DUKE ENERGY CORP
Form 10-K/A
April 03, 2006

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K/A

Amendment No. 2

FOR ANNUAL AND TRANSITION REPORTS

PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2005

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ______ to ______

Commission file number 1-4928

DUKE ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

North Carolina	**56-0205520**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**
526 South Church Street, Charlotte, North Carolina	**28202-1803**
(Address of principal executive offices)	**(Zip Code)**

704-594-6200

(Registrant s telephone number, including area code)

SECURITIES REGISTERED PURSUANT TO SECTION 12(B) OF THE ACT:

Title of each class	**Name of each exchange on which registered**
Common Stock, without par value	**New York Stock Exchange, Inc.**
Preference Stock Purchase Rights	**New York Stock Exchange, Inc.**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ¨ No x

Estimated aggregate market value of the common equity held by nonaffiliates of the registrant at June 30, 2005	$ 27,467,000,000
Number of shares of Common Stock, without par value, outstanding at February 28, 2006	928,185,106

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Explanatory Note

This Amendment No. 2 to the Annual Report on Form 10-K of Duke Energy Corporation (Duke Energy) for the fiscal year ended December 31, 2005 is being filed for the purpose of providing separate audited financial statements of TEPPCO Partners, L.P. in accordance with Rule 3-09 of Regulation S-X. These audited financial statements are included in Item 15, Exhibits and Financial Statement Schedules. Otherwise, this amendment does not update or modify in any way the financial position, results of operations, cash flows or the disclosures in Duke Energy s Annual Report on Form 10-K for the fiscal year ended December 31, 2005, and does not reflect events occurring after the original filing date of March 3, 2006.

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements

The following financial statements and related notes were filed as part of Duke Energy s Form 10-K filed March 3, 2006:

Report of Independent Registered Public Accounting Firm

Consolidated Statements of Income for the years ended December 31, 2005, 2004 and 2003

Consolidated Balance Sheets as of December 31, 2005 and 2004

Consolidated Statements of Cash Flows for the years ended December 31, 2005, 2004 and 2003

Consolidated Statements of Common Stockholder s Equity and Comprehensive Income (Loss) for the years ended December 31, 2005, 2004 and 2003

Notes to Consolidated Financial Statements

(b) Financial Statement Schedules

(i) The following financial statement schedules were filed as part of Duke Energy s Form 10-K filed March 3, 2006:

Report of Independent Registered Public Accounting Firm

Schedule II Valuation and Qualifying Accounts and Reserves

ii) The following financial statement schedules were filed as part of Duke Energy s Amendment No. 1 to Form 10-K/A pursuant to Rule 3-09 of Regulation S-X:

Audited Financial Statements of Duke Energy Field Services, LLC for the year ended December 31, 2005

Consolidated Financial Statement Schedule II of Duke Energy Field Services, LLC Valuation and Qualifying Accounts and Reserves for the Year Ended December 31, 2005

(iii) The following financial statement schedules are included herein this Duke Energy Form 10-K/A pursuant to Rule 3-09 of Regulation S-X:

Management s Annual Report on Internal Control over Financial Reporting of TEPPCO Partners, L.P.

Reports of Independent Registered Public Accounting Firm

Audited Consolidated Financial Statements of TEPPCO Partners, L.P.

All other schedules are omitted because they are not required, or because the required information is included in the Consolidated Financial Statements or Notes.

(c) Exhibits

12.1 Statement of Computation of Ratio of Earnings to Fixed Charges for TEPPCO Partners, L.P.

31.1 Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

31.2 Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

32.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

32.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: April 3, 2006

DUKE ENERGY CORPORATION

(Registrant)

By: /s/ PAUL M. ANDERSON
Paul M. Anderson

Chairman of the Board

and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

(i) Principal executive officer:
Paul M. Anderson

Chairman of the Board and Chief Executive Officer

(ii) Principal financial officer:
David L. Hauser

Group Vice President and Chief Financial Officer

(iii) Principal accounting officer:
Steven K. Young

Vice President and Controller

(iv) A majority of the Directors:
Roger Agnelli

Paul M. Anderson

William Barnet, III

G. Alex Bernhardt, Sr.

William T. Esrey

Ann Maynard Gray

James H. Hance Jr.

Dennis R. Hendrix

A. Max Lennon

James G. Martin

Michael E.J. Phelps

James T. Rhodes

Date: April 3, 2006

David L. Hauser, by signing his name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

By:	/s/ DAVID L. HAUSER Attorney-In-Fact

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Management s Annual Report on Internal Control over Financial Reporting

The management of Texas Eastern Products Pipeline Company, LLC, (the General Partner), the General Partner of TEPPCO Partners, L.P. (the Partnership), is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Partnership s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The Partnership s internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Partnership;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorizations of management and directors of the Partnership; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Partnership s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2005. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework.

Based on the assessment and those criteria, management believes that the Partnership maintained effective internal control over financial reporting as of December 31, 2005.

The Partnership s registered public accounting firm has issued an attestation report on management s assessment of the Partnership s internal control over financial reporting. That report appears below.

