business interruption, auto and directors and officers' liability insurance, was obtained through EPCO. From February 24, 2005 through December 31, 2005, we incurred insurance expense related to premiums charged by EPCO of $9.8 million. At December 31, 2005, we had insurance reimbursement receivables due from EPCO of $1.3 million.

Through February 23, 2005, we contracted with Bison Insurance Company Limited ("Bison"), a wholly owned subsidiary of Duke Energy, for a majority of our insurance coverage, including property, liability, auto and directors and officers' liability insurance. Through February 23, 2005 and for the years ended December 31, 2004 and 2003, we incurred insurance expense related to premiums paid to Bison of $1.2 million, $6.5 million and $5.9 million, respectively. At December 31, 2004, we had insurance reimbursement receivables due from Bison of $5.2 million.

On April 2, 2003, we sold in an underwritten public offering 3.9 million Units at $30.35 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $114.5 million, of which approximately $113.8 million was used to repurchase and retire all of the 3.9 million previously outstanding Class B Units held by DETTCO.

Interest of the General Partner in the Partnership

We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. According to the Partnership Agreement, the Company receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds as follows:

	Unitholders	General Partner
Quarterly Cash Distribution per Unit:		
Up to Minimum Quarterly Distribution ($0.275 per Unit)	98%	2%
First Target - $0.276 per Unit up to $0.325 per Unit	85%	15%
Second Target - $0.326 per Unit up to $0.45 per Unit	75%	25%
Over Second Target - Cash distributions greater than $0.45 per Unit	50%	50%

During the year ended December 31, 2005, distributions paid to the General Partner totaled $73.2 million, including incentive distributions of $69.5 million.

Interests of DFI in the Partnership

At formation in 1990, we completed an initial public offering of 26,500,000 Units representing Limited Partner Interests. In connection with our formation, the Company received 2,500,000 DPIs. Effective April 1, 1994, the DPIs were converted to Units, but they have not been listed for trading on the New York Stock Exchange. These Units were assigned to Duke Energy when ownership of the Company was transferred from Duke Energy to DEFS in 2000. On February 24, 2005, DFI entered into an LP Unit Purchase and Sale Agreement with Duke Energy and purchased these 2,500,000 Units for $104.0 million. At December 31, 2005, we had outstanding 69,963,554 Units, including 2,500,000 Units held by DFI.

CONSOLIDATED FINANCIAL STATEMENTS
OF TEPPCO PARTNERS, L.P.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of
TEPPCO Partners, L.P.:

We have audited the accompanying consolidated balance sheets of TEPPCO Partners, L.P. as of December 31, 2005 and 2004, and the related consolidated statements of income, partners' capital and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of TEPPCO Partners, L.P. as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 20 to the consolidated financial statements, the Partnership has restated its consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, partners' capital and comprehensive income and cash flows for the years ended December 31, 2004 and 2003.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of TEPPCO Partners, L.P.'s internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2006, expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Houston, Texas
February 28, 2006, except for the effects of discontinued operations,
as discussed in Note 5, which is as of June 1, 2006

TEPPCO PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2005	December 31, 2004 (as restated)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 119	$ 16,422
Accounts receivable, trade (net of allowance for doubtful accounts of $250 and $112)	803,373	553,628
Accounts receivable, related parties	5,207	11,845
Inventories	29,069	19,521
Other	61,361	42,138
Total current assets	899,129	643,554
Property, plant and equipment, at cost (net of accumulated depreciation and amortization of $474,332 and $407,670)	1,960,068	1,703,702
Equity investments	359,656	363,307
Intangible assets	376,908	407,358
Goodwill	16,944	16,944
Other assets	67,833	51,419
Total assets	$ 3,680,538	$ 3,186,284
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 800,033	$ 564,464
Accounts payable, related parties	11,836	24,654
Accrued interest	32,840	32,292
Other accrued taxes	16,532	13,309
Other	75,970	46,593
Total current liabilities	937,211	681,312
Senior Notes	1,119,121	1,127,226
Other long-term debt	405,900	353,000
Other liabilities and deferred credits	16,936	13,643

Commitments and contingencies		
Partners' capital:		
Accumulated other comprehensive income	11	—
General partner's interest	(61,487)	(35,881)
Limited partners' interests	1,262,846	1,046,984
Total partners' capital	1,201,370	1,011,103
Total liabilities and partners' capital	$ 3,680,538	$ 3,186,284

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per Unit amounts)

	Years Ended December 31, 2005	2004 (as restated)	2003 (as restated)
Operating revenues:			
Sales of petroleum products	$ 8,061,808	$ 5,426,832	$ 3,766,651
Transportation — Refined products	144,552	148,166	138,926
Transportation — LPGs	96,297	87,050	91,787
Transportation — Crude oil	37,614	37,177	29,057
Transportation — NGLs	43,915	41,204	39,837
Gathering — Natural gas	152,797	140,122	135,144
Other	68,051	67,539	54,430
Total operating revenues	8,605,034	5,948,090	4,255,832
Costs and expenses:			
Purchases of petroleum products	7,986,438	5,367,027	3,711,207
Operating, general and administrative	218,920	219,909	198,478
Operating fuel and power	48,972	48,139	41,362
Depreciation and amortization	110,729	112,284	100,728
Taxes — other than income taxes	20,610	17,340	15,597
Gains on sales of assets	(668)	(1,053)	(3,948)
Total costs and expenses	8,385,001	5,763,646	4,063,424
Operating income	220,033	184,444	192,408
Interest expense — net	(81,861)	(72,053)	(84,250)
Equity earnings	20,094	22,148	12,874
Other income — net	1,135	1,320	748
Income from continuing operations	159,401	135,859	121,780
Discontinued operations	3,150	2,689	—
Net income	$ 162,551	$ 138,548	$ 121,780
Net Income Allocation:			
Limited Partner Unitholders income from continuing operations	$ 112,744	$ 96,667	$ 86,357
Limited Partner Unitholders income from discontinued operations	2,228	1,913	—
Total Limited Partner Unitholders net income allocation	114,972	98,580	86,357
Class B Unitholder net income allocation	—	—	1,754
General Partner income from continuing operations	46,657	39,192	33,669
General Partner income from discontinued operations	922	776	—
Total General Partner net income allocation	47,579	39,968	33,669
Total net income allocated	$ 162,551	$ 138,548	$ 121,780
Basic and diluted net income per Limited Partner and Class B Unit:			
Continuing operations	$ 1.67	$ 1.53	$ 1.47
Discontinued operations	0.04	0.03	—
Basic and diluted net income per Limited Partner and Class B Unit	$ 1.71	$ 1.56	$ 1.47
Weighted average Limited Partner and Class B Units outstanding	67,397	62,999	59,765

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Years Ended December 31, 2005	2004 (as restated)	2003 (as restated)
Cash flows from operating activities:			
Net income	$ 162,551	$ 138,548	$ 121,780
Adjustments to reconcile net income to cash provided by continuing operating activities:			
Income from discontinued operations	(3,150)	(2,689)	—
Depreciation and amortization	110,729	112,284	100,728
Earnings in equity investments, net of distributions	16,991	25,065	15,129
Gains on sales of assets	(668)	(1,053)	(3,948)
Non-cash portion of interest expense	1,624	(391)	4,793
Increase in accounts receivable	(249,745)	(181,690)	(100,085)
Decrease (increase) in accounts receivable, related parties	6,638	(14,693)	8,788
Increase in inventories	(970)	(3,433)	(956)
Increase in other current assets	(19,088)	(9,926)	(953)
Increase in accounts payable and accrued expenses	254,251	186,942	95,540
Increase (decrease) in accounts payable, related parties	(12,817)	4,360	7,381
Other	(15,623)	10,572	(5,773)
Net cash provided by continuing operating activities	250,723	263,896	242,424
Net cash provided by discontinued operations	3,782	3,271	—
Net cash provided by operating activities	254,505	267,167	242,424
Cash flows from continuing investing activities:			
Proceeds from sales of assets	510	1,226	8,531
Proceeds from cash investments	—	—	750
Purchase of assets	(112,231)	(3,421)	(27,469)
Investment in Mont Belvieu Storage Partners, L.P.	(4,233)	(21,358)	(2,533)
Investment in Centennial Pipeline LLC	—	(1,500)	(4,000)
Purchase of additional interest in Centennial Pipeline LLC	—	—	(20,000)
Cash paid for linefill on assets owned	(14,408)	(957)	(3,070)
Capital expenditures	(220,553)	(156,749)	(126,707)
Net cash used in continuing investing activities	(350,915)	(182,759)	(174,498)
Net cash used in discontinued investing activities	—	(7,398)	(13,810)
Net cash used in investing activities	(350,915)	(190,157)	(188,308)
Cash flows from financing activities:			
Proceeds from revolving credit facility	657,757	324,200	382,000
Issuance of Limited Partner Units, net	278,806	—	287,506
Issuance of Senior Notes	—	—	198,570
Repayments on revolving credit facility	(604,857)	(181,200)	(604,000)
Repurchase and retirement of Class B Units	—	—	(113,814)
Debt issuance costs	(498)	—	(3,381)
General Partner’s contributions	—	—	2
Distributions paid	(251,101)	(233,057)	(202,498)
Net cash provided by (used in) financing activities	80,107	(90,057)	(55,615)
Net decrease in cash and cash equivalents	(16,303)	(13,047)	(1,499)
Cash and cash equivalents at beginning of period	16,422	29,469	30,968
Cash and cash equivalents at end of period	$ 119	$ 16,422	$ 29,469
Non-cash investing activities:			
Net assets transferred to Mont Belvieu Storage Partners, L.P.	$ 1,429	$ —	$ 61,042
Supplemental disclosure of cash flows:			
Cash paid for interest (net of amounts capitalized)	$ 82,315	$ 77,510	$ 79,930

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS’ CAPITAL
(in thousands, except Unit amounts)

	Outstanding Limited Partner Units	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive (Loss) Income	Total
Partners' capital at December 31, 2002 (as restated)	53,809,597	$ 12,104	$ 897,400	$ (20,055)	$ 889,449
Issuance of Limited Partner Units, net	9,101,650	—	285,461	—	285,461
Retirement of Class B units	—	—	(11,175)	—	(11,175)
Net income on cash flow hedge	—	—	—	16,164	16,164
Reclassification due to discontinued portion of cash flow hedge	—	—	—	989	989
2003 net income allocation	—	33,669	86,357	—	120,026
2003 cash distributions	—	(54,725)	(145,427)	—	(200,152)
Issuance of Limited Partner Units upon exercise of options	87,307	2	2,045	—	2,047
Partners' capital at December 31, 2003 (as restated)	62,998,554	(8,950)	1,114,661	(2,902)	1,102,809
Adjustments to issuance of Limited Partner Units, net	—	—	(99)	—	(99)
Net income on cash flow hedge	—	—	—	2,902	2,902
2004 net income allocation	—	39,968	98,580	—	138,548
2004 cash distributions	—	(66,899)	(166,158)	—	(233,057)
Partners' capital at December 31, 2004 (as restated)	62,998,554	(35,881)	1,046,984	—	1,011,103
Issuance of Limited Partner Units, net	6,965,000	—	278,806	—	278,806
Changes in fair values of crude oil hedges	—	—	—	11	11
2005 net income allocation	—	47,579	114,972	—	162,551
2005 cash distributions	—	(73,185)	(177,916)	—	(251,101)
Partners' capital at December 31, 2005	69,963,554	$ (61,487)	$ 1,262,846	$ 11	$ 1,201,370

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Years Ended December 31, 2005	2004 (as restated)	2003 (as restated)
Net income	$ 162,551	$ 138,548	$ 121,780
Net income on cash flow hedges	11	—	16,164
Comprehensive income	$ 162,562	$ 138,548	$ 137,944

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. PARTNERSHIP ORGANIZATION

TEPPCO Partners, L.P. (the "Partnership"), a Delaware limited partnership, is a master limited partnership formed in March 1990. We operate through TE Products Pipeline Company, Limited Partnership ("TE Products"), TCTM, L.P. ("TCTM") and TEPPCO Midstream Companies, L.P. ("TEPPCO Midstream"). Collectively, TE Products, TCTM and TEPPCO Midstream are referred to as the "Operating Partnerships." Texas Eastern Products Pipeline Company, LLC (the "Company" or "General Partner"), a Delaware limited liability company, serves as our general partner and owns a 2% general partner interest in us.

On July 26, 2001, the Company restructured its general partner ownership of the Operating Partnerships to cause them to be indirectly wholly owned by us. TEPPCO GP, Inc. ("TEPPCO GP"), our subsidiary, succeeded the Company as general partner of the Operating Partnerships. All remaining partner interests in the Operating Partnerships not already owned by us were transferred to us. In exchange for this contribution, the Company's interest as our general partner was increased to 2%. The increased percentage is the economic equivalent of the aggregate interest that the Company had prior to the restructuring through its combined interests in us and the Operating Partnerships. As a result, we hold a 99.999% limited partner interest in the Operating Partnerships and TEPPCO GP holds a 0.001% general partner interest. This reorganization was undertaken to simplify required financial reporting by the Operating Partnerships when the Operating Partnerships issue guarantees of our debt.

Through February 23, 2005, the General Partner was an indirect wholly owned subsidiary of Duke Energy Field Services, LLC ("DEFS"), a joint venture between Duke Energy Corporation ("Duke Energy") and ConocoPhillips. Duke Energy held an interest of approximately 70% in DEFS, and ConocoPhillips held the remaining interest of approximately 30%. On February 24, 2005, the General Partner was acquired by DFI GP Holdings L.P. (formerly Enterprise GP Holdings L.P.) ("DFI"), an affiliate of EPCO, Inc. ("EPCO"), a privately held company controlled by Dan L. Duncan, for approximately $1.1 billion. As a result of the transaction, DFI owns and controls the 2% general partner interest in us and has the right to receive the incentive distribution rights associated with the general partner interest. In conjunction with an amended and restated administrative services agreement, EPCO performs all management, administrative and operating functions required for us, and we reimburse EPCO for all direct and indirect expenses that have been incurred in managing us. As a result of the sale of our General Partner, DEFS and Duke Energy continued to provide some administrative services for us for a period of up to one year after the sale, at which time, we assumed these services. In connection with us assuming the operations of certain of the TEPPCO Midstream assets from DEFS, certain DEFS employees became employees of EPCO effective June 1, 2005.

At formation in 1990, we completed an initial public offering of 26,500,000 units representing Limited Partner Interests ("Limited Partner Units") at $10.00 per Limited Partner Unit. In connection with our formation, the Company received 2,500,000 Deferred Participation Interests ("DPIs"). Effective April 1, 1994, the DPIs were converted to Limited Partner Units, but they have not been listed for trading on the New York Stock Exchange. These Limited Partner Units were assigned to Duke Energy when ownership of the Company was transferred from Duke Energy to DEFS in 2000. On February 24, 2005, DFI entered into an LP Unit Purchase and Sale Agreement with Duke Energy and purchased these 2,500,000 Limited Partner Units for $104.0 million. As of December 31, 2005, none of these Limited Partner Units had been sold by DFI.

At December 31, 2005, 2004 and 2003, we had outstanding 69,963,554, 62,998,554 and 62,998,554 Limited Partner Units, respectively. At December 31, 2002, we had outstanding 3,916,547 Class B Limited Partner Units ("Class B Units"), which were issued to Duke Energy Transport and Trading Company, LLC ("DETTCO") in connection with an acquisition of assets initially acquired in 1998. On April 2, 2003, we repurchased and retired all of the 3,916,547 previously outstanding Class B Units with proceeds from the issuance of additional Limited Partner Units (see Note 11). Collectively, the Limited Partner Units and Class B Units are referred to as "Units".

As used in this Report, "we," "us," "our," the "Partnership" and "TEPPCO" mean TEPPCO Partners, L.P. and, where the context requires, include our subsidiaries.

We restated our consolidated financial statements and related financial information for the years ended December 31, 2004 and 2003, for an accounting correction. In addition, the restatement adjustment impacted quarterly periods with the fiscal years ended December 31, 2005, 2004 and 2003. See Note 20 for a discussion of the restatement adjustment and the impact on previously issued financial statements.

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

We adhere to the following significant accounting policies in the preparation of our consolidated financial statements.

Basis of Presentation and Principles of Consolidation

Throughout the consolidated financial statements and accompanying notes, all referenced amounts related to prior periods reflect the balances and amounts on a restated basis. The financial statements include our accounts on a consolidated basis. We have eliminated all significant intercompany items in consolidation. We have reclassified certain amounts from prior periods to conform to the current presentation. Our results for the years ended December 31, 2005 and 2004 reflect the operations and activities of Jonah Gas Gathering Company's Pioneer plant as discontinued operations.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Although we believe these estimates are reasonable, actual results could differ from those estimates.

Business Segments

We operate and report in three business segments: transportation and storage of refined products, liquefied petroleum gases ("LPGs") and petrochemicals ("Downstream Segment"); gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals ("Upstream Segment"); and gathering of natural gas, fractionation of natural gas liquids ("NGLs") and transportation of NGLs ("Midstream Segment"). Our reportable segments offer different products and services and are managed separately because each requires different business strategies.

Our interstate transportation operations, including rates charged to customers, are subject to regulations prescribed by the Federal Energy Regulatory Commission ("FERC"). We refer to refined products, LPGs, petrochemicals, crude oil, NGLs and natural gas in this Report, collectively, as "petroleum products" or "products."

Revenue Recognition

Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. Transportation revenues are recognized as products are delivered to customers. Storage revenues are recognized upon receipt of products into storage and upon performance of storage services. Terminaling revenues are recognized as products are out-loaded. Revenues from the sale of product inventory are recognized when the products are sold.

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil, and distribution of lubrication oils and specialty chemicals principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Revenues are also generated from trade documentation and pumpover services, primarily at Cushing, Oklahoma, and Midland, Texas. Revenues are accrued at the time title to the product sold transfers to the purchaser, which typically occurs upon receipt of the product by the purchaser, and purchases are accrued at the time title to the product purchased transfers to our crude oil marketing company, TEPPCO Crude Oil, L.P. ("TCO"), which typically occurs upon our receipt of the product. Revenues related to trade documentation and pumpover fees are recognized as services are completed.

