UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2005

OR

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

Commission File No. 1-10403

TEPPCO Partners, L.P.

(Exact name of Registrant as specified in its charter)

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

2929 Allen Parkway
P.O. Box 2521
Houston, Texas 77252-2521
(Address of principal executive offices, including zip code)

(713) 759-3636
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☒   No o

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. Limited Partner Units outstanding as of October 28, 2005:   69,963,554

TEPPCO PARTNERS, L.P.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

TEPPCO PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS
(in thousands)

	September 30, 2005 (Unaudited)	December 31, 2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 72	$ 16,422
Accounts receivable, trade (net of allowance for doubtful accounts of $287 and $112)	849,968	553,628
Accounts receivable, related parties	5,322	11,845
Inventories	139,005	19,521
Other	63,483	42,138
Total current assets	1,057,850	643,554
Property, plant and equipment, at cost (net of accumulated depreciation and amortization of $454,787 and $407,670)	1,907,840	1,703,702
Equity investments	374,531	373,652
Intangible assets	385,119	407,358
Goodwill	16,944	16,944
Other assets	60,212	51,419
Total assets	$ 3,802,496	$ 3,196,629
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 851,206	$ 564,464
Accounts payable, related parties	9,858	24,654
Accrued interest	13,501	32,292
Other accrued taxes	18,736	13,309
Other	71,043	46,593
Total current liabilities	964,344	681,312
Senior Notes	1,122,317	1,127,226
Other long-term debt	460,500	353,000
Other liabilities and deferred credits	17,494	13,643
Commitments and contingencies		
Partners' capital:		
Accumulated other comprehensive income	35	—
General partner's interest	(50,889)	(33,006)
Limited partners' interests	1,288,695	1,054,454
Total partners' capital	1,237,841	1,021,448
Total liabilities and partners' capital	$ 3,802,496	$ 3,196,629

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004

Operating revenues:				
Sales of petroleum products	$ 2,370,710	$ 1,359,954	$ 5,721,536	$ 3,774,874
Transportation—Refined products	38,240	43,386	111,039	113,294
Transportation—LPGs	16,519	16,071	63,220	58,572
Transportation—Crude oil	10,001	9,288	28,215	28,164
Transportation—NGLs	11,829	10,430	33,435	31,022
Gathering—Natural gas	38,833	35,515	112,349	104,444
Other	17,664	15,366	50,987	52,265
Total operating revenues	2,503,796	1,490,010	6,120,781	4,162,635
Costs and expenses:				
Purchases of petroleum products	2,352,542	1,345,677	5,668,698	3,730,330
Operating, general and administrative	57,763	60,492	157,760	164,935
Operating fuel and power	12,538	13,464	35,154	36,459
Depreciation and amortization	30,960	30,277	83,015	84,508
Taxes—other than income taxes	5,954	3,868	15,662	13,993
Gains on sales of assets	(31)	(849)	(597)	(973)
Total costs and expenses	2,459,726	1,452,929	5,959,692	4,029,252
Operating income	44,070	37,081	161,089	133,383
Interest expense—net	(19,726)	(17,131)	(60,640)	(53,190)
Equity earnings	6,095	5,621	20,403	22,854
Other income—net	484	284	885	1,000
Net income	$ 30,923	$ 25,855	$ 121,737	$ 104,047
Net Income Allocation:				
Limited Partner Unitholders	$ 21,872	$ 18,396	$ 86,105	$ 74,032
General Partner	9,051	7,459	35,632	30,015
Total net income allocated	$ 30,923	$ 25,855	$ 121,737	$ 104,047
Basic and diluted net income per Limited Partner Unit	$ 0.31	$ 0.29	$ 1.29	$ 1.18
Weighted average Limited Partner Units outstanding	69,964	62,999	66,533	62,999

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(in thousands)

	Nine Months Ended September 30,	
	2005	2004
Cash flows from operating activities:		
Net income	$ 121,737	$ 104,047
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	83,015	84,508
Earnings in equity investments, net of distributions	7,775	16,571
Gains on sales of assets	(597)	(973)
Non-cash portion of interest expense	1,214	177
Increase in accounts receivable	(296,340)	(139,808)
(Increase) decrease in accounts receivable, related parties	6,523	(15,129)
Increase in inventories	(111,094)	(13,124)
Increase in other current assets	(21,002)	(2,855)
Increase in accounts payable and accrued expenses	289,130	135,446
Increase (decrease) in accounts payable, related parties	(14,796)	1,882
Other	(21,617)	3,191
Net cash provided by operating activities	43,948	173,933
Cash flows from investing activities:		
Proceeds from the sales of assets	510	1,202
Purchase of assets	(112,231)	(3,421)
Investment in Centennial Pipeline LLC	—	(1,500)
Investment in Mont Belvieu Storage Partners, L.P.	(2,635)	(20,161)
Capital expenditures	(148,063)	(110,998)

Net cash used in investing activities	(262,419)	(134,878)
Cash flows from financing activities:		
Proceeds from revolving credit facility	549,657	256,300
Repayments on revolving credit facility	(442,157)	(140,800)
Issuance of Limited Partner Units, net	278,830	—
Distributions paid	(184,209)	(174,399)
Net cash provided by (used in) financing activities	202,121	(58,899)
Net decrease in cash and cash equivalents	(16,350)	(19,844)
Cash and cash equivalents at beginning of period	16,422	29,469
Cash and cash equivalents at end of period	$ 72	$ 9,625
Non-cash investing activities:		
Net assets transferred to Mont Belvieu Storage Partners, L.P.	$ 1,429	$ —
Supplemental disclosure of cash flows:		
Cash paid for interest (net of amounts capitalized)	$ 78,504	$ 75,498

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
(Unaudited)
(in thousands, except Unit amounts)

	Outstanding Limited Partner Units	Accumulated General Partner's Interest	Limited Partners' Interests	Other Comprehensive Income	Total
Partners' capital at December 31, 2004	62,998,554	$ (33,006)	$ 1,054,454	$ —	$ 1,021,448
Issuance of Limited Partner Units, net	6,965,000	—	278,830	—	278,830
Net income allocation	—	35,632	86,105	—	121,737
Change in fair value of crude oil hedge	—	—	—	35	35
Cash distributions	—	(53,515)	(130,694)	—	(184,209)
Partners' capital at September 30, 2005	69,963,554	$ (50,889)	$ 1,288,695	$ 35	$ 1,237,841

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

NOTE 1. ORGANIZATION AND BASIS OF PRESENTATION

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." TEPPCO GP, Inc. ("TEPPCO GP"), our wholly owned subsidiary, is the general partner of our Operating Partnerships. We hold a 99.999% limited partner interest in the Operating Partnerships, and TEPPCO GP holds a 0.001% general partner interest. 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. 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. Through February 23, 2005, 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.

EPCO performs all management 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 will continue to provide some administrative services for us for a period of time until we assume 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.