/s/ LEE W. MARSHALL, SR.
Lee W. Marshall, Sr.
Acting Chief Executive Officer and Chairman of the Board
Texas Eastern Products Pipeline Company, LLC, General Partner

/s/ WILLIAM G. MANIAS
William G. Manias
Vice President and Chief Financial Officer
Texas Eastern Products Pipeline Company, LLC, General Partner

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Report of Independent Registered Public Accounting Firm

To the Partners of

TEPPCO Partners, L.P.:

We have audited management s assessment, included in the accompanying report titled Management s Annual Report on Internal Control over Financial Reporting included in Item 9A, that TEPPCO Partners, L.P. maintained effective 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 Commissions (COSO). TEPPCO Partners, L.P. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of TEPPCO Partners, L.P. s internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that TEPPCO Partners, L.P. maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, TEPPCO Partners, L.P. maintained, in all material respects, effective 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).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), 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, and our report dated February 28, 2006, expressed an unqualified opinion on those consolidated financial statements. Our report contains a separate paragraph that states that as discussed in Note 20 to the consolidated financial statements, TEPPCO Partners, L.P. 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.

/s/ KPMG LLP

Houston, Texas

February 28, 2006

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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.

/s/ KPMG LLP

Houston, Texas
February 28, 2006

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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.

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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	$ 8,072,287	$ 5,434,127	$ 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	71,026	70,346	54,430
Total operating revenues	8,618,488	5,958,192	4,255,832
Costs and expenses:			
Purchases of petroleum products	7,995,433	5,372,971	3,711,207
Operating, general and administrative	219,487	220,647	198,478
Operating fuel and power	48,972	48,139	41,362
Depreciation and amortization	111,341	112,894	100,728
Taxes other than income taxes	20,740	17,461	15,597
Gains on sales of assets	(668)	(1,053)	(3,948)
Total costs and expenses	8,395,305	5,771,059	4,063,424
Operating income	223,183	187,133	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
Net income	$ 162,551	$ 138,548	$ 121,780
Net Income Allocation:			
Limited Partner Unitholders	$ 114,972	$ 98,580	$ 86,357
Class B Unitholder			1,754
General Partner	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	$ 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 operating activities:			
Depreciation and amortization	111,341	112,894	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	(950)	(3,461)	(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 operating activities	254,505	267,167	242,424
Cash flows from 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)	(164,147)	(140,517)
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.

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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.

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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.

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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.

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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.

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.

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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.

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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.

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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.

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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.

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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.

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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

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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

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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 AND DISPOSITIONS

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.

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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.

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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.

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.

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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	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	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).

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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.
(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.

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(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.

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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.

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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
2008	103.755%
2009	103.380%
2010	103.004%
2011	102.629%
2012	102.253%
2013	101.878%
2014	101.502%
2015	101.127%
2016	100.751%
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.

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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:

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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)

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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):

	December 31,	
Asset Category	**2005**	**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.

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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 up gradient 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.

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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 PPI Index 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.

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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).

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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 trunk line 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.

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	$ 10,479	$ 8,072,610	$ (323)	$ 8,072,287
Operating revenues	287,191	48,108	214,146	549,445	(3,244)	546,201
Purchases of petroleum products		7,989,682	8,995	7,998,677	(3,244)	7,995,433
Operating expenses, including power	159,784	70,340	59,398	289,522	(323)	289,199
Depreciation and amortization expense	39,403	17,161	54,777	111,341		111,341
Gains on sales of assets	(139)	(118)	(411)	(668)		(668)
Operating income	88,143	33,174	101,866	223,183		223,183
Equity earnings (losses)	(2,984)	23,078		20,094		20,094
Other income, net	755	156	224	1,135		1,135
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	$ 7,295	$ 5,434,127	$	$ 5,434,127
Operating revenues	279,400	49,163	198,709	527,272	(3,207)	524,065
Purchases of petroleum products		5,370,234	5,944	5,376,178	(3,207)	5,372,971
Operating expenses, including power	165,528	60,893	59,826	286,247		286,247
Depreciation and amortization expense	43,135	13,130	56,629	112,894		112,894
Gains on sales of assets	(526)	(527)		(1,053)		(1,053)
Operating income	71,263	32,265	83,605	187,133		187,133
Equity earnings (losses)	(6,544)	28,692		22,148		22,148
Other income, net	787	406	127	1,320		1,320
Earnings before interest	$ 65,506	$ 61,363	$ 83,732	$ 210,601	$	$ 210,601

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	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	45,075	163,453	694	164,147
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	67,882	140,370	147	140,517
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.

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

Balance at December 31, 2002 (unaudited) (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 (in thousands)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	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

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	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 (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$	$ 453,398	$ 8,168,657	$ (3,567)	$ 8,618,488
Costs and expenses		295,376	8,104,164	(3,567)	8,395,973
Gains on sales of assets		(551)	(117)		(668)
Operating income		158,573	64,610		223,183
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
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 (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$	$ 430,162	$ 5,531,237	$ (3,207)	$ 5,958,192
Costs and expenses		301,568	5,473,751	(3,207)	5,772,112
Gains on sales of assets		(526)	(527)		(1,053)
Operating income		129,120	58,013		187,133
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

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

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	Year Ended December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Cash flows from operating activities					
Net income	$ 162,551	$ 162,551	$ 60,072	$ (222,623)	$ 162,551
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Depreciation and amortization		83,148	28,193		111,341
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)	(57,625)	22,884	53,571	(35,710)
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 (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Cash flows from operating activities					
Net income	$ 138,548	$ 138,548	$ 63,998	$ (202,546)	$ 138,548
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization		90,048	22,846		112,894
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)	29,679	(30,930)	151,690	(8,287)
Net cash provided by operating activities	74,331	257,619	63,595	(128,378)	267,167
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

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	Year Ended December 31, 2003 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
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 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.

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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	