Except for crude oil purchased from time to time as inventory, our policy is to purchase only crude oil for which we have a market to sell and to structure sales contracts so that crude oil price fluctuations do not materially affect the margin received. As we purchase crude oil, we establish a margin by selling crude oil for physical delivery to third party users or by entering into a future delivery obligation. Through these transactions, we seek to maintain a position that is balanced between crude oil purchases and sales and future delivery obligations. However, certain basis risks (the risk that price relationships between delivery points, classes of products or delivery periods will change) cannot be completely hedged.

Our Midstream Segment revenues are earned from the gathering of natural gas, transportation of NGLs and fractionation of NGLs. Gathering revenues are recognized as natural gas is received from the customer. Transportation revenues are recognized as NGLs are delivered to customers. Revenues are also earned from the sale of condensate liquid extracted from the natural gas stream to an Upstream Segment marketing affiliate. Fractionation revenues are recognized ratably over the contract year as products are delivered. We generally do not take title to the natural gas gathered, NGLs transported or NGLs fractionated, with the exception of inventory imbalances discussed in "Natural Gas Imbalances." Therefore, the results of our Midstream Segment are not directly affected by changes in the prices of natural gas or NGLs.

Cash and Cash Equivalents

Cash equivalents are defined as all highly marketable securities with maturities of three months or less when purchased. The carrying value of cash and cash equivalents approximate fair value because of the short term nature of these investments.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of the outstanding balance. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. The following table presents the activity of our allowance for doubtful accounts for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,		
	2005	2004	2003
Balance at beginning of period	$ 112	$ 4,700	$ 4,608
Charges to expense	829	536	793
Deductions and other	(691)	(5,124)	(701)
Balance at end of period	$ 250	$ 112	$ 4,700

Inventories

Inventories consist primarily of petroleum products and crude oil, which are valued at the lower of cost (weighted average cost method) or market. Our Downstream Segment acquires and disposes of various products under exchange agreements. Receivables and payables arising from these transactions are usually satisfied with

products rather than cash. The net balances of exchange receivables and payables are valued at weighted average cost and included in inventories. Inventories of materials and supplies, used for ongoing replacements and expansions, are carried at the lower of fair value or cost.

Property, Plant and Equipment

We record property, plant and equipment at its acquisition cost. Additions to property, plant and equipment, including major replacements or betterments, are recorded at cost. We charge replacements and renewals of minor items of property that do not materially increase values or extend useful lives to maintenance expense. Depreciation expense is computed on the straight-line method using rates based upon expected useful lives of various classes of assets (ranging from 2% to 20% per annum).

We evaluate impairment of long-lived assets in accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of the carrying amount of assets to be held and used is measured by a comparison of the carrying amount of the asset to estimated future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the estimated fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or estimated fair value less costs to sell.

Asset Retirement Obligations

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS 143 requires us to record the fair value of an asset retirement obligation as a liability in the period in which we incur a legal obligation for the retirement of tangible long-lived assets. A corresponding asset is also recorded and depreciated over the life of the asset. After the initial measurement of the asset retirement obligation, the liability will be adjusted at the end of each reporting period to reflect changes in the estimated future cash flows underlying the obligation. Determination of any amounts recognized upon adoption is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rates.

The Downstream Segment assets consist primarily of an interstate trunk pipeline system and a series of storage facilities that originate along the upper Texas Gulf Coast and extend through the Midwest and northeastern United States. We transport refined products, LPGs and petrochemicals through the pipeline system. These products are primarily received in the south end of the system and stored and/or transported to various points along the system per customer nominations. The Upstream Segment's operations include purchasing crude oil from producers at the wellhead and providing delivery, storage and other services to its customers. The properties in the Upstream Segment consist of interstate trunk pipelines, pump stations, trucking facilities, storage tanks and various gathering systems primarily in Texas and Oklahoma. The Midstream Segment gathers natural gas from wells owned by producers and delivers natural gas and NGLs on its pipeline systems, primarily in Texas, Wyoming, New Mexico and Colorado. The Midstream Segment also owns and operates two NGL fractionator facilities in Colorado.

We have completed our assessment of SFAS 143, and we have determined that we are obligated by contractual or regulatory requirements to remove certain facilities or perform other remediation upon retirement of our assets. However, we are not able to reasonably determine the fair value of the asset retirement obligations for our trunk, interstate and gathering pipelines and our surface facilities, since future dismantlement and removal dates are indeterminate.

In order to determine a removal date for our gathering lines and related surface assets, reserve information regarding the production life of the specific field is required. As a transporter and gatherer of crude oil and natural

gas, we are not a producer of the field reserves, and we therefore do not have access to adequate forecasts that predict the timing of expected production for existing reserves on those fields in which we gather crude oil and natural gas. In the absence of such information, we are not able to make a reasonable estimate of when future dismantlement and removal dates of our gathering assets will occur. With regard to our trunk and interstate pipelines and their related surface assets, it is impossible to predict when demand for transportation of the related products will cease. Our right-of-way agreements allow us to maintain the right-of-way rather than remove the pipe. In addition, we can evaluate our trunk pipelines for alternative uses, which can be and have been found.

We will record such asset retirement obligations in the period in which more information becomes available for us to reasonably estimate the settlement dates of the retirement obligations. The adoption of SFAS 143 did not have an effect on our financial position, results of operations or cash flows.

Capitalization of Interest

We capitalize interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average rate used to capitalize interest on borrowed funds was 5.73%, 5.74% and 6.50% for the years ended December 31, 2005, 2004 and 2003, respectively. During the years ended December 31, 2005, 2004 and 2003, the amount of interest capitalized was $6.8 million, $4.2 million and $5.3 million, respectively.

Intangible Assets

Intangible assets on the consolidated balance sheets consist primarily of gathering contracts assumed in the acquisition of Jonah Gas Gathering System ("Jonah") on September 30, 2001, and the acquisition of Val Verde Gathering System ("Val Verde") on June 30, 2002, a fractionation agreement and other intangible assets (see Note 3). Included in equity investments on the consolidated balance sheets are excess investments in Centennial Pipeline LLC ("Centennial") and Seaway Crude Pipeline Company ("Seaway").

In connection with the acquisitions of Jonah and Val Verde, we assumed contracts that dedicate future production from natural gas wells in the Green River Basin in Wyoming, and we assumed fixed-term contracts with customers that gather coal bed methane ("CBM") from the San Juan Basin in New Mexico and Colorado, respectively. The value assigned to these intangible assets relates to contracts with customers that are for either a fixed term or which dedicate total future lease production to the gathering system. These intangible assets are amortized on a unit-of-production basis, based upon the actual throughput of the system over the expected total throughput for the lives of the contracts. Revisions to the unit-of-production estimates may occur as additional production information is made available to us (see Note 3).

In connection with the purchase of the fractionation facilities in 1998, we entered into a fractionation agreement with DEFS. The fractionation agreement is being amortized on a straight-line basis over a period of 20 years, which is the term of the agreement with DEFS.

In connection with the acquisition of crude supply and transportation assets in November 2003, we acquired intangible customer contracts for $8.7 million, which are amortized on a unit-of-production basis (see Note 5).

In connection with the formation of Centennial, we recorded excess investment, the majority of which is amortized on a unit-of-production basis over a period of 10 years. In connection with the acquisition of our interest in Seaway, we recorded excess investment, which is amortized on a straight-line basis over a period of 39 years (see Note 3).

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired and is presented on the consolidated balance sheets net of accumulated amortization. We account for goodwill under SFAS No. 142, *Goodwill and Other Intangible Assets*, which was issued by the FASB in July 2001 (see Note 3). SFAS 142 prohibits amortization of goodwill and intangible assets with indefinite useful lives, but instead requires testing for impairment at least annually. SFAS 142 requires that intangible assets with definite useful lives be amortized over their respective estimated useful lives. Beginning January 1, 2002, effective with the adoption of SFAS 142, we no longer record amortization expense related to goodwill.

Environmental Expenditures

We accrue for environmental costs that relate to existing conditions caused by past operations. Environmental costs include initial site surveys and environmental studies of potentially contaminated sites, costs for remediation and restoration of sites determined to be contaminated and ongoing monitoring costs, as well as damages and other costs, when estimable. We monitor the balance of accrued undiscounted environmental liabilities on a regular basis. We record liabilities for environmental costs at a specific site when our liability for such costs is probable and a reasonable estimate of the associated costs can be made. Adjustments to initial estimates are recorded, from time to time, to reflect changing circumstances and estimates based upon additional information developed in subsequent periods. Estimates of our ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation alternatives available and the evolving nature of environmental laws and regulations.

The following table presents the activity of our environmental reserve for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,		
	2005	2004	2003
Balance at beginning of period	$5,037	$7,639	$7,693
Charges to expense	2,530	5,178	6,824
Deductions and other	(5,120)	(7,780)	(6,878)
Balance at end of period	$2,447	$5,037	$7,639

Natural Gas Imbalances

Gas imbalances occur when gas producers (customers) deliver more or less actual natural gas gathering volumes to our gathering systems than they originally nominated. Actual deliveries are different from nominated volumes due to fluctuations in gas production at the wellhead. If the customers supply more natural gas gathering volumes than they nominated, Val Verde and Jonah record a payable for the amount due to customers and also record a receivable for the same amount due from connecting pipeline transporters or shippers. To the extent that these amounts are not cashed out monthly on Val Verde, if the customers supply less natural gas gathering volumes than they nominated, Val Verde and Jonah record a receivable reflecting the amount due from customers and a payable for the same amount due to connecting pipeline transporters or shippers. We record natural gas imbalances using a mark-to-market approach.

Income Taxes

We are a limited partnership. As such, we are not a taxable entity for federal and state income tax purposes and do not directly pay federal and state income tax. Our taxable income or loss, which may vary substantially from

the net income or net loss we report in our consolidated statements of income, is includable in the federal and state income tax returns of each unitholder. Accordingly, no recognition has been given to federal and state income taxes for our operations. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each unitholders' tax attributes in the Partnership.

Use of Derivatives

We account for derivative financial instruments in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* and SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133.* These statements establish accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet at fair value as either assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative.

Our derivative instruments consist primarily of interest rate swaps and contracts for the purchase and sale of petroleum products in connection with our crude oil marketing activities. Substantially all derivative instruments related to our crude oil marketing activities meet the normal purchases and sales criteria of SFAS 133, as amended, and as such, changes in the fair value of petroleum product purchase and sales agreements are reported on the accrual basis of accounting. SFAS 133 describes normal purchases and sales as contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold by the reporting entity over a reasonable period in the normal course of business.

For all hedging relationships, we formally document at inception the hedging relationship and its risk-management objective and strategy for undertaking the hedge, the hedging instrument, the item, the nature of the risk being hedged, how the hedging instrument's effectiveness in offsetting the hedged risk will be assessed and a description of the method of measuring ineffectiveness. This process includes linking all derivatives that are designated as fair value or cash flow to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. We also formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. If it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively.

For derivative instruments designated as fair value hedges, gains and losses on the derivative instrument are offset against related results on the hedged item in the statement of income. Changes in the fair value of a derivative that is highly effective and that is designated and qualifies as a fair value hedge, along with the loss or gain on the hedged asset or liability or unrecognized firm commitment of the hedged item that is attributable to the hedged risk, are recorded in earnings. Changes in the fair value of a derivative that is highly effective and that is designated and qualifies as a cash flow hedge are recorded in other comprehensive income to the extent that the derivative is effective as a hedge, until earnings are affected by the variability in cash flows of the designated hedged item. Hedge effectiveness is measured at least quarterly based on the relative cumulative changes in fair value between the derivative contract and the hedged item over time. The ineffective portion of the change in fair value of a derivative instrument that qualifies as either a fair value hedge or a cash flow hedge is reported immediately in earnings.

According to SFAS 133, as amended, we are required to discontinue hedge accounting prospectively when it is determined that the derivative is no longer effective in offsetting changes in the fair value or cash flows of the hedged item, the derivative expires or is sold, terminated, or exercised, the derivative is de-designated as a hedging instrument, because it is unlikely that a forecasted transaction will occur, a hedged firm commitment no longer

meets the definition of a firm commitment, or management determines that designation of the derivative as a hedging instrument is no longer appropriate.

When hedge accounting is discontinued because it is determined that the derivative no longer qualifies as an effective fair value hedge, we continue to carry the derivative on the balance sheet at its fair value and no longer adjust the hedged asset or liability for changes in fair value. The adjustment of the carrying amount of the hedged asset or liability is accounted for in the same manner as other components of the carrying amount of that asset or liability. When hedge accounting is discontinued because the hedged item no longer meets the definition of a firm commitment, we continue to carry the derivative on the balance sheet at its fair value, remove any asset or liability that was recorded pursuant to recognition of the firm commitment from the balance sheet, and recognize any gain or loss in earnings. When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, we continue to carry the derivative on the balance sheet at its fair value with subsequent changes in fair value included in earnings, and gains and losses that were accumulated in other comprehensive income are recognized immediately in earnings. In all other situations in which hedge accounting is discontinued, we continue to carry the derivative at its fair value on the balance sheet and recognize any subsequent changes in its fair value in earnings.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, accounts receivable, inventories, other current assets, accounts payable and accrued liabilities, other current liabilities and derivatives approximates their fair value due to their short-term nature. The fair values of these financial instruments are represented in our consolidated balance sheets.

Net Income Per Unit

Basic net income per Unit is computed by dividing net income, after deduction of the General Partner's interest, by the weighted average number of Units outstanding (a total of 67.4 million Units, 63.0 million Units and 59.8 million Units for the years ended December 31, 2005, 2004 and 2003, respectively). The General Partner's percentage interest in our net income is based on its percentage of cash distributions from Available Cash for each year (see Note 11). The General Partner was allocated $47.6 million (representing 29.27%) of net income for the year ended December 31, 2005, $40.0 million (representing 28.85%) of net income for the year ended December 31, 2004, and $33.7 million (representing 27.65%) of net income for the year ended December 31, 2003. The General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase, in accordance with our limited partnership agreement.

Diluted net income per Unit is similar to the computation of basic net income per Unit discussed above, except that the denominator is increased to include the dilutive effect of outstanding Unit options by application of the treasury stock method. For the year ended December 31, 2003, the denominator was increased by 11,878 Units. For the years ended December 31, 2005 and 2004, diluted net income per Unit equaled basic net income per Unit as all remaining outstanding Unit options were exercised during the third quarter of 2003 (see Note 13).

Unit Option Plan

We have not granted options for any periods presented. For options outstanding under the 1994 Long Term Incentive Plan (see Note 13), we followed the intrinsic value method of accounting for recognizing stock-based compensation expense. Under this method, we record no compensation expense for Unit options granted when the exercise price of the options granted is equal to, or greater than, the market price of our Units on the date of the grant. During the year ended December 31, 2003, all remaining outstanding Unit options were exercised.

In December 2002, SFAS No. 148, *Accounting for Stock-Based Compensation — Transition and Disclosure* was issued. SFAS 148 amends SFAS No. 123, *Accounting for Stock-Based Compensation*, and provides alternative

methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS 148 amends the disclosure requirements of SFAS 123 to require prominent disclosure in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002, and are included in Note 13.

Assuming we had used the fair value method of accounting for our Unit option plan, pro forma net income would equal reported net income for the years ended December 31, 2005, 2004 and 2003. Pro forma net income per Unit would equal reported net income per Unit for the periods presented. The adoption of SFAS 148 did not have an effect on our financial position, results of operations or cash flows.

New Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123(R), *Share-Based Payment*. SFAS 123(R) requires compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, the amount of the compensation cost is to be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards are to be re-measured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. SFAS 123(R) is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*, as amended by SFAS No. 148, *Accounting for Stock-Based Compensation — Transition and Disclosure* and supersedes Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees*. SFAS 123(R) is effective for public companies as of the first interim or annual reporting period of the first fiscal year beginning after June 15, 2005. The Securities and Exchange Commission amended the implementation date of SFAS 123(R) to begin with the first interim or annual reporting period of the company's first fiscal year beginning on or after June 15, 1005. As such, we will adopt SFAS 123(R) in the first quarter of 2006. Companies are permitted to adopt SFAS 123(R) prior to the extended date. All public companies that adopted the fair-value-based method of accounting must use the modified prospective transition method and may elect to use the modified retrospective transition method. We do not believe that the adoption of SFAS 123(R) will have a material effect on our financial position, results of operations or cash flows.

In November 2004, the Emerging Issues Task Force ("EITF") reached consensus in EITF 03-13, *Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations*, to clarify whether a component of an enterprise that is either disposed of or classified as held for sale qualifies for income statement presentation as discontinued operations. The FASB ratified the consensus on November 30, 2004. The consensus is to be applied prospectively with regard to a component of an enterprise that is either disposed of or classified as held for sale in reporting periods beginning after December 15, 2004. The consensus may be applied retrospectively for previously reported operating results related to disposal transactions initiated within an enterprise's reporting period that included the date that this consensus was ratified. The adoption of EITF 03-13 did not have an effect on our financial position, results of operations or cash flows.

In March 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* ("FIN 47"). FIN 47 clarifies that the term, conditional asset retirement obligation as used in SFAS No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional upon a future event that may or may not be within the control of the entity. Even though uncertainty about the timing and/or method of settlement exists and may be conditional upon a future event, the obligation to perform the asset retirement activity is unconditional. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset

retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing and/or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred generally upon acquisition, construction, or development or through the normal operation of the asset. SFAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective no later than the end of reporting periods ending after December 15, 2005, and early adoption of FIN 47 is encouraged. We adopted FIN 47 in the fourth quarter of 2005. The adoption of FIN 47 did not have a material effect on our financial position, results of operations or cash flows.

In June 2005, the EITF reached consensus in EITF 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights*, to provide guidance on how general partners in a limited partnership should determine whether they control a limited partnership and therefore should consolidate it. The EITF agreed that the presumption of general partner control would be overcome only when the limited partners have either of two types of rights. The first type, referred to as kick-out rights, is the right to dissolve or liquidate the partnership or otherwise remove the general partner without cause. The second type, referred to as participating rights, is the right to effectively participate in significant decisions made in the ordinary course of the partnership's business. The kick-out rights and the participating rights must be substantive in order to overcome the presumption of general partner control. The consensus is effective for general partners of all new limited partnerships formed and for existing limited partnerships for which the partnership agreements are modified subsequent to the date of FASB ratification (June 29, 2005). For existing limited partnerships that have not been modified, the guidance in EITF 04-5 is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005. We do not believe that the adoption of EITF 04-5 will have a material effect on our financial position, results of operations or cash flows.