In connection with our formation in 1990, the Company received 2,500,000 Deferred Participation Interests ("DPIs"). Effective April 1, 1994, the DPIs began participating in distributions of cash and allocations of profit and loss in a manner identical to Limited Partner Units and are treated as Limited Partner Units for purposes of this Report. These DPIs 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 DPIs for approximately $100.0 million.

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.

The accompanying unaudited consolidated financial statements reflect all adjustments that are, in the opinion of our management, of a normal and recurring nature and necessary for a fair statement of our financial position as of September 30, 2005, and the results of our operations and cash flows for the periods presented. The results of operations for the three months and nine months ended September 30, 2005, are not necessarily indicative of results of our operations for the full year 2005. You should read these interim financial statements in conjunction with our consolidated financial statements and notes thereto presented in the TEPPCO Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2004. We have reclassified certain amounts from prior periods to conform to the current presentation.

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."

Net Income Per Unit

Basic net income per Limited Partner Unit ("Unit" or "Units") is computed by dividing our net income, after deduction of the General Partner's interest, by the weighted average number of Units outstanding (a total of 70.0 million and 66.5 million Units for the three months and nine months ended September 30, 2005, respectively, and 63.0 million Units for the three months and nine months ended September 30, 2004). The General Partner's percentage interest in our net income is based on its percentage of cash distributions from Available Cash for each period (see Note 9. Partners' Capital and Distributions). The General Partner was allocated $9.1 million (representing 29.27%) and $7.5 million (representing 28.85%) of our net income for the three months ended September 30, 2005 and 2004, respectively, and $35.6 million (representing 29.27%) and $30.0 million (representing 28.85%) of our net income for the nine months ended September 30, 2005 and 2004, respectively. 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 equaled basic net income per Unit for each of the three-month and nine-month periods ended September 30, 2005 and 2004, as there were no dilutive instruments outstanding.

New Accounting Pronouncements

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

In November 2004, the Emerging Issues Task Force ("EITF") reached consensus in EITF 03-13, *Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations*, to clarify whether a component of an enterprise that is either disposed of or classified as held for sale qualifies for income statement presentation as discontinued operations. The FASB ratified the consensus on November 30, 2004. The consensus is to be applied prospectively with regard to a component of an enterprise that is either disposed of or classified as held for sale in reporting

periods beginning after December 15, 2004. The consensus may be applied retrospectively for previously reported operating results related to disposal transactions initiated within an enterprise's reporting period that included the date that this consensus was ratified. The adoption of EITF 03-13 did not have an effect on our financial position, results of operations or cash flows.

In March 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* ("FIN 47"). FIN 47 clarifies that the term, conditional asset retirement obligation as used in SFAS No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional upon a future event that may or may not be within the control of the entity. Even though uncertainty about the timing and/or method of settlement exists and may be conditional upon a future event, the obligation to perform the asset retirement activity is unconditional. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing and/or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred generally upon acquisition, construction, or development or through the normal operation of the asset. SFAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective no later than the end of reporting periods ending after December 15, 2005, and early adoption of FIN 47 is encouraged. We will adopt FIN 47 in the fourth quarter of 2005. We do not believe that the adoption of FIN 47 will 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 are currently evaluating what impact EITF 04-5 will have on our financial statements, but at this time we do not believe that the adoption of EITF 04-5 will have a material effect on our financial position, results of operations or cash flows.

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

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

In September 2005, the EITF reached consensus in EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, to define when a purchase and a sale of inventory with the same party that operates in the same line of business should be considered a single nonmonetary transaction subject to APB Opinion No. 29, *Accounting for Nonmonetary Transactions*. Two or more inventory transactions with the same party should be combined if they are entered into in contemplation of one another. The consensus 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 2. 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.

At September 30, 2005, and December 31, 2004, we have $16.9 million of unamortized goodwill and $25.5 million of excess investment in our equity investment in Seaway Crude Pipeline Company (equity method goodwill). The excess investment is included in our equity investments account at September 30, 2005. The following table presents the carrying amount of goodwill and equity method goodwill at September 30, 2005, and December 31, 2004, by business segment (in thousands):

	Downstream Segment	Midstream Segment	Upstream Segment	Segments Total
Goodwill	$ —	$ 2,777	$ 14,167	$ 16,944
Equity method goodwill	—	—	25,502	25,502

Other Intangible Assets

The following table reflects the components of intangible assets being amortized at September 30, 2005, and December 31, 2004 (in thousands):

	September 30, 2005		December 31, 2004	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible assets being amortized:				
Gathering and transportation agreements	$ 464,337	$ (111,367)	$ 464,337	$ (91,262)
Fractionation agreement	38,000	(14,250)	38,000	(12,825)
Other	10,226	(1,827)	12,262	(3,154)
Total	$ 512,563	$ (127,444)	$ 514,599	$ (107,241)

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 $8.2 million and $8.6 million for the three months ended September 30, 2005 and 2004, respectively, and $22.3 million and $25.0 million for the nine months ended September 30, 2005 and 2004, respectively.

The values assigned to our intangible assets for natural gas gathering contracts on the Jonah Gas Gathering Company (“Jonah”) and the Val Verde Gas Gathering Company (“Val Verde”) systems are amortized on a unit-of-production basis, based upon the actual throughput of the systems over 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 with DEFS 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 values assigned to our crude supply and transportation intangible customer contracts are being amortized on a unit-of-production basis.

At September 30, 2005, we have $33.4 million of excess investment in our equity investment in Centennial Pipeline LLC, which was created upon its formation. The excess investment is included in our equity investments account at September 30, 2005. This excess investment is accounted for as an intangible asset with an indefinite life. We assess the intangible asset for impairment on an annual basis.

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

2005	$ 29,573
2006	29,621
2007	33,109
2008	33,219
2009	31,213

NOTE 3. PROPERTY, PLANT AND EQUIPMENT

We evaluate impairment of long-lived assets in accordance with 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 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 fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell.

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 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 fair value of the system.

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.

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 fair value of the facility.

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. From January 2004 through April 2004, we recognized an increase in interest expense of $2.9 million 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 nine months ended September 30, 2005 and 2004, we recognized reductions in interest expense of $4.6 million and $7.5 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. During the quarter ended September 30, 2005, 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 gain of approximately $1.3 million and $3.4 million at September 30, 2005, and December 31, 2004, respectively.

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 September 30, 2005, the unamortized balance of the deferred gains was $33.5 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.

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 are integrating 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 will 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 two-bay truck loading rack in North Little Rock, Arkansas, for $6.8 million from Exxon Mobil Corporation. The assets include three storage tanks and a two-bay truck loading rack. We funded the purchase through borrowings under our revolving credit facility. We allocated the purchase price to property, plant and equipment and inventory, and we accounted for the acquisition of these assets under the purchase method of accounting. The terminal serves the central Arkansas refined products market and complements our existing Downstream Segment infrastructure in North Little Rock, Arkansas.