In December 2004, the FASB issued SFAS No. 153, *Exchanges of Nonmonetary Assets, an amendment of APB Opinion 29*. SFAS 153 amends APB Opinion No. 29, *Accounting for Nonmonetary Exchanges,* to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. We adopted SFAS 153 during the second quarter of 2005. The adoption of SFAS 153 did not have a material effect on our financial position, results of operations or cash flows.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections*. SFAS 154 establishes new standards on accounting for changes in accounting principles. All such changes must be accounted for by retrospective application to the financial statements of prior periods unless it is impracticable to do so. SFAS 154 completely replaces APB Opinion No. 20, *Accounting Changes,* and SFAS No. 3, *Reporting Accounting Changes in Interim Periods*. However, it carries forward the guidance in those pronouncements with respect to accounting for changes in estimates, changes in the reporting entity, and the correction of errors. SFAS 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005, with early adoption permitted for changes and corrections made in years beginning after June 1, 2005. The application of SFAS 154 does not affect the transition provisions of any existing pronouncements, including those that are in the transition phase as of the effective date of SFAS 154. We do not believe that the adoption of SFAS 154 will have a material effect on our financial position, results of operations or cash flows.

In September 2005, the EITF reached consensus in EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, to define when a purchase and a sale of inventory with the same party that operates in the same line of business should be considered a single nonmonetary transaction subject to APB Opinion No. 29, *Accounting for Nonmonetary Transactions*. Two or more inventory transactions with the same party should be combined if they are entered into in contemplation of one another. The EITF also requires entities to account for

exchanges of inventory in the same line of business at fair value or recorded amounts based on inventory classification. The guidance in EITF 04-13 is effective for new inventory arrangements entered into in reporting periods beginning after March 15, 2006. We are currently evaluating what impact EITF 04-

13 will have on our financial statements, but at this time we do not believe that the adoption of EITF 04-13 will have a material effect on our financial position, results of operations or cash flows.

NOTE 3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired and is presented on the consolidated balance sheets net of accumulated amortization. We account for goodwill under SFAS No. 142, *Goodwill and Other Intangible Assets*, which was issued by the FASB in July 2001. SFAS 142 prohibits amortization of goodwill and intangible assets with indefinite useful lives, but instead requires testing for impairment at least annually. We test goodwill and intangible assets for impairment annually at December 31.

To perform an impairment test of goodwill, we have identified our reporting units and have determined the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill and intangible assets, to those reporting units. We then determine the fair value of each reporting unit and compare it to the carrying value of the reporting unit. We will continue to compare the fair value of each reporting unit to its carrying value on an annual basis to determine if an impairment loss has occurred. There have been no goodwill impairment losses recorded since the adoption of SFAS 142.

The following table presents the carrying amount of goodwill at December 31, 2005 and 2004, by business segment (in thousands):

	Downstream Segment	Midstream Segment	Upstream Segment	Segments Total
Goodwill	$ —	$ 2,777	$ 14,167	$ 16,944

Other Intangible Assets

The following table reflects the components of intangible assets, including excess investments, being amortized at December 31, 2005 and 2004 (in thousands):

	December 31, 2005		December 31, 2004	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible assets:				
Gathering and transportation agreements	$ 464,337	$ (118,921)	$ 464,337	$ (91,262)
Fractionation agreement	38,000	(14,725)	38,000	(12,825)
Other	10,226	(2,009)	12,262	(3,154)
Subtotal	$ 512,563	$ (135,655)	$ 514,599	$ (107,241)
Excess investments:				
Centennial Pipeline LLC	$ 33,400	$ (12,947)	$ 33,400	$ (8,875)
Seaway Crude Pipeline Company	27,100	(3,764)	27,100	(3,072)
Subtotal	$ 60,500	$ (16,711)	$ 60,500	$ (11,947)
Total intangible assets	$ 573,063	$ (152,366)	$ 575,099	$ (119,188)

SFAS 142 requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. Amortization expense on intangible assets was $30.5 million, $32.2 million and $36.2 million for the years ended December 31, 2005, 2004 and 2003, respectively. Amortization expense on excess investments included in equity earnings was $4.8 million, $3.8 million and $4.0 million for the years ended December 31, 2005, 2004 and 2003, respectively.

The values assigned to our intangible assets for natural gas gathering contracts on the Jonah and the Val Verde systems are amortized on a unit-of-production basis, based upon the actual throughput of the systems compared to the expected total throughput for the lives of the contracts. On a quarterly basis, we may obtain limited production forecasts and updated throughput estimates from some of the producers on the systems, and as a result, we evaluate the remaining expected useful lives of the contract assets based on the best available information. During the fourth quarter of 2004 and the first and second quarters of 2005, certain limited production forecasts were obtained from some of the producers on the Jonah system related to future expansions of the system, and as a result, we increased our best estimate of future throughput on the system, which resulted in extensions in the remaining lives of the intangible assets. During the fourth quarter of 2004 and the third quarter of 2005, certain limited coal bed methane production forecasts were obtained from some of the producers on the Val Verde system whose contracts are included in the intangible assets. These forecasts indicated lower coal bed methane production estimates over the contract periods, and as a result, we decreased our best estimate of future throughput on the Val Verde system, which resulted in increases to amortization expense on the intangible assets. Further revisions to these estimates may occur as additional production information is made available to us.

The values assigned to our fractionation agreement and other intangible assets are generally amortized on a straight-line basis. Our fractionation agreement is being amortized over its contract period of 20 years. The amortization periods for our other intangible assets, which include non-compete and other agreements, range from 3 years to 15 years. The value of $8.7 million assigned to our crude supply and transportation intangible customer contracts is being amortized on a unit-of-production basis (see Note 5).

The value assigned to our excess investment in Centennial was created upon its formation. Approximately $30.0 million is related to a contract and is being amortized on a unit-of-production basis based upon the volumes transported under the contract compared to the guaranteed total throughput of the contract over a 10-year life. The remaining $3.4 million is related to a pipeline and is being amortized on a straight-line basis over the life of the pipeline, which is 35 years. The value assigned to our excess investment in Seaway was created upon acquisition of our 50% ownership interest in 2000. We are amortizing the $27.1 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to the life of the pipeline.

The following table sets forth the estimated amortization expense of intangible assets and the estimated amortization expense allocated to equity earnings for the years ending December 31 (in thousands):

	Intangible Assets	Excess Investments
2006	$ 32,561	$ 4,691
2007	33,395	5,113
2008	32,967	5,438
2009	30,719	6,878
2010	27,338	7,042

NOTE 4. INTEREST RATE SWAPS

In July 2000, we entered into an interest rate swap agreement to hedge our exposure to increases in the benchmark interest rate underlying our variable rate revolving credit facility. This interest rate swap matured in April 2004. We designated this swap agreement, which hedged exposure to variability in expected future cash flows attributed to changes in interest rates, as a cash flow hedge. The swap agreement was based on a notional amount of $250.0 million. Under the swap agreement, we paid a fixed rate of interest of 6.955% and received a floating rate based on a three-month U.S. Dollar LIBOR rate. Because this swap was designated as a cash flow hedge, the changes in fair value, to the extent the swap was effective, were recognized in other comprehensive income until the hedged interest costs were recognized in earnings. During the years ended December 31, 2004 and 2003, we recognized an increase in interest expense of $2.9 million and $14.4 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap.

In October 2001, TE Products entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its fixed rate 7.51% Senior Notes due 2028. We designated this swap agreement as a fair value hedge. The swap agreement has a notional amount of $210.0 million and matures in January 2028 to match the principal and maturity of the TE Products Senior Notes. Under the swap agreement, TE Products pays a floating rate of interest based on a three-month U.S. Dollar LIBOR rate, plus a spread, and receives a fixed rate of interest of 7.51%. During the years ended December 31, 2005, 2004 and 2003, we recognized reductions in interest expense of $5.6 million, $9.6 million and $10.0 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. During the years ended December 31, 2005, 2004 and 2003, we measured the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized. The fair value of this interest rate swap was a loss of approximately $0.9 million at December 31, 2005, and a gain of approximately $3.4 million at December 31, 2004.

During 2002, we entered into interest rate swap agreements, designated as fair value hedges, to hedge our exposure to changes in the fair value of our fixed rate 7.625% Senior Notes due 2012. The swap agreements had a combined notional amount of $500.0 million and matured in 2012 to match the principal and maturity of the Senior Notes. Under the swap agreements, we paid a floating rate of interest based on a U.S. Dollar LIBOR rate, plus a spread, and received a fixed rate of interest of 7.625%. These swap agreements were later terminated in 2002 resulting in gains of $44.9 million. The gains realized from the swap terminations have been deferred as adjustments to the carrying value of the Senior Notes and are being amortized using the effective interest method as reductions to future interest expense over the remaining term of the Senior Notes. At December 31, 2005, the unamortized balance of the deferred gains was $32.4 million. In the event of early extinguishment of the Senior Notes, any remaining unamortized gains would be recognized in the consolidated statement of income at the time of extinguishment.

During May 2005, we executed a treasury rate lock agreement with a notional amount of $200.0 million to hedge our exposure to increases in the treasury rate that was to be used to establish the fixed interest rate for a debt offering that was proposed to occur in the second quarter of 2005. During June 2005, the proposed debt offering was cancelled, and the treasury lock was terminated with a realized loss of $2.0 million. The realized loss was recorded as a component of interest expense in the consolidated statements of income in June 2005.

NOTE 5. ACQUISITIONS, DISPOSITIONS AND DISCONTINUED OPERATIONS

Rancho Pipeline

In connection with our acquisition of crude oil assets in 2000, we acquired an approximate 23.5% undivided joint interest in the Rancho Pipeline, which was a crude oil pipeline system from West Texas to Houston, Texas. In March 2003, the Rancho Pipeline ceased operations, and segments of the pipeline were sold to certain of

the owners that previously held undivided interests in the pipeline. We acquired 241 miles of the pipeline in exchange for cash of $5.5 million and our interests in other portions of the Rancho Pipeline. We sold 183 miles of the segment we acquired to other entities for cash and assets valued at approximately $8.5 million. We recorded a net gain of $3.9 million on the transactions in the second quarter of 2003. During the third quarter of 2004, we sold our remaining interest in the original Rancho Pipeline system for a net gain of $0.4 million. These gains are included in the gains on sales of assets in our consolidated statements of income in the 2004 period.

Genesis Pipeline

On November 1, 2003, we purchased crude supply and transportation assets along the upper Texas Gulf Coast for $21.0 million from Genesis Crude Oil, L.P. and Genesis Pipeline Texas, L.P. (“Genesis”). The transaction was funded with proceeds from our August 2003 equity offering (see Note 11). We allocated the purchase price, net of liabilities assumed, primarily to property, plant and equipment and intangible assets. The assets acquired included approximately 150 miles of small diameter trunk lines, 26,000 barrels per day of throughput and 12,000 barrels per day of lease marketing and supply business. We have integrated these assets into our South Texas pipeline system, which has allowed us to consolidate gathering and marketing assets in key operating areas in a cost effective manner and will provide future growth opportunities. Accordingly, the results of the acquisition are included in the consolidated financial statements from November 1, 2003.

The following table allocates the estimated fair value of the Genesis assets acquired on November 1, 2003 (in thousands):

Property, plant and equipment	$ 12,811
Intangible assets	8,742
Other	144
Total assets	21,697
Total liabilities assumed	(687)
Net assets acquired	$ 21,010

Mexia Pipeline

On March 31, 2005, we purchased crude oil pipeline assets for $7.1 million from BP Pipelines (North America) Inc. (“BP”). The assets include approximately 158 miles of pipeline, which extend from Mexia, Texas, to the Houston, Texas, area and two stations in south Houston with connections to a BP pipeline that originates in south Houston. We funded the purchase through borrowings under our revolving credit facility. We allocated the purchase price to property, plant and equipment, and we accounted for the acquisition of these assets under the purchase method of accounting. We have integrated these assets into our South Texas pipeline system, included in our Upstream Segment, which will allow us to realize synergies within our existing asset base and will provide future growth opportunities.

Crude Oil Storage and Terminaling Assets

On April 1, 2005, we purchased crude oil storage and terminaling assets in Cushing, Oklahoma, from Koch Supply & Trading, L.P. for $35.4 million. The assets consist of eight storage tanks with 945,000 barrels of storage capacity, receipt and delivery manifolds, interconnections to several pipelines, crude oil inventory and approximately 70 acres of land. We funded the purchase through borrowings under our revolving credit facility. We allocated the purchase price to property, plant and equipment and inventory, and we accounted for the acquisition of these assets under the purchase method of accounting. The storage and terminaling assets complement our existing infrastructure in Cushing and strengthen our gathering and marketing business in our Upstream Segment.

Refined Products Terminal and Truck Rack

On July 12, 2005, we purchased a refined products terminal and truck loading rack in North Little Rock, Arkansas, for $6.9 million from ExxonMobil Corporation. The assets include three storage tanks and a two-bay truck loading rack. We funded the purchase through borrowings under our revolving credit facility. We allocated the purchase price to property, plant and equipment and inventory, and we accounted for the acquisition of these assets under the purchase method of accounting. The terminal serves the central Arkansas refined products market and complements our existing Downstream Segment infrastructure in North Little Rock, Arkansas.

Genco Assets

On July 15, 2005, we acquired from Texas Genco, LLC (“Genco”) all of its interests in certain companies that own a 90-mile pipeline system and 5.5 million barrels of storage capacity for $62.1 million. We funded the purchase through borrowings under our revolving credit facility. We allocated the purchase price to property, plant and equipment, and we accounted for the acquisition of these assets under the purchase method of accounting. The assets of the purchased companies will be integrated into our Downstream Segment origin infrastructure in Texas City and Baytown, Texas. As a result of this acquisition, we initiated the expansion of refined products origin capabilities in the Houston and Texas City, Texas, areas. The integration and other system enhancements should be in service by the fourth quarter of 2006, at an estimated cost of $45.0 million. The strategic location of these assets, with refined products interconnections to major exchange terminals in the Houston area, will provide significant long-term value to our customers and our Texas Gulf Coast refining and logistics system.

Pioneer Plant

On January 26, 2006, we announced the execution of a letter of intent to sell our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah’s rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise Products Partners L.P. (“Enterprise”). On March 31, 2006, we sold the Pioneer plant to an affiliate of Enterprise for $38.0 million in cash. The Pioneer plant, included in our Midstream Segment, was not an integral part of our operations and natural gas processing is not a core business. The Pioneer plant was constructed as part of the Phase III expansion of the Jonah system and was completed during the first quarter of 2004. We have no continuing involvement in the operations or results of this plant. This transaction was reviewed and approved by the Audit and Conflicts Committee of the board of directors of our General Partner and of the general partner of Enterprise, and a fairness opinion was rendered by an independent third-party.

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the years ended December 31, 2005 and 2004, are presented below (in thousands):

	Years Ended December 31, 2005	2004
Sales of petroleum products	$ 10,479	$ 7,295
Other	2,975	2,807
Total operating revenues	13,454	10,102
Purchases of petroleum products	8,870	5,944
Operating, general and administrative	692	738
Depreciation and amortization	612	610
Taxes — other than income taxes	130	121
Total costs and expenses	10,304	7,413
Income from discontinued operations	$ 3,150	$ 2,689

Assets of the discontinued operations consisted of the following at December 31, 2005 and 2004 (in thousands):

	December 31, 2005	2004
Inventories	$ 7	$ 28
Property, plant and equipment, net	19,812	20,598
Assets of discontinued operations	$ 19,819	$ 20,626

Net cash flows from discontinued operations for the years ended December 31, 2005 and 2004, are presented below (in thousands):

	Years Ended December 31, 2005	2004	2003
Cash flows from discontinued operating activities:			
Net income	$ 3,150	$ 2,689	$ —
Depreciation and amortization	612	610	—
(Increase) decrease in inventories	20	(28)	—
Net cash flows provided by discontinued operating activities	3,782	3,271	—
Cash flows from discontinued investing activities:			
Capital expenditures	—	(7,398)	(13,810)
Net cash flows used in discontinued investing activities	—	(7,398)	(13,810)
Net cash flows from discontinued operations	$ 3,782	$ (4,127)	$ (13,810)

NOTE 6. EQUITY INVESTMENTS

Through one of our indirect wholly owned subsidiaries, we own a 50% ownership interest in Seaway. The remaining 50% interest is owned by ConocoPhillips. We operate the Seaway assets. Seaway owns a pipeline that carries mostly imported crude oil from a marine terminal at Freeport, Texas, to Cushing, Oklahoma, and from a marine terminal at Texas City, Texas, to refineries in the Texas City and Houston, Texas, areas. The Seaway Crude

Pipeline Company Partnership Agreement provides for varying participation ratios throughout the life of Seaway. From June 2002 through May 2006, we receive 60% of revenue and expense of Seaway. Thereafter, we will receive 40% of revenue and expense of Seaway. During the years ended December 31, 2005, 2004 and 2003, we received distributions from Seaway of $24.7 million, $36.9 million and $22.7 million, respectively.

In August 2000, TE Products entered into agreements with Panhandle Eastern Pipeline Company (“PEPL”), a former subsidiary of CMS Energy Corporation, and Marathon Petroleum Company LLC (“Marathon”) to form Centennial. Centennial owns an interstate refined petroleum products pipeline extending from the upper Texas Gulf Coast to central Illinois. Through February 9, 2003, each participant owned a one-third interest in Centennial. On February 10, 2003, TE Products and Marathon each acquired an additional 16.7% interest in Centennial from PEPL for $20.0 million each, increasing their ownership percentages in Centennial to 50% each. During the year ended December 31, 2005, TE Products did not make any additional investments in Centennial. TE Products invested an additional $1.5 million and $24.0 million, respectively, in Centennial, in 2004 and 2003, which is included in the equity investment balance at December 31, 2005. The 2003 amount includes the $20.0 million paid for the acquisition of the additional ownership interest in Centennial. TE Products has not received any distributions from Centennial since its formation.

On January 1, 2003, TE Products and Louis Dreyfus Energy Services L.P. (“Louis Dreyfus”) formed Mont Belvieu Storage Partners, L.P. (“MB Storage”). TE Products and Louis Dreyfus each own a 50% ownership interest in MB Storage. MB Storage owns storage capacity at the Mont Belvieu fractionation and storage complex and a short haul transportation shuttle system that ties Mont Belvieu, Texas, to the upper Texas Gulf Coast energy marketplace. MB Storage is a service-oriented, fee-based venture serving the fractionation, refining and petrochemical industries with substantial capacity and flexibility for the transportation, terminaling and storage of NGLs, LPGs and refined products. MB Storage has no commodity trading activity. TE Products operates the facilities for MB Storage. Effective January 1, 2003, TE Products contributed property and equipment with a net book value of $67.1 million to MB Storage. Additionally, as of the contribution date, Louis Dreyfus had invested $6.1 million for expansion projects for MB Storage that TE Products was required to reimburse if the original joint development and marketing agreement was terminated by either party. This deferred liability was also contributed and credited to the capital account of Louis Dreyfus in MB Storage.

For the year ended December 31, 2005, TE Products received the first $1.7 million per quarter (or $6.78 million on an annual basis) of MB Storage's income before depreciation expense, as defined in the operating agreement. For the year ended December 31, 2004, TE Products received the first $1.8 million per quarter (or $7.15 million on an annual basis) of MB Storage's income before depreciation expense. TE Products' share of MB Storage's earnings is adjusted annually by the partners of MB Storage. Any amount of MB Storage's annual income before depreciation expense in excess of $6.78 million for 2005 and $7.15 million for 2004 was allocated evenly between TE Products and Louis Dreyfus. Depreciation expense on assets each party originally contributed to MB Storage is allocated between TE Products and Louis Dreyfus based on the net book value of the assets contributed. Depreciation expense on assets constructed or acquired by MB Storage subsequent to formation is allocated evenly between TE Products and Louis Dreyfus. For the years ended December 31, 2005, 2004 and 2003, TE Products' sharing ratio in the earnings of MB Storage was 64.2%, 69.4% and 70.4%, respectively. During the years ended December 31, 2005, 2004 and 2003, TE Products received distributions of $12.4 million, $10.3 million and $5.3 million, respectively, from MB Storage. During the years ended December 31, 2005, 2004 and 2003, TE Products contributed $5.6 million, $21.4 million and $2.5 million, respectively, to MB Storage. The 2005 contribution includes a combination of non-cash asset transfers of $1.4 million and cash contributions of $4.2 million. The 2004 contribution includes $16.5 million for the acquisition of storage and pipeline assets in April 2004. The remaining contributions have been for capital expenditures.

We use the equity method of accounting to account for our investments in Seaway, Centennial and MB Storage. Summarized combined financial information for Seaway, Centennial and MB Storage for the years ended December 31, 2005 and 2004, is presented below (in thousands):

	Years Ended December 31, 2005	Years Ended December 31, 2004
Revenues	$ 164,494	$ 149,843
Net income	52,623	52,059

Summarized combined balance sheet information for Seaway, Centennial and MB Storage as of December 31, 2005 and 2004, is presented below (in thousands):

	December 31, 2005	December 31, 2004
Current assets	$ 60,082	$ 59,314
Noncurrent assets	630,212	633,222
Current liabilities	42,242	41,209
Long-term debt	140,000	140,000
Noncurrent liabilities	13,626	20,440
Partners' capital	494,426	490,887

NOTE 7. RELATED PARTY TRANSACTIONS

EPCO and Affiliates and Duke Energy, DEFS and Affiliates

The Partnership does not have any employees. We are managed by the Company, which, for all periods prior to February 23, 2005, was an indirect wholly owned subsidiary of DEFS. According to the Partnership Agreement, the Company was entitled to reimbursement of all direct and indirect expenses related to our business activities. As a result of the change in ownership of the General Partner on February 24, 2005, all of our management, administrative and operating functions are performed by employees of EPCO, pursuant to an administrative services agreement. We reimburse EPCO for the costs of its employees who perform operating functions for us and for costs related to its other management and administrative employees (see Note 1).

The following table summarizes the related party transactions with EPCO and affiliates and DEFS and affiliates for the periods indicated (in millions):

	Years Ended December 31, 2005	2004	2003
Revenues from EPCO and affiliates (1)			
Transportation — NGLs (2)	$ 7.4	$ —	$ —
Transportation — LPGs (3)	4.3	—	—
Other operating revenues (4)	0.3	—	—
Costs and Expenses from EPCO and affiliates (1)			
Payroll and administrative (5)	68.2	—	—
Purchases of petroleum products (6)	3.4	—	—
Revenues from DEFS and affiliates (7)			
Sales of petroleum products (8)	4.3	23.2	15.2

Transportation — NGLs (9)	2.8	16.7	17.2
Gathering — Natural gas — Jonah (10)	0.5	3.3	2.0
Transportation — LPGs (11)	0.7	2.6	2.8
Other operating revenues (12)	2.4	14.0	10.8
Costs and Expenses from DEFS and affiliates (7) (13) (14)			
Payroll and administrative (5)	16.2	95.9	88.8
Purchases of petroleum products — TCO (15)	37.7	141.3	110.7
Purchases of petroleum products — Jonah (16)	0.8	5.1	—

(1) Operating revenues earned and expenses incurred from activities with EPCO and its affiliates are considered related party transactions from February 24, 2005, through December 31, 2005, as a result of the change in ownership of the General Partner (see Note 1).

(2) Includes revenues from NGL transportation on the Chaparral and Panola NGL pipelines.

(3) Includes revenues from LPG transportation on the TE Products pipeline.

(4) Includes other operating revenues on TE Products.

(5) Substantially all of these costs were related to payroll, payroll related expenses and administrative expenses incurred in managing us and our subsidiaries.

(6) Includes TCO purchases of condensate and expenses related to LSI's use of an affiliate of EPCO as a transporter.

(7) Operating revenues earned and expenses incurred from activities with DEFS and its affiliates are considered related party transactions for all periods through February 23, 2005, as a result of the change in ownership of the General Partner (see Note 1).

(8) Includes LSI sales of lubrication oils and specialty chemicals and Jonah NGL sales in connection with Jonah's Pioneer processing plant operations, which was constructed during the Phase III expansion and began operating in 2004. Amounts related to the Pioneer plant are classified as discontinued operations in the consolidated statements of income.

(9) Includes revenues from NGL transportation on the Chaparral, Panola, Dean and Wilcox NGL pipelines.

(10) Includes gas gathering revenues on the Jonah system.

(11) Effective May 2001, we entered into an agreement with an affiliate of DEFS to commit to it sole utilization of our Providence, Rhode Island, terminal. We operate the terminal and provide propane loading services to an affiliate of DEFS. We recognized revenue from an affiliate of DEFS pursuant to this agreement.

(12) Includes fractionation revenues and other revenues. Effective with the purchase of the fractionation facilities on March 31, 1998, TEPPCO Colorado and DEFS entered into a 20-year Fractionation Agreement, under which TEPPCO Colorado receives a variable fee for all fractionated volumes delivered to DEFS. Other operating revenues also include other operating revenues on TE Products and processing and other revenues on the Jonah system. Amounts related to the Pioneer plant are classified as discontinued operations in the consolidated statements of income.

(13) Includes operating costs and expenses related to DEFS managing and operating the Jonah and Val Verde systems and the Chaparral NGL pipeline on our behalf under a contractual agreement established at the time of acquisition of each asset. In connection with the change in ownership of our General Partner, we have assumed these activities.

(14) Effective with the purchase of the fractionation facilities on March 31, 1998, TEPPCO Colorado and DEFS entered into an Operation and Maintenance Agreement, whereby DEFS operates and maintains the fractionation facilities for TEPPCO Colorado. For these services, TEPPCO Colorado pays DEFS a set volumetric rate for all fractionated volumes delivered to DEFS.

(15) Includes TCO purchases of condensate.

(16) Includes Jonah purchases of natural gas in connection with Jonah's Pioneer processing plant operations.

At December 31, 2005, we had a receivable from EPCO and affiliates of $4.3 million related to sales and transportation services provided to EPCO and affiliates. At December 31, 2005, we had a payable to EPCO and affiliates of $9.8 million related to direct payroll, payroll related costs and other operational related charges.

At December 31, 2004, we had a receivable from DEFS and affiliates of $10.5 million related to sales and transportation services provided to DEFS and affiliates. Included in this receivable balance from DEFS and affiliates at December 31, 2004, is a gas imbalance receivable of $0.9 million. At December 31, 2004, we had a payable to DEFS and affiliates of $22.4 million related to direct payroll, payroll related costs, management fees, and other operational related charges, including those for Jonah, Chaparral and Val Verde as described above. Included in this payable balance at December 31, 2004, is a gas imbalance payable to DEFS and affiliates of $3.2 million.

From February 24, 2005 through December 31, 2005, the majority of our insurance coverage, including property, liability, business interruption, auto and directors and officers' liability insurance, was obtained through EPCO. From February 24, 2005 through December 31, 2005, we incurred insurance expense related to premiums charged by EPCO of $9.8 million. At December 31, 2005, we had insurance reimbursement receivables due from EPCO of $1.3 million.

Through February 23, 2005, we contracted with Bison Insurance Company Limited (“Bison”), a wholly owned subsidiary of Duke Energy, for a majority of our insurance coverage, including property, liability, auto and directors and officers’ liability insurance. Through February 23, 2005 and for the years ended December 31, 2004 and 2003, we incurred insurance expense related to premiums paid to Bison of $1.2 million, $6.5 million and $5.9 million, respectively. At December 31, 2004, we had insurance reimbursement receivables due from Bison of $5.2 million.

On April 2, 2003, we sold in an underwritten public offering 3.9 million Units at $30.35 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $114.5 million, of which approximately $113.8 million was used to repurchase and retire all of the 3.9 million previously outstanding Class B Units held by DETTCO (see Note 11).

Seaway

We own a 50% ownership interest in Seaway, and the remaining 50% interest is owned by ConocoPhillips (see Note 6). We operate the Seaway assets. During the years ended December 31, 2005, 2004 and 2003, we billed Seaway $8.5 million, $7.6 million and $7.4 million, respectively, for direct payroll and payroll related expenses for operating Seaway. Additionally, for each of the years ended December 31, 2005, 2004 and 2003, we billed Seaway $2.1 million for indirect management fees for operating Seaway. At December 31, 2005 and 2004, we had payable balances to Seaway of $0.6 million and $0.5 million, respectively, for advances Seaway paid to us as operator for operating costs, including payroll and related expenses and management fees.

Centennial

TE Products has a 50% ownership interest in Centennial (see Note 6). TE Products has entered into a management agreement with Centennial to operate Centennial’s terminal at Creal Springs, Illinois, and pipeline connection in Beaumont, Texas. For each of the years ended December 31, 2005, 2004 and 2003, we recognized management fees of $0.2 million from Centennial, and actual operating expenses billed to Centennial were $3.7 million, $6.9 million and $4.4 million, respectively.

TE Products also has a joint tariff with Centennial to deliver products at TE Products’ locations using Centennial’s pipeline as part of the delivery route to connecting carriers. TE Products, as the delivering pipeline, invoices the shippers for the entire delivery rate, records only the net rate attributable to it as transportation revenues and records a liability for the amounts due to Centennial for its share of the tariff. In addition, TE Products performs ongoing construction services for Centennial and bills Centennial for labor and other costs to perform the construction. At December 31, 2005 and 2004, we had net payable balances of $1.4 million and $1.7 million, respectively, to Centennial for its share of the joint tariff deliveries and other operational related charges, partially offset by the reimbursement due to us for construction services provided to Centennial.

In January 2003, TE Products entered into a pipeline capacity lease agreement with Centennial for a period of five years that contains a minimum throughput requirement. For the years ended December 31, 2005, 2004 and 2003, TE Products incurred $5.9 million, $5.3 million and $3.8 million, respectively, of rental charges related to the lease of pipeline capacity on Centennial.

MB Storage

Effective January 1, 2003, TE Products entered into agreements with Louis Dreyfus to form MB Storage (see Note 6). TE Products operates the facilities for MB Storage. TE Products and MB Storage have entered into a pipeline capacity lease agreement, and for each of the years ended December 31, 2005, 2004 and 2003, TE Products recognized $0.1 million in rental revenue related to this lease agreement. During the years ended December 31, 2005, 2004 and 2003, TE Products also billed MB Storage $3.6 million, $3.2 million and $2.5 million, respectively, for direct payroll and payroll related expenses for operating MB Storage. At December 31, 2005 and 2004, TE Products had net receivable balances from MB Storage of $0.9 million and $1.3 million, respectively, for operating costs, including payroll and related expenses for operating MB Storage.

NOTE 8. INVENTORIES

Inventories are valued at the lower of cost (based on weighted average cost method) or market. The costs of inventories did not exceed market values at December 31, 2005 and 2004. The major components of inventories were as follows (in thousands):

	December 31, 2005	December 31, 2004
Crude oil	$ 3,021	$ 3,690
Refined products	4,461	5,665
LPGs	7,403	—
Lubrication oils and specialty chemicals	5,740	4,002
Materials and supplies	8,203	6,135
Other	241	29
Total	$ 29,069	$ 19,521

NOTE 9. PROPERTY, PLANT AND EQUIPMENT

Major categories of property, plant and equipment for the years ended December 31, 2005 and 2004, were as follows (in thousands):

	December 31, 2005	December 31, 2004

Land and right of way	$ 147,064	$ 135,984
Line pipe and fittings	1,434,392	1,344,193
Storage tanks	189,054	140,690
Buildings and improvements	51,596	41,205
Machinery and equipment	370,439	333,363
Construction work in progress	241,855	115,937
Total property, plant and equipment	$ 2,434,400	$ 2,111,372
Less accumulated depreciation and amortization	474,332	407,670
Net property, plant and equipment	$ 1,960,068	$ 1,703,702

Depreciation expense, including impairment charges, on property, plant and equipment was $80.8 million, $80.7 million and $64.5 million for the years ended December 31, 2005, 2004 and 2003, respectively. During the fourth quarter of 2004, we wrote off approximately $2.1 million in assets taken out of service to depreciation expense.

In September 2005, our Todhunter facility, near Middletown, Ohio, experienced a propane release and fire at a dehydration unit within the storage facility. The facility is included in our Downstream Segment. The dehydration unit was destroyed due to the propane release and fire, and as a result, we wrote off the remaining book value of the asset of $0.8 million to depreciation and amortization expense during the third quarter of 2005.

We evaluate impairment of long-lived assets in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. During the third quarter of 2005, our Upstream Segment was notified by a connecting carrier that the flow of its pipeline system would be reversed, which would directly impact the viability of one of our pipeline systems. This system, located in East Texas, consists of approximately 45 miles of pipeline, six tanks of various sizes and other equipment and asset costs. As a result of changes to the connecting carrier, we performed an impairment test of the system and recorded a $1.8 million non-cash impairment charge, included in depreciation and amortization expense in our consolidated statements of income, for the excess carrying value over the estimated fair value of the system.

During the third quarter of 2005, we completed an evaluation of a crude oil system included in our Upstream Segment. The system, located in Oklahoma, consists of approximately six miles of pipelines, tanks and other equipment and asset costs. The usage of the system has declined in recent months as a result of shifting crude oil production into areas not supported by the system, and as such, it has become more economical to transport barrels by truck to our other pipeline systems. As a result, we performed an impairment test on the system and recorded a $0.8 million non-cash impairment charge, included in depreciation and amortization expense in our consolidated statements of income, for the excess carrying value over the estimated fair value of the system.

During the third quarter of 2004, we completed an evaluation of our marine terminal facility in the Beaumont, Texas, area. The facility consists primarily of a barge dock, a ship dock, four storage tanks and various segments of connecting pipelines and is included in our Downstream Segment. The evaluation indicated that the docks and other assets at the facility needed extensive work to continue to be commercially operational. As a result, we performed an impairment test on the entire marine facility and recorded a $4.4 million non-cash impairment charge, included in depreciation and amortization expense in our consolidated statements of income, for the excess carrying value over the estimated fair value of the facility.

NOTE 10. DEBT

Senior Notes

On January 27, 1998, TE Products completed the issuance of $180.0 million principal amount of 6.45% Senior Notes due 2008, and $210.0 million principal amount of 7.51% Senior Notes due 2028 (collectively the "TE Products Senior Notes"). The 6.45% TE Products Senior Notes were issued at a discount of $0.3 million and are being accreted to their face value over the term of the notes. The 6.45% TE Products Senior Notes due 2008 are not subject to redemption prior to January 15, 2008. The 7.51% TE Products Senior Notes due 2028, issued at par, may be redeemed at any time after January 15, 2008, at the option of TE Products, in whole or in part, at our election at the following redemption prices (expressed in percentages of the principal amount) if redeemed during the twelve months beginning January 15 of the years indicated:

Year	Redemption Price	Year	Redemption Price
2008	103.755%	2013	101.878%
2009	103.380%	2014	101.502%
2010	103.004%	2015	101.127%
2011	102.629%	2016	100.751%
2012	102.253%	2017	100.376%

and thereafter at 100% of the principal amount, together in each case with accrued interest at the redemption date.

The TE Products Senior Notes do not have sinking fund requirements. Interest on the TE Products Senior Notes is payable semiannually in arrears on January 15 and July 15 of each year. The TE Products Senior Notes are unsecured obligations of TE Products and rank pari passu with all other unsecured and unsubordinated indebtedness of TE Products. The indenture governing the TE Products Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2005, TE Products was in compliance with the covenants of the TE Products Senior Notes.

On February 20, 2002, we completed the issuance of $500.0 million principal amount of 7.625% Senior Notes due 2012. The 7.625% Senior Notes were issued at a discount of $2.2 million and are being accreted to their face value over the term of the notes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 7.625% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2005, we were in compliance with the covenants of these Senior Notes.

On January 30, 2003, we completed the issuance of $200.0 million principal amount of 6.125% Senior Notes due 2013. The 6.125% Senior Notes were issued at a discount of $1.4 million and are being accreted to their face value over the term of the notes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 6.125% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2005, we were in compliance with the covenants of these Senior Notes.