Genco Assets

On July 15, 2005, we acquired from Texas Genco LLC ("Genco") all of its interests in certain companies that own a 90-mile pipeline system and 5.5 million barrels of storage capacity for $62.1 million. We funded the purchase through borrowings under our revolving credit facility. We allocated the purchase price to property, plant

and equipment, and we accounted for the acquisition of these assets under the purchase method of accounting. This acquisition was made as part of an expansion of our refined products origin capabilities in the Houston, Texas, and Texas City, Texas, areas. The assets of the purchased companies will be integrated into our Downstream Segment origin infrastructure in Texas City and Baytown, Texas. 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 the Texas Gulf Coast refining and logistics system.

NOTE 6. 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 September 30, 2005, and December 31, 2004. The major components of inventories were as follows (in thousands):

	September 30, 2005	December 31, 2004
Crude oil (1)	$ 114,407	$ 3,690
Refined products	7,335	5,665
LPGs	2,511	—
Lubrication oils and specialty chemicals	5,015	4,002
Materials and supplies	6,774	6,135
Other	2,963	29
Total	$ 139,005	$ 19,521

(1) At September 30, 2005, substantially all of our crude oil inventory was subject to forward sales contracts.

NOTE 7. EQUITY INVESTMENTS

Through one of our indirect wholly owned subsidiaries, we own a 50% ownership interest in Seaway Crude Pipeline Company ("Seaway"). The remaining 50% interest is owned by ConocoPhillips. 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 the Seaway partnership. 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 nine months ended September 30, 2005 and 2004, we received distributions from Seaway of $17.5 million and $30.9 million, respectively.

TE Products owns a 50% ownership interest in Centennial Pipeline Company LLC ("Centennial"), and Marathon Petroleum Company LLC ("Marathon") owns the remaining 50% interest. Centennial owns an interstate refined petroleum products pipeline extending from the upper Texas Gulf Coast to central Illinois. During the nine months ended September 30, 2005, TE Products has not invested any additional funds in Centennial. During the nine months ended September 30, 2004, TE Products invested an additional $1.5 million in Centennial, which is included in the equity investment balance at September 30, 2005. 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 transportation, terminaling and storage. MB Storage has no commodity trading activity. TE Products operates the facilities for MB Storage.

For the year ended December 31, 2005, TE Products will receive the first $1.7 million per quarter (or $6.78 million on an annual basis) of MB Storage's income before depreciation expense, as defined in the operating agreement. For the year ended December 31, 2004, TE Products received the first $1.8 million per quarter (or $7.15 million on an annual basis) of MB Storage's income before depreciation expense. TE Products' share of MB Storage's earnings is adjusted annually by the partners of MB Storage. Any amount of MB Storage's annual income before depreciation expense in excess of $6.78 million for 2005 and $7.15 million for 2004 is allocated evenly between TE Products and Louis Dreyfus. Depreciation expense on assets each party originally contributed to MB Storage is allocated between TE Products and Louis Dreyfus based on the net book value of the assets contributed. Depreciation expense on assets constructed or acquired by MB Storage subsequent to formation is allocated evenly between TE Products and Louis Dreyfus. For the nine months ended September 30, 2005 and 2004, TE Products' sharing ratio in the earnings of MB Storage was approximately 64.3% and 72.3%, respectively. During the nine months ended September 30, 2005, TE Products received distributions of $10.7 million from MB Storage and contributed $4.0 million to MB Storage, which includes a combination of non-cash asset transfers of $1.4 million and cash contributions of $2.6 million. During the nine months ended September 30, 2004, TE Products received distributions of $8.5 million from MB Storage and contributed $20.2 million to MB Storage, of which $16.5 million was used to acquire storage assets in April 2004.

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 nine months ended September 30, 2005 and 2004, is presented below (in thousands):

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Revenues	$ 123,224	$ 115,843
Net income	39,896	44,344

Summarized combined balance sheet information for Seaway, Centennial and MB Storage as of September 30, 2005, and December 31, 2004, is presented below (in thousands):

	September 30, 2005	December 31, 2004
Current assets	$ 74,863	$ 59,314
Noncurrent assets	629,143	633,222
Current liabilities	52,805	41,209
Long-term debt	140,000	140,000
Noncurrent liabilities	18,952	20,440
Partners' capital	492,249	490,887

NOTE 8. 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 a premium.

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 September 30, 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 September 30, 2005, we were in compliance with the covenants of these Senior Notes.

On January 30, 2003, we completed the issuance of $200.0 million principal amount of 6.125% Senior Notes due 2013. The 6.125% Senior Notes were issued at a discount of $1.4 million and are being accreted to their face value over the term of the notes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 6.125% Senior Notes contains covenants including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of September 30, 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 September 30, 2005, and December 31, 2004 (in millions):

		Fair Value	
	Face Value	September 30, 2005	December 31, 2004
6.45% TE Products Senior Notes, due January 2008	$ 180.0	$ 185.0	$ 187.1
7.625% Senior Notes, due February 2012	500.0	555.3	569.6
6.125% Senior Notes, due February 2013	200.0	206.3	210.2
7.51% TE Products Senior Notes, due January 2028	210.0	223.9	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. Interest Rate Swaps).

Revolving Credit 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 9. Partners’ Capital and Distributions) and complete mergers, acquisitions and sales of assets. 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 again 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. Organization and Basis of Presentation). 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 9. Partners’ Capital and Distributions). At September 30, 2005, $460.5 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 4.6%. At September 30, 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 September 30, 2005, and December 31, 2004 (in thousands):

	September 30, 2005	December 31, 2004
Credit Facilities:		
Revolving Credit Facility, due October 2009	$ 460,500	$ 353,000
6.45% TE Products Senior Notes, due January 2008	179,929	179,906
7.625% Senior Notes, due February 2012	498,604	498,438
6.125% Senior Notes, due February 2013	198,952	198,845
7.51% TE Products Senior Notes, due January 2028	210,000	210,000
Total borrowings	1,547,985	1,440,189
Adjustment to carrying value associated with hedges of fair value	34,832	40,037
Total Credit Facilities	$ 1,582,817	$ 1,480,226

NOTE 9. PARTNERS’ CAPITAL AND DISTRIBUTIONS

Equity Offering

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 Company receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds as follows:

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

The following table reflects the allocation of total distributions paid during the nine months ended September 30, 2005 and 2004 (in thousands, except per Unit amounts):

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Limited Partner Units	$ 130,694	$ 124,422
General Partner Ownership Interest	2,667	2,539
General Partner Incentive	50,848	47,438
Total Cash Distributions Paid	$ 184,209	$ 174,399
Total Cash Distributions Paid Per Unit	$ 2.00	$ 1.975

On November 7, 2005, we will pay a cash distribution of $0.675 per Unit for the quarter ended September 30, 2005. The third quarter 2005 cash distribution will total $66.9 million.

General Partner's Interest

As of September 30, 2005, and December 31, 2004, we had deficit balances of $50.9 million and $33.0 million, respectively, in our General Partner's equity account. These negative balances do not represent assets to us and do not represent obligations 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 Statement of Partners' Capital for a detail of the General Partner's equity account). For the nine months ended September 30, 2005, the General Partner was allocated $35.6 million (representing 29.27%) of our net income and received $53.5 million 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 September 30, 2005, and December 31, 2004, the General Partner's Capital Account balance substantially exceeded this requirement.

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

Cash distributions that we make during a period may exceed our net income for the period. We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. Cash distributions in excess of net income allocations and capital contributions during the year ended December 31, 2004, and the nine months ended September 30, 2005, resulted in deficits in the General Partner's equity account at December 31, 2004, and September 30, 2005. 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 10. EMPLOYEE BENEFIT PLANS

Retirement Plans

The TEPPCO Retirement Cash Balance Plan ("TEPPCO RCBP") is a non-contributory, trustee-administered pension plan. In addition, the TEPPCO Supplemental Benefit Plan ("TEPPCO SBP") is a non-contributory, nonqualified, defined benefit retirement plan, in which certain executive officers participate. 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 is a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit based upon pay credits and current interest credits. The pay credits are based on a participant's salary, age and service. We use 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 will be frozen, participants will not receive additional pay credits after that date, and all plan participants will be 100% vested regardless of their years of service. The TEPPCO RCBP plan will be terminated effective December 31, 2005, 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 will own the annuity, absolving us of any future obligation to the participant. Participants in the TEPPCO SBP will receive pay credits through November 30, 2005, and will receive 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 expect to record additional settlement charges of approximately $0.2 million in the fourth quarter of 2005 relating to the TEPPCO SBP and approximately $3.2 million in 2006 relating to the TEPPCO RCBP for any existing unrecognized losses upon the plan termination and final distribution of the assets to the plan participants.

The components of net pension benefits costs for the TEPPCO RCBP and the TEPPCO SBP for the three months and nine months ended September 30, 2005 and 2004, were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Service cost benefit earned during the period	$ 1,147	$ 913	$ 3,246	$ 2,739
Interest cost on projected benefit obligation	233	180	701	540
Expected return on plan assets	(76)	(220)	(595)	(660)
Amortization of prior service cost	1	2	4	6
Recognized net actuarial loss	37	14	92	42
SFAS 88 curtailment charge	—	—	50	—
Net pension benefits costs	$ 1,342	$ 889	$ 3,498	$ 2,667

Other Postretirement Benefits

We provide certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis ("TEPPCO OPB"). Employees become eligible for these benefits if they meet certain age and service requirements at retirement, as defined in the plans. We provide a fixed dollar contribution, which does not increase from year to year, towards retired employee medical costs. The retiree pays all health care cost increases due to medical inflation. We use 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 will receive them through December 31, 2005, however, effective December 31, 2005, these benefits will be terminated. In June 2005, 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 $2.6 million in our accumulated postretirement obligation, partially offset by a curtailment charge of approximately $1.0 million related to the accelerated recognition of the unrecognized prior service costs. The net effect of these curtailment adjustments was to reduce 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 three and nine months ended September 30, 2005 and 2004, were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Service cost benefit earned during the period	$ —	$ 41	$ 81	$ 123
Interest cost on accumulated postretirement benefit obligation	—	38	69	114
Amortization of prior service cost	—	32	53	96

Recognized net actuarial loss	—	—	4	—
SFAS 106 curtailment credit	—	—	(1,676)	—
Net postretirement benefits costs	$ —	$ 111	$ (1,469)	$ 333

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.

Estimated Future Benefit Contributions

We expect to contribute approximately $1.1 million to our retirement plans and other postretirement benefit plans in 2005.

NOTE 11. SEGMENT INFORMATION

We have three reporting segments:

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

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 in the Northeast 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 7. Equity Investments).

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale of the crude oil to local refineries, marketers or other end users. Our Upstream Segment also includes our equity investment in Seaway (see Note 7. Equity Investments). Seaway consists of large diameter pipelines that transport crude oil from Seaway’s marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

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

The table below includes financial information by reporting segment for the three months and nine months ended September 30, 2005 and 2004 (in thousands):

	Three Months Ended September 30, 2005					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 2,367,984	$ 2,880	$ 2,370,864	$ (154)	$ 2,370,710
Operating revenues	66,094	12,750	54,430	133,274	(188)	133,086
Purchases of petroleum products	—	2,350,107	2,623	2,352,730	(188)	2,352,542
Operating expenses, including power	41,405	18,956	16,048	76,409	(154)	76,255
Depreciation and amortization expense	10,098	6,471	14,391	30,960	—	30,960
Gains on sales of assets	(24)	(7)	—	(31)	—	(31)
Operating income	14,615	5,207	24,248	44,070	—	44,070
Equity earnings	524	5,571	—	6,095	—	6,095
Other income, net	306	103	75	484	—	484

Earnings before interest	$ 15,445	$ 10,881	$ 24,323	$ 50,649	$ —	$ 50,649

	Three Months Ended September 30, 2004					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 1,358,220	$ 1,734	$ 1,359,954	$ —	$ 1,359,954
Operating revenues	68,546	11,866	49,961	130,373	(317)	130,056
Purchases of petroleum products	—	1,344,613	1,381	1,345,994	(317)	1,345,677
Operating expenses, including power	43,419	17,804	16,601	77,824	—	77,824
Depreciation and amortization expense	12,818	3,268	14,191	30,277	—	30,277
Gains on sales of assets	(472)	(377)	—	(849)	—	(849)
Operating income	12,781	4,778	19,522	37,081	—	37,081
Equity earnings (losses)	(322)	5,943	—	5,621	—	5,621
Other income, net	203	60	21	284	—	284
Earnings before interest	$ 12,662	$ 10,781	$ 19,543	$ 42,986	$ —	$ 42,986

	Nine Months Ended September 30, 2005					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 5,714,353	$ 7,337	$ 5,721,690	$ (154)	$ 5,721,536
Operating revenues	207,699	36,161	157,622	401,482	(2,237)	399,245
Purchases of petroleum products	—	5,665,136	5,799	5,670,935	(2,237)	5,668,698
Operating expenses, including power	117,271	49,615	41,844	208,730	(154)	208,576
Depreciation and amortization expense	29,460	13,623	39,932	83,015	—	83,015
Gains on sales of assets	(131)	(59)	(407)	(597)	—	(597)
Operating income	61,099	22,199	77,791	161,089	—	161,089
Equity earnings	574	19,829	—	20,403	—	20,403
Other income, net	576	132	177	885	—	885
Earnings before interest	$ 62,249	$ 42,160	$ 77,968	$ 182,377	$ —	$ 182,377