The following table summarizes the estimated fair values of the Senior Notes as of December 31, 2005 and 2004 (in millions):

	Face Value	Fair Value December 31, 2005	Fair Value December 31, 2004
6.45% TE Products Senior Notes, due January 2008	$ 180.0	$ 183.7	$ 187.1
7.625% Senior Notes, due February 2012	500.0	552.0	569.6
6.125% Senior Notes, due February 2013	200.0	205.6	210.2
7.51% TE Products Senior Notes, due January 2028	210.0	224.1	225.6

We have entered into interest rate swap agreements to hedge our exposure to changes in the fair value on a portion of the Senior Notes discussed above (see Note 4).

Revolving Credit Facility

On April 6, 2001, we entered into a $500.0 million revolving credit facility including the issuance of letters of credit of up to $20.0 million ("Three Year Facility"). The interest rate was based, at our option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. The credit agreement for the Three Year Facility contained certain restrictive financial covenant ratios. During the first quarter of 2003, we repaid $182.0 million of the outstanding balance of the Three Year Facility with proceeds from the issuance of our 6.125% Senior Notes on January 30, 2003. On June 27, 2003, we repaid the outstanding balance under the Three Year Facility with borrowings under a new credit facility, and canceled the Three Year Facility.

On June 27, 2003, we entered into a $550.0 million unsecured revolving credit facility with a three year term, including the issuance of letters of credit of up to $20.0 million ("Revolving Credit Facility"). The interest rate is based, at our option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. The credit agreement for the Revolving Credit Facility contains certain restrictive financial covenant ratios. Restrictive covenants in the Revolving Credit Facility limit our ability to, among other things, incur additional indebtedness, make distributions in excess of Available Cash (see Note 11) and complete mergers, acquisitions and sales of assets. We borrowed $263.0 million under the Revolving Credit Facility and repaid the outstanding balance of the Three Year Facility. On October 21, 2004, we amended our Revolving Credit Facility to (i) increase the facility size to $600.0 million, (ii) extend the term to October 21, 2009, (iii) remove certain restrictive covenants, (iv) increase the available amount for the issuance of letters of credit up to $100.0 million and (v) decrease the LIBOR rate spread charged at the time of each borrowing. On February 23, 2005, we amended our Revolving Credit Facility to remove the requirement that DEFS must at all times own, directly or indirectly, 100% of our General Partner, to allow for its acquisition by DFI (see Note 1). During the second quarter of 2005, we used a portion of the proceeds from the equity offering in May 2005 to repay a portion of the Revolving Credit Facility (see Note 11). On December 13, 2005, we again amended our Revolving Credit Facility as follows:

- Total bank commitments increased from $600.0 million to $700.0 million. The amendment also provided that the commitments under the credit facility may be increased up to a maximum of $850.0 million upon our request, subject to lender approval and the satisfaction of certain other conditions.
- The facility fee and the borrowing rate currently in effect were reduced by 0.275%.
- The maturity date of the credit facility was extended from October 21, 2009, to December 13, 2010. Also under the terms of the amendment, we may request up to two, one-year extensions of the maturity date. These extensions, if requested, will become effective subject to lender approval and satisfaction of certain other conditions.
- The amendment also removed the $100.0 million limit on the total amount of standby letters of credit that can be outstanding under the credit facility.

On December 31, 2005, $405.9 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 4.9%. At December 31, 2005, we were in compliance with the covenants of this credit agreement.

The following table summarizes the principal amounts outstanding under all of our credit facilities as of December 31, 2005 and 2004 (in thousands):

	December 31, 2005	December 31, 2004
Credit Facilities:		
Revolving Credit Facility, due December 2010	$ 405,900	$ 353,000

6.45% TE Products Senior Notes, due January 2008	179,937	179,906
7.625% Senior Notes, due February 2012	498,659	498,438
6.125% Senior Notes, due February 2013	198,988	198,845
7.51% TE Products Senior Notes, due January 2028	210,000	210,000
Total borrowings	1,493,484	1,440,189
Adjustment to carrying value associated with hedges of fair value	31,537	40,037
Total Credit Facilities	$ 1,525,021	$ 1,480,226

Letter of Credit

At December 31, 2005, we had an $11.5 million standby letter of credit in connection with crude oil purchases in the fourth quarter of 2005. This amount will be paid during the first quarter of 2006.

NOTE 11. PARTNERS' CAPITAL AND DISTRIBUTIONS

Equity Offerings

On April 2, 2003, we sold in an underwritten public offering 3.9 million Units at $30.35 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $114.5 million, of which approximately $113.8 million was used to repurchase and retire all of the 3.9 million previously outstanding Class B Units held by DETTCO. We received approximately $0.7 million in proceeds from the offering in excess of the amount needed to repurchase and retire the Class B Units.

On August 7, 2003, we sold in an underwritten public offering 5.0 million Units at $34.68 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $166.0 million. On August 19, 2003, 162,900 Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering on August 7, 2003. Proceeds from the over-allotment sale, net of underwriting discount, totaled $5.4 million. Approximately $53.0 million of the proceeds were used to repay indebtedness under our revolving credit facility and $21.0 million was used to fund the acquisition of the Genesis assets (see Note 5). The remaining amount was used primarily to fund revenue-generating and system upgrade capital expenditures and for general partnership purposes.

On May 5, 2005, we sold in an underwritten public offering 6.1 million Units at $41.75 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $244.5 million. On June 8, 2005, 865,000 Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering on May 5, 2005. Proceeds from the over-allotment sale, net of underwriting discount, totaled $34.7 million. The proceeds were used to reduce indebtedness under our Revolving Credit Facility, to fund revenue generating and system upgrade capital expenditures and for general partnership purposes.

Quarterly Distributions of Available Cash

We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. Pursuant to the Partnership Agreement, the General Partner receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds as follows:

	Unitholders	General Partner
Quarterly Cash Distribution per Unit:		
Up to Minimum Quarterly Distribution ($0.275 per Unit)	98%	2%
First Target - $0.276 per Unit up to $0.325 per Unit	85%	15%
Second Target - $0.326 per Unit up to $0.45 per Unit	75%	25%
Over Second Target - Cash distributions greater than $0.45 per Unit	50%	50%

The following table reflects the allocation of total distributions paid during the years ended December 31, 2005, 2004 and 2003 (in thousands, except per Unit amounts):

	Years Ended December 31, 2005	2004	2003
Limited Partner Units	$ 177,917	$ 166,158	$ 145,427
General Partner Ownership Interest	3,630	3,391	3,016
General Partner Incentive	69,554	63,508	51,709
Total Partners' Capital Cash Distributions Paid	251,101	233,057	200,152
Class B Units	—	—	2,346
Total Cash Distributions Paid	$ 251,101	$ 233,057	$ 202,498
Total Cash Distributions Paid Per Unit	$ 2.68	$ 2.64	$ 2.50

On February 7, 2006, we paid a cash distribution of $0.675 per Unit for the quarter ended December 31, 2005. The fourth quarter 2005 cash distribution totaled $66.9 million.

General Partner Interest

As of December 31, 2005 and 2004, we had deficit balances of $61.5 million and $35.9 million, respectively, in our General Partner's equity account. These negative balances do not represent an asset to us and do not represent an obligation of the General Partner to contribute cash or other property to us. The General Partner's equity account generally consists of its cumulative share of our net income less cash distributions made to it plus capital contributions that it has made to us (see our Consolidated Statements of Partners' Capital for a detail of the General Partner's equity account). For the years ended December 31, 2005, 2004 and 2003, the General Partner was allocated $47.6 million (representing 29.27%), $40.0 million (representing 28.85%) and $33.7 million (representing 27.65%), respectively, of our net income and received $73.2 million, $66.9 million and $54.7 million, respectively, in cash distributions.

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 accounting principles generally accepted in the United States in our financial statements. Under our Partnership Agreement, the General Partner is required to make additional capital contributions to us upon the issuance of any additional Units if necessary to maintain a Capital Account balance equal to 1.999999% of the total Capital Accounts of all partners. At December 31, 2005 and 2004, the General Partner's Capital Account balance substantially exceeded this requirement.

Net income is allocated between the General Partner and the limited partners in the same proportion as aggregate cash distributions made to the General Partner and the limited partners during the period. This is generally consistent with the manner of allocating net income under our Partnership Agreement. Net income determined under our Partnership Agreement, however, incorporates principles established for U.S. federal income tax purposes and is not comparable to net income reflected under accounting principles generally accepted in the United States in our financial statements.

Cash distributions that we make during a period may exceed our net income for the period. We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. Cash distributions in excess of net income allocations and capital contributions during the years ended December 31, 2005 and 2004, resulted in a deficit in the General Partner's equity account at December 31, 2005 and 2004. Future cash distributions that exceed net income will result in an increase in the deficit balance in the General Partner's equity account.

According to the Partnership Agreement, in the event of our dissolution, after satisfying our liabilities, our remaining assets would be divided among our limited partners and the General Partner generally in the same proportion as Available Cash but calculated on a cumulative basis over the life of the Partnership. If a deficit balance still remains in the General Partner's equity account after all allocations are made between the partners, the General Partner would not be required to make whole any such deficit.

NOTE 12. CONCENTRATIONS OF CREDIT RISK

Our primary market areas are located in the Northeast, Midwest and Southwest regions of the United States. We have a concentration of trade receivable balances due from major integrated oil companies, independent oil companies and other pipelines and wholesalers. These concentrations of customers may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. We thoroughly analyze our customers' historical and future credit positions prior to extending credit. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments and guarantees.

For each of the years ended December 31, 2005, 2004 and 2003, Valero Energy Corp. accounted for 14%, 16% and 16% of our total consolidated revenues, respectively. No other single customer accounted for 10% or more of our total consolidated revenues for the years ended December 31, 2005, 2004 and 2003.

The carrying amount of cash and cash equivalents, accounts receivable, inventories, other current assets, accounts payable and accrued liabilities, other current liabilities and derivatives approximates their fair value due to their short-term nature.

NOTE 13. UNIT-BASED COMPENSATION

1994 Long Term Incentive Plan

During 1994, the Company adopted the Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan ("1994 LTIP"). The 1994 LTIP provides certain key employees with an incentive award whereby a participant is granted an option to purchase Units. These same employees are also granted a stipulated number of Performance Units, the cash value of which may be used to pay for the exercise of the respective Unit options awarded. Under the provisions of the 1994 LTIP, no more than one million options and two million Performance Units may be granted.

When our calendar year earnings per unit (exclusive of certain special items) exceeds a stated threshold, each participant receives a credit to their respective Performance Unit account equal to the earnings per unit excess multiplied by the number of Performance Units awarded. The balance in the Performance Unit account may be used to offset the cost of exercising Unit options granted in connection with the Performance Units or may be withdrawn two years after the underlying options expire, usually 10 years from the date of grant. Any unused balance previously credited is forfeited upon termination. We accrue compensation expense for the Performance Units awarded annually based upon the terms of the plan discussed above.

Under the agreement for such Unit options, the options become exercisable in equal installments over periods of one, two, and three years from the date of the grant. At December 31, 2005, all options have been fully exercised. The Performance Unit account has a minimal liability balance which may be withdrawn by the participants after December 31, 2006.

A summary of Unit options granted under the terms of the 1994 LTIP is presented below:

	Options Outstanding	Options Exercisable	Exercise Range

Unit Options:			
Outstanding at December 31, 2002	90,091	90,091	$ 13.81 - $25.69
Exercised	(90,091)	(90,091)	$ 13.81 - $25.69
Outstanding at December 31, 2003	—	—	

We have not granted options for any periods presented. During the year ended December 31, 2003, all remaining outstanding Unit options were exercised. For options previously outstanding, we followed the intrinsic value method for recognizing stock-based compensation expense. The exercise price of all options awarded under the 1994 LTIP equaled the market price of our Units on the date of grant. Accordingly, we recognized no compensation expense at the date of grant. Had compensation expense been determined consistent with SFAS No. 123, *Accounting for Stock-Based Compensation*, no compensation expense would have been recognized for the years ended December 31, 2005, 2004 and 2003.

1999 and 2002 Phantom Unit Plans

Effective September 1, 1999, the Company adopted the Texas Eastern Products Pipeline Company, LLC 1999 Phantom Unit Retention Plan ("1999 PURP"). Effective June 1, 2002, the Company adopted the Texas Eastern Products Pipeline Company, LLC 2002 Phantom Unit Retention Plan ("2002 PURP"). The 1999 PURP and the 2002 PURP provide key employees with incentive awards whereby a participant is granted phantom units. These phantom units are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at stated redemption dates. The fair market value of each phantom unit is equal to the closing price of a Unit as reported on the New York Stock Exchange on the redemption date.

Under the agreement for the phantom units, each participant will vest 10% of the number of phantom units initially granted under his or her award at the end of each of the first four years and will vest the final 60% at the end of the fifth year. Each participant is required to redeem their phantom units as they vest. They are also entitled to quarterly cash distributions equal to the product of the number of phantom units outstanding for the participant and the amount of the cash distribution that we paid per Unit to unitholders. We accrued compensation expense annually based upon the terms of the 1999 PURP and 2002 PURP discussed above. At December 31, 2004, we had an accrued liability balance of $1.6 million for compensation related to the 1999 PURP and 2002 PURP. Due to a change of ownership as a result of the sale of our General Partner on February 24, 2005 (see Note 1), all outstanding units under both the 1999 PURP and the 2002 PURP fully vested and were redeemed by participants. As such, there were no outstanding units at December 31, 2005 under either the 1999 PURP or the 2002 PURP.

2000 Long Term Incentive Plan

Effective January 1, 2000, the General Partner established the Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan ("2000 LTIP") to provide key employees incentives to achieve improvements in our financial performance. Generally, upon the close of a three-year performance period, if the participant is then still an employee of the General Partner, the participant will receive a cash payment in an amount equal to (1) the applicable performance percentage specified in the award multiplied by (2) the number of phantom units granted under the award multiplied by (3) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. Generally, a participant's performance percentage is based upon the improvement of our Economic Value Added (as defined below) during a three-year performance period over the Economic Value Added during the three-year period immediately preceding the performance period. If a participant incurs a separation from service during the performance period due to death, disability or retirement (as such terms are defined in the 2000 LTIP), the participant will be entitled to receive a cash payment in an amount equal to the amount computed as described above multiplied by a fraction, the numerator of which is the number of days that have elapsed during the performance period prior to the participant's separation from service and the denominator of which is the number of days in the performance period. Due to a change of ownership as a result of the sale of our General Partner on February 24, 2005, all outstanding units under the 2000 LTIP for plan years 2003 and 2004 were fully vested and redeemed by participants. As such, there were no outstanding units at December 31, 2005, for awards granted for the plan years ended December 31, 2004 and 2003. At December 31, 2005, phantom units outstanding for awards granted for the plan year ended December 31, 2005, were 23,400.

Economic Value Added means our average annual EBITDA for the performance period minus the product of our average asset base and our cost of capital for the performance period. For purposes of the 2000 LTIP for plan years 2000 through 2002, EBITDA means our earnings before net interest expense, depreciation and amortization and our proportional interest in EBITDA of our joint ventures as presented in our consolidated financial statements prepared in accordance with generally accepted accounting principles, except that at his discretion the Chief Executive Officer ("CEO") of the Company may exclude gains or losses from extraordinary, unusual or non-recurring items. For the years ended December 31, 2005, 2004 and 2003, EBITDA means, in addition to the above definition of EBITDA, earnings before other income — net. Average asset base means the quarterly average, during the performance period, of our gross value of property, plant and equipment, *plus* products and crude oil operating oil supply and the gross value of intangibles and equity investments. Our cost of capital is approved by our CEO at the date of award grant.

In addition to the payment described above, during the performance period, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under this award. We accrue compensation expense annually based upon the terms of the 2000 LTIP discussed above. At December 31, 2005 and 2004, we had an accrued liability balance of $0.7 million and $2.4 million, respectively, for compensation related to the 2000 LTIP.

2005 Phantom Unit Plan

Effective January 1, 2005, the Company adopted the Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan ("2005 PURP") to provide key employees incentives to achieve improvements in our financial performance. Generally, upon the close of a three-year performance period, if the participant is then still an employee of the General Partner, the participant will receive a cash payment in an amount equal to (1) the grantee's vested percentage multiplied by (2) the number of phantom units granted under the award multiplied by (3) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. Generally, a participant's vested percentage is based upon the improvement of our EBITDA (as defined below) during a three-year performance period over the target EBITDA as defined at the beginning of each year during the three-year performance period. EBITDA means our earnings before minority interest, net interest expense, other income — net, income taxes, depreciation and amortization and our proportional interest in EBITDA of our joint ventures as presented in our consolidated financial statements prepared in accordance with generally accepted accounting principles, except that at his discretion, our CEO may exclude gains or losses from extraordinary, unusual or non-recurring items. At December 31, 2005, phantom units outstanding for awards granted for the plan year ended December 31, 2005, were 53,600.

In addition to the payment described above, during the performance period, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under this award. We accrue compensation expense annually based upon the terms of the 2005 PURP discussed above. At December 31, 2005, we had an accrued liability balance of $0.7 million for compensation related to the 2005 PURP.

NOTE 14. OPERATING LEASES

We use leased assets in several areas of our operations. Total rental expense for the years ended December 31, 2005, 2004 and 2003, was $24.0 million, $22.1 million and $18.8 million, respectively. The following table sets forth our minimum rental payments under our various operating leases for the years ending December 31 (in thousands):

2006	$ 19,536
2007	17,391
2008	10,863
2009	7,682
2010	6,645
Thereafter	21,544
	$ 83,661

NOTE 15. EMPLOYEE BENEFITS

Retirement Plans

The TEPPCO Retirement Cash Balance Plan ("TEPPCO RCBP") was a non-contributory, trustee-administered pension plan. In addition, the TEPPCO Supplemental Benefit Plan ("TEPPCO SBP") was a non-contributory, nonqualified, defined benefit retirement plan, in which certain executive officers participated. The TEPPCO SBP was established to restore benefit reductions caused by the maximum benefit limitations that apply to qualified plans. The benefit formula for all eligible employees was a cash balance formula. Under a cash balance formula, a plan participant accumulated a retirement benefit based upon pay credits and current interest credits. The pay credits were based on a participant's salary, age and service. We used a December 31 measurement date for these plans.