	Nine Months Ended September 30, 2004					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 3,770,006	$ 4,868	$ 3,774,874	$ —	$ 3,774,874
Operating revenues	205,719	37,430	146,994	390,143	(2,382)	387,761
Purchases of petroleum products	—	3,728,345	4,367	3,732,712	(2,382)	3,730,330
Operating expenses, including power	122,020	46,880	46,487	215,387	—	215,387
Depreciation and amortization expense	31,106	9,381	44,021	84,508	—	84,508
Gains on sales of assets	(489)	(484)	—	(973)	—	(973)
Operating income	53,082	23,314	56,987	133,383	—	133,383
Equity earnings (losses)	(2,069)	24,923	—	22,854	—	22,854
Other income, net	648	257	95	1,000	—	1,000
Earnings before interest	$ 51,661	$ 48,494	$ 57,082	$ 157,237	$ —	$ 157,237

The following table shows total assets, capital expenditures and non-cash investing activities for each segment as of and for the periods ended September 30, 2005, and December 31, 2004 (in thousands):

	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
September 30, 2005:						
Total assets	$ 1,052,883	$ 1,514,351	$ 1,241,780	$ 3,809,014	$ (6,518)	$ 3,802,496
Capital expenditures	38,617	30,677	78,089	147,383	680	148,063
Non-cash investing activities	1,429	—	—	1,429	—	1,429

December 31, 2004:						
Total assets	$ 967,917	$ 1,070,477	$ 1,184,184	$ 3,222,578	$ (25,949)	$ 3,196,629
Capital expenditures	80,930	37,448	45,075	163,453	694	164,147

The following table reconciles the segments' total earnings before interest to consolidated net income for the three months and nine months ended September 30, 2005 and 2004 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Earnings before interest	$ 50,649	$ 42,986	$ 182,377	$ 157,237
Interest expense—net	(19,726)	(17,131)	(60,640)	(53,190)
Net income	$ 30,923	$ 25,855	$ 121,737	$ 104,047

NOTE 12. 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. The settlement terms included a $2.0 million payment to the plaintiffs, which was accrued at December 31, 2004.

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.

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. Our discovery is at an early stage in this matter. 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. 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. Although we believe our operations are in material compliance with applicable environmental laws and regulations, risks of significant costs and liabilities are inherent in pipeline operations, and we cannot assure you that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly strict environmental 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. We believe that changes in environmental laws and regulations will not have a material adverse effect on our financial position, results of operations or cash flows in the near term.

On March 26, 2004, an initial 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 standalone 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 December 2, 2004, the FERC issued a Request for Comments seeking comments on whether the court’s ruling applies only to the specific facts of the SFPP, L.P. proceeding or also extends to other capital structures involving partnerships and other forms of ownership. 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 June 1, 2005, the FERC issued an Order on Remand in the SFPP, L.P. proceedings holding the Policy Statement would apply in that case and requesting briefs on whether additional evidence was necessary to apply it. Briefs have been filed but the FERC has not yet acted on them. The ultimate outcome of the FERC’s inquiry on income tax allowance should not affect our current rates and rate structure because our rates are not based on cost-of-service methodology. However, the outcome of the income tax allowance would become relevant to us should we (i) elect in the future to use cost-of-service to support our rates, or (ii) be required to use such methodology to defend our indexed rates.

In 1994, the Louisiana Department of Environmental Quality (“LDEQ”) issued a compliance order for environmental contamination at our Arcadia, Louisiana facility. In 1999, our Arcadia facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this contamination. Effective March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility. This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility. At September 30, 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 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.

At September 30, 2005, we have an accrued liability of $4.0 million related to various sites requiring environmental remediation activities. We do not expect that the completion of remediation programs associated with our activities will have a future material adverse effect on our financial position, results of operations or cash flows.

Other

Centennial entered into credit facilities totaling $150.0 million, and as of September 30, 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 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 September 30, 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 $4.7 million obligation, which represents the present value of the estimated amount that we would have to pay under the guarantee. In the event that a catastrophic event occurred and we were required to contribute cash to Centennial, contributions exceeding our deductible may be covered by our insurance.

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 FTC has contacted the General Partner requesting data. The General Partner intends to cooperate fully with any such investigations and inquiries requested by the FTC or any other regulatory authorities.

NOTE 13. 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 nine months ended September 30, 2005, the component of comprehensive income was due to a crude oil hedge. The crude oil hedge matures in December 2006. While the crude oil hedge is in effect, changes in the fair value of the crude oil hedge, to the extent the hedge is effective, are recognized in other comprehensive income until they are recognized in net income in future periods. As of and for the nine months ended September 30, 2004, the component of comprehensive income were due to the interest rate swap related to our variable rate revolving credit facility, which was designated as a cash flow hedge. The interest rate swap matured in April 2004. While the interest rate swap was in effect, changes in the fair value of the cash flow hedge, to the extent the hedge was effective, were recognized in other comprehensive income until the hedge interest costs were recognized in net income.

The table below reconciles reported net income to total comprehensive income for the three months and nine months ended September 30, 2005 and 2004 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Net income	$ 30,923	$ 25,855	$ 121,737	$ 104,047
Net income on cash flow hedges	35	—	35	2,902
Total comprehensive income	$ 30,958	$ 25,855	$ 121,772	$ 106,949

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

Balance at December 31, 2004	$ —
Change in fair value of crude oil cash flow hedge	35
Balance at September 30, 2005	$ 35

NOTE 14. 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.

	September 30, 2005				
	TEPPCO Partners, L .P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Assets					
Current assets	$ 25,988	$ 76,609	$ 978,222	$ (22,969)	$ 1,057,850
Property, plant and equipment—net	—	1,294,104	613,736	—	1,907,840
Equity investments	1,237,834	475,539	206,538	(1,545,380)	374,531
Intercompany notes receivable	1,189,428	—	—	(1,189,428)	—
Intangible assets	—	352,548	32,571	—	385,119
Other assets	5,237	24,064	47,855	—	77,156
Total assets	$ 2,458,487	$ 2,222,864	$ 1,878,922	$ (2,757,777)	$ 3,802,496
Liabilities and partners' capital					
Current liabilities	$ 27,683	$ 110,933	$ 849,608	$ (23,880)	$ 964,344
Long-term debt	1,191,557	391,260	—	—	1,582,817
Intercompany notes payable	—	581,150	608,279	(1,189,429)	—
Other long term liabilities	1,441	14,843	1,210	—	17,494
Total partners' capital	1,237,806	1,124,678	419,825	(1,544,468)	1,237,841
Total liabilities and partners' capital	$ 2,458,487	$ 2,222,864	$ 1,878,922	$ (2,757,777)	$ 3,802,496

	December 31, 2004				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
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	1,021,476	430,688	203,796	(1,282,308)	373,652
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	$ 2,155,615	$ 2,122,796	$ 1,347,488	$ (2,429,270)	$ 3,196,629
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	1,021,448	899,993	382,314	(1,282,307)	1,021,448
Total liabilities and partners' capital	$ 2,155,615	$ 2,122,796	$ 1,347,488	$ (2,429,270)	$ 3,196,629