On May 27, 2005, the TEPPCO RCBP and the TEPPCO SBP were amended. Effective May 31, 2005, participation in the TEPPCO RCBP was frozen, and no new participants were eligible to be covered by the plan after that date. Effective December 31, 2005, all plan benefits accrued were frozen, participants will not receive additional pay credits after that date, and all plan participants were 100% vested regardless of their years of service. The TEPPCO RCBP plan was terminated effective December 31, 2005, subject to IRS approval of plan termination, and plan participants will have the option to receive their benefits either through a lump sum payment in 2006 or through an annuity. For those plan participants who elect to receive an annuity, we will purchase an annuity contract from an insurance company in which the plan participant owns the annuity, absolving us of any future obligation to the participant. Participants in the TEPPCO SBP received pay credits through November 30, 2005, and received lump sum benefit payments in December 2005. Both the RCBP and SBP benefit payments are discussed below.

In June 2005, we recorded a curtailment charge of $0.1 million in accordance with SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, as a result of the TEPPCO RCBP and TEPPCO SBP amendments. As of May 31, 2005, the following assumptions were changed for purposes of determining the net periodic benefit costs for the remainder of 2005: the discount rate, the long-term rate of return on plan assets, and the assumed mortality table. The discount rate was decreased from 5.75% to 5.00% to reflect rates of returns on bonds currently available to settle the liability. The expected long-term rate of return on plan assets was changed from 8% to 2% due to the movement of plan funds from equity investments into short-term money market funds. The mortality table was changed to reflect overall improvements in mortality experienced by the general population. The curtailment charge arose due to the accelerated recognition of the unrecognized prior service costs. We recorded additional settlement charges of approximately $0.2 million in the fourth quarter of 2005 relating to the TEPPCO SBP. We expect to record additional settlement charges of approximately $4.0 million in 2006 relating to the TEPPCO RCBP for any existing unrecognized losses upon the plan termination and final distribution of the assets to the plan participants.

The components of net pension benefits costs for the TEPPCO RCBP and the TEPPCO SBP for the years ended December 31, 2005, 2004 and 2003, were as follows (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Service cost benefit earned during the year	$4,393	$ 3,653	$ 3,179
Interest cost on projected benefit obligation	934	719	504
Expected return on plan assets	(671)	(878)	(604)
Amortization of prior service cost	5	7	7
Recognized net actuarial loss	129	57	24
SFAS 88 curtailment charge	50	—	—

SFAS 88 settlement charge	194	—	—
Net pension benefits costs	$5,034	$ 3,558	$ 3,110

Other Postretirement Benefits

We provided certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis ("TEPPCO OPB"). Employees became eligible for these benefits if they met certain age and service requirements at retirement, as defined in the plans. We provided a fixed dollar contribution, which did not increase from year to year, towards retired employee medical costs. The retiree paid all health care cost increases due to medical inflation. We used a December 31 measurement date for this plan.

In May 2005, benefits provided to employees under the TEPPCO OPB were changed. Employees eligible for these benefits received them through December 31, 2005, however, effective December 31, 2005, these benefits were terminated. As a result of this change in benefits and in accordance with SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, we recorded a curtailment credit of approximately $1.7 million in our accumulated postretirement obligation which reduced our accumulated postretirement obligation to the total of the expected remaining 2005 payments under the TEPPCO OPB. The current employees participating in this plan were transferred to DEFS, who will continue to provide postretirement benefits to these retirees. We recorded a one-time settlement to DEFS in the third quarter of 2005 of $0.4 million for the remaining postretirement benefits.

The components of net postretirement benefits cost for the TEPPCO OPB for the years ended December 31, 2005, 2004 and 2003, were as follows (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Service cost benefit earned during the year	$ 81	$ 165	$ 137
Interest cost on accumulated postretirement benefit obligation	69	153	137
Amortization of prior service cost	53	126	126
Recognized net actuarial loss	4	1	—
Curtailment credit	(1,676)	—	—
Settlement credit	(4)	—	—
Net postretirement benefits costs	$ (1,473)	$ 445	$ 400

Effective June 1, 2005, the payroll functions performed by DEFS for our General Partner were transferred from DEFS to EPCO. For those employees who were receiving certain other postretirement benefits at the time of the acquisition of our General Partner by DFI, DEFS will continue to provide these benefits to those employees. Effective June 1, 2005, EPCO began providing certain other postretirement benefits to those employees who became eligible for the benefits after June 1, 2005, and will charge those benefit related costs to us. As a result of these changes, we recorded a $1.2 million reduction in our other postretirement obligation in June 2005.

We employed a building block approach in determining the long-term rate of return for plan assets. Historical markets were studied and long-term historical relationships between equities and fixed-income were preserved consistent with a widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates were evaluated before long-term capital market assumptions were determined. The long-term portfolio return was established via a building block approach with proper consideration of diversification and rebalancing. Peer data and historical returns were reviewed to check for reasonability and appropriateness.

The weighted average assumptions used to determine benefit obligations for the retirement plans and other postretirement benefit plans at December 31, 2005 and 2004, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Discount rate	4.59%	5.75%	5.75%	5.75%
Increase in compensation levels	—	5.00%	—	—

The weighted average assumptions used to determine net periodic benefit cost for the retirement plans and other postretirement benefit plans for the years ended December 31, 2005 and 2004, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Discount rate (1)	5.75%/5.00%	6.25%	5.75%/5.00%	6.25%
Increase in compensation levels	5.00%	5.00%	—	—
Expected long-term rate of return on plan assets (2)	8.00%/2.00%	8.00%	—	—

(1) Expense was remeasured on May 31, 2005, as a result of TEPPCO RCBP and TEPPCO SBP amendments. The discount rate was decreased from 5.75% to 5% effective June 1, 2005, to reflect rates of returns on bonds currently available to settle the liability.

(2) As a result of TEPPCO RCBP and TEPPCO SBP amendments, the expected return on assets was changed from 8% to 2% due to the movement of plan funds from equity investments into short-term money market funds, effective June 1, 2005.

The following table sets forth our pension and other postretirement benefits changes in benefit obligation, fair value of plan assets and funded status as of December 31, 2005 and 2004 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Change in benefit obligation				
Benefit obligation at beginning of year	$ 15,940	$ 11,256	$ 2,964	$ 2,467
Service cost	4,393	3,653	81	165
Interest cost	934	719	70	153
Actuarial loss	2,740	572	76	205
Retiree contributions	—	—	64	60
Benefits paid	(910)	(260)	(80)	(86)
Impact of curtailment	(986)	—	(3,575)	—
Settlement	—	—	400	—
Benefit obligation at end of year	$ 22,111	$ 15,940	$ —	$ 2,964
Change in plan assets				
Fair value of plan assets at beginning of year	$ 14,969	$ 10,921	$ —	$ —
Actual return on plan assets	20	808	—	—
Retiree contributions	—	—	64	60
Employer contributions	9,025	3,500	16	26
Benefits paid	(910)	(260)	(80)	(86)
Fair value of plan assets at end of year	$ 23,104	$ 14,969	$ —	$ —
Reconciliation of funded status				
Funded status	$ 994	$ (971)	$ —	$ (2,964)
Unrecognized prior service cost	—	33	—	1,003
Unrecognized actuarial loss	4,067	2,006	—	472
Net amount recognized	$ 5,061	$ 1,068	$ —	$ (1,489)

We estimate the following benefit payments, which reflect expected future service, as appropriate, will be paid (in thousands):

	Pension Benefits	Other Postretirement Benefits
2006	$ 22,360	$ —

Plan Assets

We employed a total return investment approach whereby a mix of equities and fixed income investments were used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance was established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contained a diversified blend of equity and fixed-income investments. Furthermore, equity investments were diversified across U.S. and non-U.S. stocks, both growth and value equity style, and small, mid and large capitalizations. Investment risk and return parameters were reviewed and evaluated periodically to ensure compliance with stated investment objectives and guidelines. This comprehensive review incorporated investment portfolio performance, annual liability measurements and periodic asset/liability studies.

The following table sets forth the weighted average asset allocations for the retirement plans and other postretirement benefit plans as of December 31, 2005 and 2004, by asset category (in thousands):

Asset Category	December 31, 2005	December 31, 2004
Equity securities	—	63%
Debt securities	—	35%
Other (money market and cash)	100%	2%
Total	100%	100%

We do not expect to make further contributions to our retirement plans and other postretirement benefit plans in 2006.

Other Plans

DEFS also sponsored an employee savings plan, which covered substantially all employees. Effective February 24, 2005, in conjunction with the change in ownership of our General Partner, our participation in this plan ended. Plan contributions on behalf of the Company of $0.9 million, $3.5 million and $3.2 million were recognized for the period January 1, 2005 through February 23, 2005, and during the years ended December 31, 2004 and 2003, respectively.

NOTE 16. COMMITMENTS AND CONTINGENCIES

Litigation

In the fall of 1999 and on December 1, 2000, the General Partner and the Partnership were named as defendants in two separate lawsuits in Jackson County Circuit Court, Jackson County, Indiana, styled *Ryan E. McCleery and Marcia S. McCleery, et al. v. Texas Eastern Corporation, et al.* (including the General Partner and Partnership) and *Gilbert Richards and Jean Richards v. Texas Eastern Corporation, et al.* (including the General Partner and Partnership). In both cases, the plaintiffs contend, among other things, that we and other defendants stored and disposed of toxic and hazardous substances and hazardous wastes in a manner that caused the materials to be released into the air, soil and water. They further contend that the release caused damages to the plaintiffs. In their complaints, the plaintiffs allege strict liability for both personal injury and property damage together with gross negligence, continuing nuisance, trespass, criminal mischief and loss of consortium. The plaintiffs are seeking compensatory, punitive and treble damages. On January 27, 2005, we entered into Release and Settlement Agreements with the McCleery plaintiffs and the Richards plaintiffs dismissing all of these plaintiffs' claims on terms that did not have a material adverse effect on our financial position, results of operations or cash flows. Although we did not settle with all plaintiffs and we therefore remain named parties in the *Ryan E. McCleery and Marcia S. McCleery, et al. v. Texas Eastern Corporation, et al*. action, a co-defendant has agreed to indemnify us for all remaining claims asserted against us. Consequently, we do not believe that the outcome of these remaining claims will have a material adverse effect on our financial position, results of operations or cash flows.

On December 21, 2001, TE Products was named as a defendant in a lawsuit in the 10th Judicial District, Natchitoches Parish, Louisiana, styled *Rebecca L. Grisham et al. v. TE Products Pipeline Company, Limited Partnership*. In this case, the plaintiffs contend that our pipeline, which crosses the plaintiffs' property, leaked toxic products onto their property and, consequently caused damages to them. We have filed an answer to the plaintiffs' petition denying the allegations, and we are defending ourselves vigorously against the lawsuit. The plaintiffs have not stipulated the amount of damages they are seeking in the suit; however, this case is covered by insurance. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

On April 2, 2003, Centennial was served with a petition in a matter styled *Adams, et al. v. Centennial Pipeline Company LLC, et al*. This matter involves approximately 2,000 plaintiffs who allege that over 200 defendants, including Centennial, generated, transported, and/or disposed of hazardous and toxic waste at two sites in Bayou Sorrell, Louisiana, an underground injection well and a landfill. The plaintiffs allege personal injuries, allergies, birth defects, cancer and death. The underground injection well has been in operation since May 1976. Based upon current information, Centennial appears to be a *de minimis* contributor, having used the disposal site during the two month time period of December 2001 to January 2002. Marathon has been handling this matter for Centennial under its operating agreement with Centennial. TE Products has a 50% ownership interest in Centennial. On November 30, 2004, the court approved a class settlement. The time period for parties to appeal this settlement expired in March 2005, and the class settlement became final. The terms of the settlement did not have a material adverse effect on our financial position, results of operations or cash flows.

In May 2003, the General Partner was named as a defendant in a lawsuit styled *John R. James, et al. v. J Graves Insulation Company, et al.* as filed in the first Judicial District Court, Caddo Parish, Louisiana. There are numerous plaintiffs identified in the action that are alleged to have suffered damages as a result of alleged exposure to asbestos-containing products and materials. According to the petition and as a result of a preliminary investigation, the General Partner believes that the only claim asserted against it results from one individual for the period from July 1971 through June 1972, who is alleged to have worked on a facility owned by the General Partner's predecessor. This period represents a small portion of the total alleged exposure period from January 1964 through December 2001 for this individual. The individual's claims involve numerous employers and alleged job sites. The General Partner has been unable to confirm involvement by the General Partner or its predecessors with the alleged location, and it is uncertain at this time whether this case is covered by insurance. Discovery is planned, and the General Partner intends to defend itself vigorously against this lawsuit. The plaintiffs have not stipulated the amount of damages that they are seeking in this suit. We are obligated to reimburse the General Partner for any costs it incurs related to this lawsuit. We cannot estimate the loss, if any, associated with this pending lawsuit. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

On August 5, 2005, we were named as a third-party defendant in a matter styled *ConocoPhillips, et al. v. BP Amoco Seaway Products Pipeline Company* as filed in the 55th Judicial District of Harris County, Texas. ConocoPhillips alleges a right to indemnity from BP Amoco Seaway Products Pipeline Company ("BP Amoco") for tax liability incurred by ConocoPhillips as a result of the reverse merger of Seaway Pipeline Company (the "Original Seaway Partnership"). The reverse merger of the Original Seaway Partnership was undertaken in preparation for our purchase of ARCO Pipe Line Company pursuant to the Amended and Restated Purchase Agreement (the "Purchase Agreement") dated May 10, 2000, between us and Atlantic Richfield Company. BP Amoco has claimed a right to indemnity from us under the Purchase Agreement should BP Amoco have any indemnity liability to ConocoPhillips. ConocoPhillips alleges the income tax liability to be approximately $4.0 million. On January 20, 2006, we entered into a settlement agreement with BP Amoco dismissing and resolving all of BP Amoco's claims. The terms of the settlement did not have a material adverse effect on our financial position, results of operations or cash flows.

In 1991, we were named as a defendant in a matter styled *Jimmy R. Green, et al. v. Cities Service Refinery, et al.* as filed in the 26th Judicial District Court of Bossier Parish, Louisiana. The plaintiffs in this matter reside or formerly resided on land that was once the site of a refinery owned by one of our co-defendants. The former refinery is located near our Bossier City facility. Plaintiffs have claimed personal injuries and property damage arising from alleged contamination of the refinery property. The plaintiffs have recently pursued certification as a class and have significantly increased their demand to approximately $175.0 million. This revised demand includes amounts for environmental restoration not previously claimed by the plaintiffs. We have never owned any interest in the refinery property made the basis of this action, and we do not believe that we contributed to any alleged contamination of this property. While we cannot predict the ultimate outcome, we do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

In addition to the litigation discussed above, we have been, in the ordinary course of business, a defendant in various lawsuits and a party to various other legal proceedings, some of which are covered in whole or in part by insurance. We believe that the outcome of these lawsuits and other proceedings will not individually or in the aggregate have a future material adverse effect on our consolidated financial position, results of operations or cash flows.

Regulatory Matters

Our operations are subject to federal, state and local laws and regulations governing the discharge of materials into the environment and various safety matters. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of injunctions delaying or prohibiting certain activities and the need to perform investigatory and remedial activities. We believe our operations have been and are in material compliance with applicable environmental and safety laws and regulations, and that compliance with existing environmental laws and regulations are not expected to have a material adverse effect on our competitive position, financial positions, results of operations or cash flows. However, risks of significant costs and liabilities are inherent in pipeline operations, and we cannot assure that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly strict environmental and safety laws and regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us. At December 31, 2005 and 2004, we have an accrued liability of $2.4 million and $5.0 million, respectively, related to sites requiring environmental remediation activities.

On March 26, 2004, a decision in *ARCO Products Co., et al. v. SFPP*, Docket OR96-2-000, was issued by the FERC, which made several significant determinations with respect to finding "changed circumstances" under the Energy Policy Act of 1992 ("EP Act"). The decision largely clarifies, but does not fully quantify, the standard required for a complainant to demonstrate that an oil pipeline's rates are no longer subject to the rate protection of the EP Act by demonstrating that a substantial change in circumstances has occurred since 1992 with respect to the basis of the rates being challenged. In the decision, the FERC found that a limited number of rate elements will significantly affect the economic basis for a pipeline company's rates. The elements identified in the decision are volume changes, allowed total return and total cost-of-service (including major cost elements such as rate base, tax rates and tax allowances, among others). The FERC did reject, however, the use of changes in tax rates and income tax allowances as stand-alone factors. Judicial review of that decision, which has been sought by a number of parties to the case, is currently pending before the U.S. Court of Appeals for the District of Columbia Circuit. We have not yet determined the impact, if any, that the decision, if it is ultimately upheld, would have on our rates if they were reviewed under the criteria of this decision.

On July 20, 2004, the District of Columbia Circuit issued an opinion in *BP West Coast Products LLC v. FERC*. In reviewing a series of orders involving SFPP, L.P., the court held among other things that the FERC had not adequately justified its policy of providing an oil pipeline limited partnership with an income tax allowance equal to the proportion of its income attributable to partnership interests owned by corporate partners. Under the FERC's initial ruling, SFPP, L.P. was permitted an income tax allowance on its cost-of-service filing for the percentage of its net operating (pre-tax) income attributable to partnership units held by corporations, and was denied an income tax allowance equal to the percentage attributable to partnership units held by non-corporate partners. The court remanded the case back to the FERC for further review. As a result of the court's remand, on May 4, 2005, the FERC issued its Policy Statement on Income Tax Allowances, which permits regulated partnerships, limited liability companies and other pass-through entities an income tax allowance on their income attributable to any owner that has an actual or potential income tax liability on that income, regardless whether the owner is an individual or corporation. If there is more than one level of pass-through entities, the regulated company income must be traced to where the ultimate tax liability lies. The Policy Statement is to be applied in individual cases, and the regulated entity bears the burden of proof to establish the tax status of its owners. On December 16, 2005, the FERC issued the first of those decisions, in an order involving SFPP (the "SFPP Order").

The SFPP Order confirmed that an MLP is entitled to a tax allowance with respect to partnership income for which there is an "actual or potential income tax liability" and determined that a unitholder that is required to file a Form 1040 or Form 1120 tax return that includes partnership income or loss is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income. The FERC also established certain other presumptions, including that corporate unitholders are presumed to be taxed at the maximum corporate tax rate of 35% while individual unitholders (and certain other types of unitholders taxed like individuals) are presumed to be taxed at a 28% tax rate. The SFPP Order remains subject to further administrative proceedings (including compliance filings by SFPP and possible rehearing requests), as well as potential judicial review. The ultimate outcome of the FERC's inquiry on income tax allowance should not affect our current rates and rate structure because our rates are not based on cost-of-service methodology. However, the outcome of the income tax allowance would become relevant to us should we (i) elect in the future to use cost-of-service to support our rates, or (ii) be required to use such methodology to defend our indexed rates.

In 1994, the Louisiana Department of Environmental Quality ("LDEQ") issued a compliance order for environmental contamination at our Arcadia, Louisiana, facility. In 1999, our Arcadia facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this contamination. Effective March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility. This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility. At December 31, 2005, we have an accrued liability of $0.2 million for remediation costs at our Arcadia facility. We do not expect that the completion of the remediation program proposed to the LDEQ will have a future material adverse effect on our financial position, results of operations or cash flows.

On March 17, 2003, we experienced a release of 511 barrels of jet fuel from a storage tank at our Blue Island terminal located in Cook County, Illinois. As a result of the release, we have entered into an Agreed Order with the State of Illinois, which required us to conduct an environmental investigation. At this time, we have complied with the terms of the Agreed Order, and the results of the environmental investigation indicated there were no soil or groundwater impacts from the release. On August 30, 2005, a final settlement was reached with the State of Illinois. The settlement included the payment of a civil penalty of $0.1 million and the requirement that we make certain modifications to the equipment of the facility, none of which are expected to have a material adverse effect on our financial position, results of operations or cash flows.

On July 22, 2004, we experienced a release of approximately 12 barrels of jet fuel from a sump at our Lebanon, Ohio, terminal. The released jet fuel was contained within a storm water retention pond located on the terminal property. Six migratory waterfowl were affected by the jet fuel and were subsequently euthanized by or at the request of the United States Fish and Wildlife Service ("USFWS"). On October 1, 2004, the USFWS served us with a Notice of Violation, alleging that we violated 16 USC 703 of the Migratory Bird Treaty Act for the "take[ing] of migratory birds by illegal methods." On February 7, 2005, we entered into a Memorandum of Understanding with the USFWS, settling all aspects of this matter. The terms of this settlement did not have a material effect on our financial position, results of operations or cash flows.

On July 27, 2004, we received notice from the United States Department of Justice ("DOJ") of its intent to seek a civil penalty against us related to our November 21, 2001, release of approximately 2,575 barrels of jet fuel from our 14-inch diameter pipeline located in Orange County, Texas. The DOJ, at the request of the Environmental Protection Agency, is seeking a civil penalty against us for alleged violations of the Clean Water Act ("CWA") arising out of this release. We are in discussions with the DOJ regarding this matter and have responded to its request for additional information. The maximum statutory penalty proposed by the DOJ for this alleged violation of the CWA is $2.1 million. We do not expect any civil penalty to have a material adverse effect on our financial position, results of operations or cash flows.

On September 18, 2005, a propane release and fire occurred at our Todhunter facility, near Middletown, Ohio. The incident resulted in the death of one of our employees. There were no other injuries. On or about February 22, 2006, we received verbal notification from a representative of the Occupational Safety and Health Administration that they intend to serve us with a citation arising out of this incident. At this time, we have not received any citation, and we cannot predict with certainty the amount of any fine or penalty associated with any such citation; however, we do not expect any fine or penalty to have a material adverse effect on our financial position, results of operations or cash flows.

Rates of interstate petroleum products and crude oil pipeline companies, like us, are currently regulated by the FERC primarily through an index methodology, which allows a pipeline to change its rates based on the change from year to year in the Producer Price Index for finished goods ("PPI Index"). Effective as of February 24, 2003, FERC Order on Remand modified the PPI Index from PPI — 1% to PPI. On April 22, 2003, several shippers filed a petition in the United States Court of Appeals for the District of Columbia Circuit (the "Court"), *Flying J. Inc,. Lion Oil Company, Sinclair Oil Corporation and Tesoro Refining and Marketing Company vs. Federal Energy Regulatory Commission*; Docket No. 03-1107, seeking a review of whether the FERC's adoption of the PPIIndex was reasonable and supported by the evidence. On April 9, 2004, the Court handed down a decision denying the shippers' petition for review, stating the shippers failed to establish that any of the FERC's methodological choices (or combination of choices) were both erroneous and harmful.

As an alternative to using the PPI Index, interstate petroleum products and crude oil pipeline companies may elect to support rate filings by using a cost-of-service methodology, competitive market showings ("Market-Based Rates") or agreements between shippers and petroleum products and crude oil pipeline companies that the rate is acceptable.

Other

Centennial entered into credit facilities totaling $150.0 million, and as of December 31, 2005, $150.0 million was outstanding under those credit facilities. TE Products and Marathon have each guaranteed one-half of the repayment of Centennial's outstanding debt balance (plus interest) under a long-term credit agreement, which expires in 2024, and a short-term credit agreement, which expires in 2007. The guarantees arose in order for Centennial to obtain adequate financing, and the proceeds of the credit agreements were used to fund construction and conversion costs of its pipeline system. Prior to the expiration of the long-term credit agreement, TE Products could be relinquished from responsibility under the guarantee should Centennial meet certain financial tests. If Centennial defaults on its outstanding balance, the estimated maximum potential amount of future payments for TE Products and Marathon is $75.0 million each at December 31, 2005.

TE Products, Marathon and Centennial have entered into a limited cash call agreement, which allows each member to contribute cash in lieu of Centennial procuring separate insurance in the event of a third-party liability arising from a catastrophic event. There is an indefinite term for the agreement and each member is to contribute cash in proportion to its ownership interest, up to a maximum of $50.0 million each. As a result of the catastrophic event guarantee, TE Products has recorded a $4.6 million obligation, which represents the present value of the estimated amount that we would have to pay under the guarantee. If a catastrophic event were to occur and we were required to contribute cash to Centennial, contributions exceeding our deductible might be covered by our insurance.

One of our subsidiaries, TCO, has entered into master equipment lease agreements with finance companies for the use of various equipment. We have guaranteed the full and timely payment and performance of TCO's obligations under the agreements. Generally, events of default would trigger our performance under the guarantee. The maximum potential amount of future payments under the guarantee is not estimable, but would include base rental payments for both current and future equipment, stipulated loss payments in the event any equipment is stolen, damaged, or destroyed and any future indemnity payments. We carry insurance coverage that may offset any payments required under the guarantees.

On February 24, 2005, the General Partner was acquired from DEFS by DFI. The General Partner owns a 2% general partner interest in us and is the general partner of the Partnership. On March 11, 2005, the Bureau of Competition of the Federal Trade Commission ("FTC") delivered written notice to DFI's legal advisor that it was conducting a non-public investigation to determine whether DFI's acquisition of the General Partner may substantially lessen competition. The General Partner is cooperating fully with this investigation.

Substantially all of the petroleum products that we transport and store are owned by our customers. At December 31, 2005, TCTM and TE Products had approximately 4.0 million barrels and 22.5 million barrels, respectively, of products in their custody that was owned by customers. We are obligated for the transportation, storage and delivery of such products on behalf of our customers. We maintain insurance adequate to cover product losses through circumstances beyond our control.

We carry insurance coverage consistent with the exposures associated with the nature and scope of our operations. Our current insurance coverage includes (1) commercial general liability insurance for liabilities to third parties for bodily injury and property damage resulting from our operations; (2) workers' compensation coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage, and (4) property insurance covering the replacement value of all real and personal property damage, including damages arising from earthquake, flood damage and business interruption/extra expense. For select assets, we also carry pollution liability insurance that provides coverage for historical and gradual pollution events. All coverages are subject to certain deductibles, limits or sub-limits and policy terms and conditions.

We also maintain excess liability insurance coverage above the established primary limits for commercial general liability and automobile liability insurance. Limits, terms, conditions and deductibles are commensurate with the nature and scope of our operations. The cost of our general insurance coverages has increased over the past year reflecting the changing conditions of the insurance markets. These insurance policies, except for the pollution liability policies, are through EPCO (see Note 7).

NOTE 17. SEGMENT INFORMATION

We have three reporting segments:

- Our Downstream Segment, which is engaged in the transportation and storage of refined products, LPGs and petrochemicals;
- Our Upstream Segment, which is engaged in the gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals; and
- Our Midstream Segment, which is engaged in the gathering of natural gas, fractionation of NGLs and transportation of NGLs.

The amounts indicated below as "Partnership and Other" relate primarily to intersegment eliminations and assets that we hold that have not been allocated to any of our reporting segments.

Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. The two largest operating expense items of the Downstream Segment are labor and electric power. We generally realize higher revenues during the first and fourth quarters of each year since our operations are somewhat seasonal. Refined products volumes are generally higher during the second and third quarters because of greater demand for gasolines during the spring and summer driving seasons. LPGs volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating. Our Downstream Segment

also includes the results of operations of the northern portion of the Dean Pipeline, which transports, refinery grade propylene from Mont Belvieu to Point Comfort, Texas. Our Downstream Segment also includes our equity investments in Centennial and MB Storage (see Note 6).

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale of the crude oil to local refineries, marketers or other end users. Our Upstream Segment also includes our equity investment in Seaway. Seaway consists of large diameter pipelines that transport crude oil from Seaway's marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

Our Midstream Segment revenues are earned from the fractionation of NGLs in Colorado, transportation of NGLs from two trunkline NGL pipelines in South Texas, two NGL pipelines in East Texas and a pipeline system (Chaparral) from West Texas and New Mexico to Mont Belvieu; the gathering of natural gas in the Green River Basin in southwestern Wyoming, through Jonah, and the gathering of CBM and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde. On March 31, 2006, we sold our ownership interest in the Jonah Pioneer silica gel natural gas processing plant located near Opal, Wyoming to an affiliate of Enterprise for $38.0 million in cash (see Note 5 in the Notes to the Consolidated Financial Statements). Operating results of the Pioneer plant for the years ended December 31, 2005 and 2004 are shown as discontinued operations.

The tables below include financial information by reporting segment for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Year Ended December 31, 2005					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 8,062,131	$ —	$ 8,062,131	$ (323)	$ 8,061,808
Operating revenues	287,191	48,108	211,171	546,470	(3,244)	543,226
Purchases of petroleum products	—	7,989,682	—	7,989,682	(3,244)	7,986,438
Operating expenses, including power	159,784	70,340	58,701	288,825	(323)	288,502
Depreciation and amortization expense	39,403	17,161	54,165	110,729	—	110,729
Gains on sales of assets	(139)	(118)	(411)	(668)	—	(668)
Operating income	88,143	33,174	98,716	220,033	—	220,033
Equity earnings (losses)	(2,984)	23,078	—	20,094	—	20,094
Other income, net	755	156	224	1,135	—	1,135
Earnings before interest from continuing operations	85,914	56,408	98,940	241,262	—	241,262
Discontinued operations	—	—	3,150	3,150	—	3,150
Earnings before interest	$ 85,914	$ 56,408	$ 102,090	$ 244,412	$ —	$ 244,412

	Year Ended December 31, 2004					
	Downstream Segment (as restated)	Upstream Segment (as restated)	Midstream Segment	Segments Total (as restated)	Partnership and Other	Consolidated (as restated)
Sales of petroleum products	$ —	$ 5,426,832	$ —	$ 5,426,832	$ —	$ 5,426,832

Operating revenues	279,400	49,163	195,902	524,465	(3,207)	521,258
Purchases of petroleum products	—	5,370,234	—	5,370,234	(3,207)	5,367,027
Operating expenses, including power	165,528	60,893	58,967	285,388	—	285,388
Depreciation and amortization expense	43,135	13,130	56,019	112,284	—	112,284
Gains on sales of assets	(526)	(527)	—	(1,053)	—	(1,053)
Operating income	71,263	32,265	80,916	184,444	—	184,444
Equity earnings (losses)	(6,544)	28,692	—	22,148	—	22,148
Other income, net	787	406	127	1,320	—	1,320
Earnings before interest from continuing operations	65,506	61,363	81,043	207,912	—	207,912
Discontinued operations	—	—	2,689	2,689	—	2,689
Earnings before interest	$ 65,506	$ 61,363	$ 83,732	$ 210,601	$ —	$ 210,601

	Year Ended December 31, 2003					
	Downstream Segment (as restated)	Upstream Segment (as restated)	Midstream Segment	Segments Total (as restated)	Partnership and Other	Consolidated (as restated)
Sales of petroleum products	$ —	$ 3,766,651	$ —	$ 3,766,651	$ —	$ 3,766,651
Operating revenues	266,427	39,564	185,105	491,096	(1,915)	489,181
Purchases of petroleum products	—	3,713,122	—	3,713,122	(1,915)	3,711,207
Operating expenses, including power	151,103	57,314	47,020	255,437	—	255,437
Depreciation and amortization expense	31,620	11,311	57,797	100,728	—	100,728
Gain on sale of assets	—	(3,948)	—	(3,948)	—	(3,948)
Operating income	83,704	28,416	80,288	192,408	—	192,408
Equity earnings (losses)	(7,384)	20,258	—	12,874	—	12,874
Other income, net	226	306	289	821	(73)	748
Earnings before interest	$ 76,546	$ 48,980	$ 80,577	$ 206,103	$ (73)	$ 206,030

The following table provides the total assets, capital expenditures and significant non-cash investing activities for each segment as of and for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
December 31, 2005:						
Total assets	$ 1,056,217	$ 1,353,492	$ 1,280,548	$ 3,690,257	$ (9,719)	$ 3,680,538
Capital expenditures	58,609	40,954	119,837	219,400	1,153	220,553
Non-cash investing activities	1,429	—	—	1,429	—	1,429
December 31, 2004 (as restated):						
Total assets	$ 959,042	$ 1,069,007	$ 1,184,184	$ 3,212,233	$ (25,949)	$ 3,186,284
Capital expenditures	80,930	37,448	37,677	156,055	694	156,749
Capital expenditures for discontinued operations	—	—	7,398	7,398	—	7,398
December 31, 2003 (as restated):						
Total assets	$ 911,184	$ 833,723	$ 1,194,844	$ 2,939,751	$ (5,271)	$ 2,934,480
Capital expenditures	59,061	13,427	54,072	126,560	147	126,707
Capital expenditures for discontinued operations	—	—	13,810	13,810	—	13,810
Non-cash investing activities	61,042	—	—	61,042	—	61,042

The following table reconciles the segments total earnings before interest to consolidated net income for the three years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,		
	2005	2004 (as restated)	2003 (as restated)
Earnings before interest	$ 244,412	$ 210,601	$ 206,030
Interest expense — net	(81,861)	(72,053)	(84,250)
Net income	$ 162,551	$ 138,548	$ 121,780

NOTE 18. COMPREHENSIVE INCOME

SFAS No. 130, *Reporting Comprehensive Income* requires certain items such as foreign currency translation adjustments, minimum pension liability adjustments and unrealized gains and losses on certain investments to be reported in a financial statement. As of and for the year ended December 31, 2005, the components of comprehensive income were due to crude oil hedges. The crude oil hedges mature in December 2006. While the crude oil hedges are in effect, changes in the fair values of the crude oil hedges, to the extent the hedges are effective, are recognized in other comprehensive income until they are recognized in net income in future periods. As of and for the year ended December 31, 2004, the components of comprehensive income were due to the interest rate swap related to our variable rate revolving credit facility, which was designated as a cash flow hedge. The interest rate swap matured in

April 2004. While the interest rate swap was in effect, changes in the fair value of the cash flow hedge, to the extent the hedge was effective, were recognized in other comprehensive income until the hedge interest costs were recognized in net income.

The accumulated balance of other comprehensive income related to our cash flow hedges is as follows (in thousands):

Balance at December 31, 2002 (as restated)	$ (20,055)
Reclassification due to discontinued portion of cash flow hedge	989
Transferred to earnings	14,417
Change in fair value of cash flow hedge	1,747
Balance at December 31, 2003 (as restated)	$ (2,902)
Transferred to earnings	2,939
Change in fair value of cash flow hedge	(37)
Balance at December 31, 2004 (as restated)	$ —
Changes in fair values of crude oil cash flow hedges	11
Balance at December 31, 2005	$ 11

NOTE 19. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Our significant operating subsidiaries, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P., have issued unconditional guarantees of our debt securities. The guarantees are full, unconditional, and joint and several. TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. are collectively referred to as the "Guarantor Subsidiaries."

The following supplemental condensed consolidating financial information reflects our separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of our other non-guarantor subsidiaries, the combined consolidating adjustments and eliminations and our consolidated accounts for the dates and periods indicated. For purposes of the following consolidating information, our investments in our subsidiaries and the Guarantor Subsidiaries' investments in their subsidiaries are accounted for under the equity method of accounting.