	Three Months Ended September 30, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 107,728	$ 2,396,410	$ (342)	$ 2,503,796
Costs and expenses	—	77,759	2,382,340	(342)	2,459,757
Gains on sales of assets	—	(24)	(7)	—	(31)
Operating income	—	29,993	14,077	—	44,070
Interest expense—net	—	(12,476)	(7,250)	—	(19,726)
Equity earnings	30,923	13,071	5,571	(43,470)	6,095
Other income—net	—	335	149	—	484
Net income	$ 30,923	$ 30,923	$ 12,547	$ (43,470)	$ 30,923

	Three Months Ended September 30, 2004				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 106,776	$ 1,383,551	$ (317)	$ 1,490,010
Costs and expenses	—	81,291	1,372,804	(317)	1,453,778
Gains on sales of assets	—	(472)	(377)	—	(849)
Operating income	—	25,957	11,124	—	37,081
Interest expense—net	—	(11,625)	(5,506)	—	(17,131)
Equity earnings	25,855	11,304	5,943	(37,481)	5,621

Other income—net	—	219	65	—	284
Net income	$ 25,855	$ 25,855	$ 11,626	$ (37,481)	$ 25,855

	Nine Months Ended September 30, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
	(in thousands)				
Operating revenues	$ —	$ 329,310	$ 5,793,862	$ (2,391)	$ 6,120,781
Costs and expenses	—	214,807	5,747,873	(2,391)	5,960,289
Gains on sales of assets	—	(538)	(59)	—	(597)
Operating income	—	115,041	46,048	—	161,089
Interest expense—net	—	(39,751)	(20,889)	—	(60,640)
Equity earnings	121,737	45,767	19,829	(166,930)	20,403
Other income—net	—	680	205	—	885
Net income	$ 121,737	$ 121,737	$ 45,193	$ (166,930)	$ 121,737

	Nine Months Ended September 30, 2004				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
	(in thousands)				
Operating revenues	$ —	$ 317,477	$ 3,847,540	$ (2,382)	$ 4,162,635
Costs and expenses	—	226,138	3,806,469	(2,382)	4,030,225
Gains on sales of assets	—	(489)	(484)	—	(973)
Operating income	—	91,828	41,555	—	133,383
Interest expense—net	—	(35,636)	(17,554)	—	(53,190)
Equity earnings	104,047	47,144	24,923	(153,260)	22,854
Other income—net	—	711	289	—	1,000
Net income	$ 104,047	$ 104,047	$ 49,213	$ (153,260)	$ 104,047

	Nine Months Ended September 30, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
	(in thousands)				
Cash flows from operating activities					
Net income	$ 121,737	$ 121,737	$ 45,193	$ (166,930)	$ 121,737
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Depreciation and amortization	—	61,573	21,442	—	83,015
Earnings (losses) in equity investments, net of distributions	62,471	2,731	(2,339)	(55,088)	7,775
Gains on sales of assets	—	(538)	(59)	—	(597)
Changes in assets and liabilities and other	(108,054)	(52,386)	(113,346)	105,804	(167,982)
Net cash provided by (used in) operating activities	76,154	133,117	(49,109)	(116,214)	43,948
Cash flows from investing activities	(278,830)	(21,909)	(144,749)	183,069	(262,419)
Cash flows from financing activities	202,121	(124,614)	191,061	(66,447)	202,121
Net decrease in cash and cash equivalents	(555)	(13,406)	(2,797)	408	(16,350)
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	$ 3,561	$ 190	$ 29	$ (3,708)	$ 72

	Nine Months Ended September 30, 2004				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
	(in thousands)				
Cash flows from operating activities					
Net income	$ 104,047	$ 104,047	$ 49,213	$ (153,260)	$ 104,047
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	67,784	16,724	—	84,508
Earnings (losses) in equity investments,	71,149	(4,236)	5,977	(56,319)	16,571

net of distributions					
Gains on sales of assets	—	(489)	(484)	—	(973)
Changes in assets and liabilities and other	(133,125)	4,060	(27,902)	126,747	(30,220)
Net cash provided by operating activities	42,071	171,166	43,528	(82,832)	173,933
Cash flows from investing activities	(699)	(17,928)	(29,888)	(86,363)	(134,878)
Cash flows from financing activities	(58,899)	(165,268)	(16,898)	182,166	(58,899)
Net decrease in cash and cash equivalents	(17,527)	(12,030)	(3,258)	12,971	(19,844)
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	$ 2,217	$ 7,213	$ 2,412	$ (2,217)	$ 9,625

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

You should read the following review of our financial position and results of operations in conjunction with our Consolidated Financial Statements and the notes thereto. Material period-to-period variances in the consolidated statements of income are discussed under "Results of Operations." The "Financial Condition and Liquidity" section analyzes our cash flows and financial position. "Other Considerations" addresses trends, future plans and contingencies that are reasonably likely to materially affect our future liquidity or earnings. The Consolidated Financial Statements should be read in conjunction with the financial statements and related notes, together with our discussion and analysis of financial position and results of operations included in our Annual Report on Form 10-K for the year ended December 31, 2004.

Forward-Looking Statements

The matters discussed in this Report include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements that express belief, expectation, estimates or intentions, as well as those that are not statements of historical facts are forward-looking statements. The words "proposed", "anticipates", "potential", "may", "will", "could", "should", "expect", "estimate", "believe", "intend" and similar expressions are intended to identify forward-looking statements. Without limiting the broader description of forward-looking statements above, we specifically note that statements included in this document that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as estimated future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strengths, goals, expansion and growth of our business and operations, plans, references to future success, references to intentions as to future matters and other such matters are forward-looking statements. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. While we believe our expectations reflected in these forward-looking statements are reasonable, whether actual results and developments will conform with our expectations and predictions is subject to a number of risks and uncertainties, including general economic, market or business conditions, the opportunities (or lack thereof) that may be presented to and pursued by us, competitive actions by other pipeline companies, changes in laws or regulations and other factors, many of which are beyond our control. For example, the demand for refined products is dependent upon the price, prevailing economic conditions and demographic changes in the markets served, trucking and railroad freight, agricultural usage and military usage; the demand for propane is sensitive to the weather and prevailing economic conditions; the demand for petrochemicals is dependent upon prices for products produced from petrochemicals; the demand for crude oil and petroleum products is dependent upon the price of crude oil and the products produced from the refining of crude oil; and the demand for natural gas is dependent upon the price of natural gas and the locations in which natural gas is drilled. We are also subject to regulatory factors such as the amounts we are allowed to charge our customers for the services we provide on our regulated pipeline systems. Consequently, all of the forward-looking statements made in this document are qualified by these cautionary statements, and we cannot assure you that actual results or developments that we anticipate will be realized or, even if substantially realized, will have the expected consequences to or effect on us or our business or operations. For additional discussion of such risks and uncertainties, see our Annual Report on Form 10-K for the year ended December 31, 2004, and other filings we have made with the Securities and Exchange Commission ("SEC").

Critical Accounting Policies and Estimates

A summary of the significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is detailed in our consolidated financial statements for the year ended December 31, 2004, included in our Annual Report on Form 10-K. Certain of these accounting policies require the use of estimates. The following estimates, in our opinion, are subjective in nature, require the exercise of judgment and

involve complex analysis: revenue and expense accruals, including accruals for power costs, property taxes and crude oil margins; environmental costs; asset impairment analysis related to property, plant and equipment; and amortization expense and asset impairment analysis related to goodwill and other intangible assets. These estimates are based on our knowledge and understanding of current conditions and actions we may take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial condition and results of operations.

Management Overview of the Three Months and Nine Months Ended September 30, 2005

We reported net income of $30.9 million, or $0.31 per Limited Partner Unit ("Unit" or "Units"), for the three months ended September 30, 2005, compared with net income of $25.9 million, or $0.29 per Unit, for the three months ended September 30, 2004. Net income was $121.7 million, or $1.29 per

Unit, for the nine months ended September 30, 2005, compared with net income of $104.1 million, or $1.18 per Unit, for the nine months ended September 30, 2004. The weighted average number of Units outstanding was 70.0 million and 63.0 million for the three months ended September 30, 2005 and 2004, respectively, and 66.5 million and 63.0 million for the nine months ended September 30, 2005 and 2004, respectively.

Our Downstream Segment's operating income for the three months ended September 30, 2005, increased compared with the prior year period primarily due to lower depreciation expense attributable to a $4.4 million asset impairment charge in the 2004 period (see Note 3. Property, Plant and Equipment), a $4.0 million decrease in pipeline integrity costs, increased margins on product inventory sales and decreased product measurement losses. These increases to operating income were partially offset by the recognition in the 2004 period of $4.1 million of deferred revenue related to the expiration of two customer transportation agreements, $1.3 million of regulatory penalties for past incidents, the impacts of Hurricanes Katrina and Rita in the third quarter of 2005 which reduced revenues by an estimated $1.5 million, the impact of a propane release and fire at an LPG storage facility in Ohio, which reduced revenues by an estimated $0.3 million, increased pipeline operating expense, higher property taxes, higher depreciation expense primarily due to asset acquisitions and the retirement of assets in the current period, increased environmental remediation and assessment costs and transition expenses related to the change in control of our general partner.

For the nine months ended September 30, 2005, operating income for the Downstream Segment increased compared with the prior year period primarily due to a $9.7 million decrease in pipeline integrity costs, lower depreciation expense attributable to an asset impairment charge in the 2004 period, increased refined products and LPG transportation revenues and volumes and decreased product measurement losses. We anticipate that our pipeline integrity expenses for our Downstream Segment for 2005 will be approximately $15.1 million lower than our 2004 expenses primarily due to the completion of pipeline inspections and repairs under our integrity management program. These increases to operating income were partially offset by the recognition of $4.1 million of deferred revenue in the 2004 period, $1.8 million of regulatory penalties for past incidents, the impact of the hurricanes in the third quarter of 2005 and the propane release and fire at a storage facility in Ohio, increased pipeline operating expenses, higher property taxes, higher depreciation expense primarily due to asset acquisitions and the retirement of assets in the current period, transition expenses related to the change in control of our general partner and increased environmental remediation and assessment costs.

Our Upstream Segment's operating income for the three months ended September 30, 2005, increased compared with the prior year period primarily due to a $3.4 million increase in marketing margins related to asset acquisitions, lower pipeline integrity costs and increased transportation revenues on the South Texas and West Texas systems. These increases to operating income were partially offset by a $2.6 million non-cash asset impairment charge related to two of our crude oil systems and higher property taxes, depreciation expense and operating expenses related to acquisitions earlier this year (see Note 5. Acquisitions and Dispositions). For the nine months ended September 30, 2005, operating income for the Upstream Segment decreased compared with the prior year period primarily due to the non-cash impairment charge, increased operating expenses of acquired assets and higher insurance and labor expenses. These decreases to operating income were partially offset by a $4.1 million increase in transportation revenues primarily on the South Texas and West Texas systems, a $3.4 million increase in

marketing margins, lower pipeline integrity costs, lower product measurement losses and lower environmental remediation and assessment costs. Pipeline integrity expenses decreased $1.5 million and $1.8 million for the three months and nine months ended September 30, 2005, respectively, compared with the prior year periods. We anticipate that our 2005 pipeline integrity expenses for our Upstream Segment will be approximately $2.1 million lower than our 2004 expenses due to the completion of pipeline inspections and repairs under our integrity management program. Equity earnings from Seaway Crude Pipeline Company ("Seaway") decreased for the three months and nine months ended September 30, 2005, compared with the prior year periods primarily due to higher operating, general and administrative expenses primarily related to a pipeline release in May 2005 and a gain recognized on an inventory settlement in 2004, partially offset by increased transportation volumes in the 2005 periods.

Our Midstream Segment's operating income for the three months and nine months ended September 30, 2005, increased compared to the prior year periods primarily due to increased revenues and volumes on Jonah Gas Gathering Company ("Jonah"), resulting from our 2003 Phase III expansion and the installation of additional capacity during the fourth quarter of 2004. Revenues on Val Verde Gas Gathering Company ("Val Verde") increased due to new connections made to the system in May and December 2004, partially offset by the impact of reduced revenues related to the natural decline of coal bed methane ("CBM") production from existing wells. Additionally, our operating and gas settlement expenses decreased compared with the prior year period. Transportation revenues on the Panola and Chaparral Pipelines increased from the prior year periods. Pipeline integrity expenses decreased $0.7 million for the nine months ended September 30, 2005, compared with the prior year period. These increases to operating income were partially offset by lower gathering rates on the new connections at Val Verde, on which the gathering rates are lower than existing average rates on the system.

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

We believe that our current strategy and focus will provide continued growth in earnings and cash distributions. This growth potential is based on:

- Continued strong performance in our Upstream Segment, as we build on our existing asset base and concentrate on acquisitions in our core operating areas;
- Continued development of the Jonah system, which serves the Jonah and Pinedale fields;
- Gathering of volumes from infill drilling of CBM by producers and new connections of conventional gas in the San Juan Basin, where our Val Verde system is located; and
- Growth in our Downstream Segment, resulting from our recent capacity expansion, grass roots facility investments, acquisitions and growing demand for Gulf Coast sourced products.

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 are integrating 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.

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. The storage and terminaling assets will complement our existing infrastructure in Cushing and strengthen our gathering and marketing business in our Upstream Segment.