	December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 40,977	$ 107,692	$ 789,486	$ (39,026)	$ 899,129
Property, plant and equipment — net	—	1,335,724	624,344	—	1,960,068
Equity investments	1,201,388	461,741	202,343	(1,505,816)	359,656
Intercompany notes receivable	1,134,093	—	—	(1,134,093)	—
Intangible assets	—	345,005	31,903	—	376,908
Other assets	5,532	22,170	57,075	—	84,777
Total assets	$ 2,381,990	$ 2,272,332	$ 1,705,151	$ (2,678,935)	$ 3,680,538
Liabilities and partners' capital					
Current liabilities	$ 43,236	$ 140,743	$ 793,683	$ (40,451)	$ 937,211
Long-term debt	1,135,973	389,048	—	—	1,525,021
Intercompany notes payable	—	635,263	498,832	(1,134,095)	—
Other long term liabilities	1,422	14,564	950	—	16,936
Total partners' capital	1,201,359	1,092,714	411,686	(1,504,389)	1,201,370
Total liabilities and partners' capital	$ 2,381,990	$ 2,272,332	$ 1,705,151	$ (2,678,935)	$ 3,680,538

	December 31, 2004 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 44,125	$ 85,992	$ 576,365	$ (62,928)	$ 643,554
Property, plant and equipment — net	—	1,211,312	492,390	—	1,703,702
Equity investments	1,011,131	420,343	202,326	(1,270,493)	363,307
Intercompany notes receivable	1,084,034	—	—	(1,084,034)	—
Intangible assets	—	372,621	34,737	—	407,358
Other assets	5,980	22,183	40,200	—	68,363
Total assets	$ 2,145,270	$ 2,112,451	$ 1,346,018	$ (2,417,455)	$ 3,186,284
Liabilities and partners' capital					
Current liabilities	$ 45,255	$ 142,513	$ 556,474	$ (62,930)	$ 681,312
Long-term debt	1,086,909	393,317	—	—	1,480,226
Intercompany notes payable	—	676,993	407,040	(1,084,033)	—

Other long term liabilities	2,003	9,980	1,660	—	13,643
Total partners' capital	1,011,103	889,648	380,844	(1,270,492)	1,011,103
Total liabilities and partners' capital	$ 2,145,270	$ 2,112,451	$ 1,346,018	$ (2,417,455)	$ 3,186,284

	Year Ended December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 439,944	$ 8,168,657	$ (3,567)	$ 8,605,034
Costs and expenses	—	285,072	8,104,164	(3,567)	8,385,669
Gains on sales of assets	—	(551)	(117)	—	(668)
Operating income	—	155,423	64,610	—	220,033
Interest expense — net	—	(54,011)	(27,850)	—	(81,861)
Equity earnings	162,551	57,088	23,078	(222,623)	20,094
Other income — net	—	901	234	—	1,135
Income from continuing operations	162,551	159,401	60,072	(222,623)	159,401
Discontinued operations	—	3,150	—	—	3,150
Net income	$ 162,551	$ 162,551	$ 60,072	$ (222,623)	$ 162,551

	Year Ended December 31, 2004 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 420,060	$ 5,531,237	$ (3,207)	$ 5,948,090
Costs and expenses	—	294,155	5,473,751	(3,207)	5,764,699
Gains on sales of assets	—	(526)	(527)	—	(1,053)
Operating income	—	126,431	58,013	—	184,444
Interest expense — net	—	(48,902)	(23,151)	—	(72,053)
Equity earnings	138,548	57,454	28,692	(202,546)	22,148
Other income — net	—	876	444	—	1,320
Income from continuing operations	138,548	135,859	63,998	(202,546)	135,859
Discontinued operations	—	2,689	—	—	2,689
Net income	$ 138,548	$ 138,548	$ 63,998	$ (202,546)	$ 138,548

	Year Ended December 31, 2003 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 399,504	$ 3,858,243	$ (1,915)	$ 4,255,832
Costs and expenses	—	262,971	3,806,316	(1,915)	4,067,372
Gain on sale of assets	—	—	(3,948)	—	(3,948)
Operating income	—	136,533	55,875	—	192,408
Interest expense — net	—	(52,903)	(31,420)	73	(84,250)
Equity earnings	121,780	37,689	20,258	(166,853)	12,874
Other income — net	—	461	360	(73)	748
Net income	$ 121,780	$ 121,780	$ 45,073	$ (166,853)	$ 121,780

	Year Ended December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Cash flows from continuing operating activities					
Net income	$ 162,551	$ 162,551	$ 60,072	$ (222,623)	$ 162,551
Adjustments to reconcile net income to net cash provided by continuing operating activities:					
Income from discontinued operations	—	(3,150)	—	—	(3,150)
Depreciation and amortization	—	82,536	28,193	—	110,729
Earnings in equity investments, net of distributions	88,550	14,598	1,576	(87,733)	16,991
Gains on sales of assets	—	(551)	(117)	—	(668)
Changes in assets and liabilities and other	(54,540)	(57,645)	22,884	53,571	(35,730)
Net cash provided by continuing operating activities	196,561	198,339	112,608	(256,785)	250,723
Cash flows from discontinued operations	—	3,782	—	—	3,782

Net cash provided by operating activities	196,561	202,121	112,608	(256,785)	254,505
Cash flows from investing activities	(278,806)	(31,529)	(180,486)	139,906	(350,915)
Cash flows from financing activities	80,107	(184,126)	65,097	119,029	80,107
Net increase in cash and cash equivalents	(2,138)	(13,534)	(2,781)	2,150	(16,303)
Cash and cash equivalents at beginning of period	4,116	13,596	2,826	(4,116)	16,422
Cash and cash equivalents at end of period	$ 1,978	$ 62	$ 45	$ (1,966)	$ 119

	Year Ended December 31, 2004 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Cash flows from continuing operating activities					
Net income	$ 138,548	$ 138,548	$ 63,998	$ (202,546)	$ 138,548
Adjustments to reconcile net income to net cash provided by continuing operating activities:					
Income from discontinued operations	—	(2,689)	—	—	(2,689)
Depreciation and amortization	—	89,438	22,846	—	112,284
Earnings in equity investments, net of distributions	94,509	(130)	8,208	(77,522)	25,065
Gains on sales of assets	—	(526)	(527)	—	(1,053)
Changes in assets and liabilities and other	(158,726)	29,707	(30,930)	151,690	(8,259)
Net cash provided by continuing operating activities	74,331	254,348	63,595	(128,378)	263,896
Cash flows from discontinued operations	—	3,271	—	—	3,271
Net cash provided by operating activities	74,331	257,619	63,595	(128,378)	267,167
Cash flows from continuing investing activities	98	(26,662)	(40,864)	(115,331)	(182,759)
Cash flows from discontinued investing activities	—	(7,398)	—	—	(7,398)
Cash flows from investing activities	98	(34,060)	(40,864)	(115,331)	(190,157)
Cash flows from financing activities	(90,057)	(229,206)	(25,575)	254,781	(90,057)
Net decrease in cash and cash equivalents	(15,628)	(5,647)	(2,844)	11,072	(13,047)
Cash and cash equivalents at beginning of period	19,744	19,243	5,670	(15,188)	29,469
Cash and cash equivalents at end of period	$ 4,116	$ 13,596	$ 2,826	$ (4,116)	$ 16,422

	Year Ended December 31, 2003 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Cash flows from operating activities					
Net income	$ 121,780	$ 121,780	$ 45,073	$ (166,853)	$ 121,780
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	80,114	20,614	—	100,728
Earnings in equity investments, net of distributions	80,718	7,548	2,482	(75,619)	15,129
Gain on sale of assets	—	—	(3,948)	—	(3,948)
Changes in assets and liabilities and other	48,432	5,576	1,075	(46,348)	8,735
Net cash provided by operating activities	250,930	215,018	65,296	(288,820)	242,424
Cash flows from continuing investing activities	(175,568)	(164,872)	(37,589)	203,531	(174,498)
Cash flows from investing activities	—	(13,810)	—	—	(13,810)
Cash flows from discontinued investing activities	(175,568)	(178,682)	(37,589)	203,531	(188,308)
Cash flows from financing activities	(55,618)	(25,340)	(44,758)	70,101	(55,615)
Net increase (decrease) in cash and cash equivalents	19,744	10,996	(17,051)	(15,188)	(1,499)
Cash and cash equivalents at beginning of period	—	8,247	22,721	—	30,968
Cash and cash equivalents at end of period	$ 19,744	$ 19,243	$ 5,670	$ (15,188)	$ 29,469

NOTE 20. RESTATEMENT OF CONSOLIDATED FINANCIAL STATEMENTS

We are restating our previously reported consolidated financial statements for the fiscal years ended December 31, 2003 and 2004. For the impact of the restated consolidated financial results for the quarterly periods during the years ended December 31, 2005 and 2004, see Note 21. We have determined that our method of accounting for the $33.4 million excess investment in Centennial, previously described as an intangible asset with an indefinite life, and the $27.1 million excess investment in Seaway, previously described as equity method goodwill, was incorrect. Through our accounting for these excess investments in Centennial and Seaway as intangible assets with indefinite lives and equity method goodwill, respectively, we have been testing the amounts for impairment on an annual basis as opposed to amortizing them over a determinable life. We determined that it would be more appropriate to account for these excess investments as intangible assets with determinable lives. As a result, we made non-cash adjustments that reduced the net value of the excess investments in Centennial and Seaway, and increased amortization expense allocated to our equity earnings. The effect of this restatement caused a $3.8 million and $4.0 million reduction to net income as previously reported for the fiscal years ended December 31, 2004 and 2003, respectively. As a result of the accounting correction, net income for the fiscal year ended December 31, 2005, includes a charge of $4.8 million, of which $3.8 million relates to the first nine months. Additionally, partners' capital at December 31, 2002, reflects a $2.5 million reduction representing the cumulative effect of this correction for fiscal years ended December 31, 2000 through 2002.

While we believe the impacts of these non-cash adjustments are not material to any previously issued financial statements, we determined that the cumulative adjustment for these non-cash items was too material to record in the fourth quarter of 2005, and therefore it was most appropriate to restate prior periods' results. These non-cash adjustments had no effect on our operating income, compensation expense, debt balances or ability to meet all requirements related to our debt facilities. The restatement had no impact on total cash flows from operating

activities, investing activities or financing activities. All amounts in the accompanying consolidated financial statements have been adjusted for this restatement.

We will continue to amortize the $30.0 million excess investment in Centennial related to a contract using units-of-production methodology over a 10-year life. The remaining $3.4 million related to a pipeline will continue to be amortized on a straight-line basis over 35 years. We will continue to amortize the $27.1 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to a pipeline.

The following tables summarize the impact of the restatement adjustment on previously reported balance sheet amounts for the year ended December 31, 2004, and income statement amounts and cash flow amounts for the years ended December 31, 2004 and 2003 (in thousands):

Balance Sheet Amounts;

	December 31, 2004		
	As Previously Reported	Adjustment	As Restated
Equity investments	$ 373,652	$ (10,345)	$ 363,307
Total assets	$ 3,196,629	$ (10,345)	$ 3,186,284
Capital:			
General partner's interest	$ (33,006)	$ (2,875)	$ (35,881)
Limited partners' interest	1,054,454	(7,470)	1,046,984
Total partners' capital	1,021,448	(10,345)	1,011,103
Total liabilities and partners' capital	$ 3,196,629	$ (10,345)	$ 3,186,284

Income Statement Amounts:

	Years Ended December 31,	
	2004	2003
Equity earnings as previously reported	$ 25,981	$ 16,863
Adjustment for amortization of excess investments	(3,833)	(3,989)
Equity earnings as restated	$ 22,148	$ 12,874
Net income as previously reported	$ 142,381	$ 125,769
Adjustment for amortization of excess investments	(3,833)	(3,989)
Net income as restated	$ 138,548	$ 121,780
Net Income Allocation as previously reported:		
Limited Partner Unitholders	$ 101,307	$ 89,191
Class B Unitholder	—	1,806
General Partner	41,074	34,772
Total net income allocated	$ 142,381	$ 125,769
Basic and diluted net income per Limited Partner and Class B Unit as previously reported	$ 1.61	$ 1.52
Net Income Allocation as restated:		
Limited Partner Unitholders	$ 98,580	$ 86,357

Class B Unitholder	—	1,754
General Partner	39,968	33,669
Total net income allocated as restated	$ 138,548	$ 121,780
Basic and diluted net income per Limited Partner and Class B Unit as restated	$ 1.56	$ 1.47

Cash Flow Amounts;

	Year Ended December 31, 2004		
	As Previously Reported	Adjustment	As Restated
Cash flows from operating activities:			
Net income	$ 142,381	$ (3,833)	$ 138,548
Earnings in equity investments, net of distributions	21,232	3,833	25,065

	Year Ended December 31, 2003		
	As Previously Reported	Adjustment	As Restated
Cash flows from operating activities:			
Net income	$ 125,769	$ (3,989)	$ 121,780
Earnings in equity investments, net of distributions	11,140	3,989	15,129

Partners' Capital Amounts:

	Outstanding Limited Partner Units	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive Loss	Total
2002:					
Partners' capital at December 31, 2002 as previously reported	53,809,597	$ 12,770	$ 899,127	$ (20,055)	$ 891,842
Restatement adjustment	—	(666)	(1,727)	—	(2,393)
Partners' capital at December 31, 2002 as restated (unaudited)	53,809,597	$ 12,104	$ 897,400	$ (20,055)	$ 889,449
2003:					
Partners' capital at December 31, 2003 as previously reported	62,998,554	$ (7,181)	$ 1,119,404	$ (2,902)	$ 1,109,321
Restatement adjustment	—	(1,769)	(4,743)	—	(6,512)
Partners' capital at December 31, 2003 as restated	62,998,554	$ (8,950)	$ 1,114,661	$ (2,902)	$ 1,102,809
2004:					
Partners' capital at December 31, 2004 as previously reported	62,998,554	$ (33,006)	$ 1,054,454	$ —	$ 1,021,448
Restatement adjustment	—	(2,875)	(7,470)	—	(10,345)
Partners' capital at December 31, 2004 as restated	62,998,554	$ (35,881)	$ 1,046,984	$ —	$ 1,011,103

NOTE 21. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	First Quarter (as restated)	Second Quarter (as restated)	Third Quarter (as restated)	Fourth Quarter (as restated)
	(in thousands, except per Unit amounts)			
2005: (1)				
Operating revenues	$ 1,523,791	$ 2,087,385	$ 2,500,127	$ 2,493,731
Operating income	61,232	53,817	43,378	61,606
Income from continuing operations:				
As previously reported	$ 47,457	$ 41,387	$ 30,231	$ 44,137
Restatement adjustment	(1,152)	(1,311)	(1,348)	—
As restated	$ 46,305	$ 40,076	$ 28,883	$ 44,137
Income from discontinued operations	$ 1,124	$ 846	$ 692	$ 488

Net income:				
As previously reported	$ 48,581	$ 42,233	$ 30,923	$ 44,625
Restatement adjustment	(1,152)	(1,311)	(1,348)	—
As restated	$ 47,429	$ 40,922	$ 29,575	$ 44,625
Basic and diluted net income per Limited Partner Unit from continuing operations: (2) (3)				
As previously reported	$ 0.54	$ 0.44	$ 0.30	$ 0.45
Restatement adjustment	(0.01)	(0.02)	(0.01)	—
As restated	$ 0.53	$ 0.42	$ 0.29	$ 0.45
Basic and diluted net income per Limited Partner Unit from discontinued operations (3)	$ 0.01	$ 0.01	$ 0.01	$ —
Basic and diluted net income per Limited Partner Unit: (2)(3)				
As previously reported	$ 0.55	$ 0.45	$ 0.31	$ 0.45
Restatement adjustment	(0.01)	(0.02)	(0.01)	—
As restated	$ 0.54	$ 0.43	$ 0.30	$ 0.45

	First Quarter (as restated)	Second Quarter (as restated)	Third Quarter (as restated)	Fourth Quarter (as restated)
		(in thousands, except per Unit amounts)		
2004: (1)				
Operating revenues	$ 1,315,942	$ 1,352,107	$ 1,487,556	$ 1,792,485
Operating income	53,457	41,990	36,361	52,636
Income from continuing operations:				
As previously reported	$ 39,989	$ 37,348	$ 25,135	$ 37,220
Restatement adjustment	(713)	(1,129)	(1,085)	(906)
As restated	$ 39,276	$ 36,219	$ 24,050	$ 36,314
Income from discontinued operations	$ 444	$ 411	$ 720	$ 1,114
Net income:				
As previously reported	$ 40,433	$ 37,759	$ 25,855	$ 38,334
Restatement adjustment	(713)	(1,129)	(1,085)	(906)
As restated	$ 39,720	$ 36,630	$ 24,770	$ 37,428
Basic and diluted net income per Limited Partner Unit from continuing operations:				
As previously reported	$ 0.45	$ 0.43	$ 0.28	$ 0.42
Restatement adjustment	(0.01)	(0.02)	(0.01)	(0.01)
As restated	$ 0.44	$ 0.41	$ 0.27	$ 0.41
Basic and diluted net income per Limited Partner Unit from discontinued operations	$ 0.01	$ —	$ 0.01	$ 0.01
Basic and diluted net income per Limited Partner Unit:				
As previously reported	$ 0.46	$ 0.43	$ 0.29	$ 0.43
Restatement adjustment	(0.01)	(0.02)	(0.01)	(0.01)
As restated	$ 0.45	$ 0.41	$ 0.28	$ 0.42

(1) The quarterly financial information for 2004 and the first three quarters of 2005 reflect the impact of the restatement.

(2) The sum of the four quarters does not equal the total year due to rounding.

(3) Per Unit calculation includes 6,965,000 Units issued in May and June 2005.

NOTE 22. SUBSEQUENT EVENTS

In January 2006, we entered into interest rate swaps with a total notional amount of $200.0 million, whereby we will receive a floating rate of interest and will pay a fixed rate of interest for a two-year term. These interest rate swaps were executed to decrease the exposure to potential increases in floating interest rates. Using the balances of outstanding debt at December 31, 2005, these interest rate swaps decrease the level of floating interest rate debt from 41% to 29% of total outstanding debt.

On February 13, 2006, we and an affiliate of Enterprise entered into a letter agreement related to an additional expansion (the "Jonah Expansion") of the Jonah system (the "Letter Agreement"). The Jonah Expansion

will consist of the installation of approximately 90,000 horsepower of gas turbine compression at a new compression station, related new piping and certain related facilities, which is expected to increase capacity of the Jonah system from 1.5 billion cubic feet per day to 2.0 billion cubic feet per day. We expect to enter into a joint venture ("Joint Venture") agreement with Enterprise relating to the construction and financing of the Jonah Expansion. Enterprise will be responsible for all activities relating to the construction of the Jonah Expansion and will advance all amounts necessary to plan, engineer, construct or complete the Jonah Expansion (anticipated to be approximately $200.0 million). Such advance will constitute a subscription for an equity interest in the proposed Joint Venture (the "Subscription"). We expect the Jonah Expansion to be put into service in late 2006. We have the option to return to Enterprise up to 100% of the amount of the Subscription. If we return a portion of the Subscription to Enterprise, our relative interests in the proposed Joint Venture will be adjusted accordingly. The proposed Joint Venture will terminate without liability to either party if we return 100% of the Subscription.