On July 12, 2005, we purchased a refined products terminal and two-bay truck loading rack in North Little Rock, Arkansas, for $6.8 million from Exxon Mobil Corporation. The assets include three storage tanks and a two-bay truck loading rack. The terminal serves the central Arkansas refined products market and complements our existing Downstream Segment infrastructure in North Little Rock, Arkansas.

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. This acquisition was made as part of an expansion of our refined products origin capabilities in the Houston, Texas, and Texas City, Texas, areas. The assets of the purchased companies will be integrated into our Downstream Segment origin infrastructure in Texas City and Baytown, Texas. 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 the Texas Gulf Coast refining and logistics system.

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

Our Business

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." TEPPCO GP, Inc. ("TEPPCO GP"), our wholly owned subsidiary, is the general partner of our Operating Partnerships. We hold a 99.999% limited partner interest in the Operating Partnerships, and TEPPCO GP holds a 0.001% general partner interest. 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. 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. Through February 23, 2005, 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.

EPCO performs all management 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 will continue to provide some administrative services for us for a period of time until we assume 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.

In connection with our formation in 1990, the Company received 2,500,000 Deferred Participation Interests ("DPIs"). Effective April 1, 1994, the DPIs began participating in distributions of cash and allocations of profit and loss in a manner identical to Limited Partner Units and are treated as Limited Partner Units for purposes of this Report. These DPIs 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 DPIs for approximately $100.0 million.

We operate and report in three business segments:

- Downstream Segment — transportation and storage of refined products, liquefied petroleum gases ("LPGs") and petrochemicals;

- Upstream Segment — gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals; and

- Midstream Segment — gathering of natural gas, transportation of natural gas liquids ("NGLs") and fractionation of NGLs.

Our reportable segments offer different products and services and are managed separately because each requires different business strategies. TEPPCO GP, our wholly owned subsidiary, acts as managing general partner of our Operating Partnerships, with a 0.001% general partner interest and manages our subsidiaries.

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 in the Northeast 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 Pipeline LLC ("Centennial") and Mont Belvieu Storage Partners, L.P. ("MB Storage") (see Note 7. Equity Investments).

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale of the crude oil to local refineries, marketers or other end users. Our Upstream Segment also includes our equity investment in Seaway (see Note 7. Equity Investments). Seaway consists of large diameter pipelines that transport crude oil from Seaway's marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

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

Results of Operations

The following table summarizes financial information by business segment for the three months and nine months ended September 30, 2005 and 2004 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Operating revenues:				
Downstream Segment	$ 66,094	$ 68,546	$ 207,699	$ 205,719
Upstream Segment	2,380,734	1,370,086	5,750,514	3,807,436
Midstream Segment	57,310	51,695	164,959	151,862
Intersegment eliminations	(342)	(317)	(2,391)	(2,382)
Total operating revenues	2,503,796	1,490,010	6,120,781	4,162,635
Operating income:				
Downstream Segment	14,615	12,781	61,099	53,082
Upstream Segment	5,207	4,778	22,199	23,314
Midstream Segment	24,248	19,522	77,791	56,987
Total operating income	44,070	37,081	161,089	133,383
Earnings before interest:				
Downstream Segment	15,445	12,662	62,249	51,661
Upstream Segment	10,881	10,781	42,160	48,494
Midstream Segment	24,323	19,543	77,968	57,082
Total earnings before interest	50,649	42,986	182,377	157,237
Interest expense	(22,033)	(18,495)	(65,202)	(57,002)
Interest capitalized	2,307	1,364	4,562	3,812
Net income	$ 30,923	$ 25,855	$ 121,737	$ 104,047

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

Downstream Segment

The following table provides financial information for the Downstream Segment for the three months and nine months ended September 30, 2005 and 2004 (in thousands):

	Three Months Ended September 30,		Increase (Decrease)	Nine Months Ended September 30,		Increase (Decrease)
	2005	2004		2005	2004	
Transportation—Refined products	$ 38,240	$ 43,386	$ (5,146)	$ 111,039	$ 113,294	$ (2,255)
Transportation—LPGs	16,519	16,071	448	63,220	58,572	4,648
Other	11,335	9,089	2,246	33,440	33,853	(413)
Total operating revenues	66,094	68,546	(2,452)	207,699	205,719	1,980
Operating, general and administrative	30,219	32,905	(2,686)	85,115	90,924	(5,809)
Operating fuel and power	8,170	8,533	(363)	23,787	23,776	11
Depreciation and amortization	10,098	12,818	(2,720)	29,460	31,106	(1,646)
Taxes—other than income taxes	3,016	1,981	1,035	8,369	7,320	1,049
Gains on sales of assets	(24)	(472)	448	(131)	(489)	358
Total costs and expenses	51,479	55,765	(4,286)	146,600	152,637	(6,037)
Operating income	14,615	12,781	1,834	61,099	53,082	8,017

Equity earnings (losses)	524	(322)	846	574	(2,069)	2,643
Other income—net	306	203	103	576	648	(72)
Earnings before interest	$ 15,445	$ 12,662	$ 2,783	$ 62,249	$ 51,661	$ 10,588

The following table presents volumes delivered in barrels and average tariff per barrel for the three months and nine months ended September 30, 2005 and 2004 (in thousands, except tariff information):

	Three Months Ended September 30,		Percentage Increase (Decrease)	Nine Months Ended September 30,		Percentage Increase (Decrease)
	2005	2004		2005	2004	
Volumes Delivered:						
Refined products	43,067	41,726	3%	123,759	116,184	7%
LPGs	8,646	9,107	(5)%	31,303	31,109	1%
Total	51,713	50,833	2%	155,062	147,293	5%
Average Tariff per Barrel:						
Refined products (1)	$ 0.89	$ 1.04	(14)%	$ 0.90	$ 0.98	(8)%
LPGs	1.91	1.76	9%	2.02	1.88	7%
Average system tariff per barrel	$ 1.06	$ 1.17	(9)%	$ 1.12	$ 1.17	(4)%

(1) The 2004 periods include $4.1 million of deferred revenue related to the expiration of two customer transportation agreements.

Three Months Ended September 30, 2005 Compared with Three Months Ended September 30, 2004

Revenues from refined products transportation decreased $5.1 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, primarily due to the recognition in the 2004 period of $4.1 million of deferred revenue related to the expiration of two customer transportation agreements. The $4.1 million of deferred revenue increased the refined products average tariff for the third quarter of 2004 by $0.10 per barrel, or 11%. Excluding the effect of the deferred revenue recognized in the 2004 period, the refined products average tariff per barrel decreased 5% from the prior year period primarily due to the impact of

greater growth in the volume of products delivered under a Centennial tariff compared with the growth in deliveries under a TEPPCO tariff, which resulted in an increased proportion of lower tariff barrels transported on our system. Prior to the construction of Centennial, deliveries on our pipeline system were limited by our pipeline capacity, and transportation services for our customers were allocated in accordance with a proration policy. With this incremental pipeline capacity, our previously constrained system has expanded deliveries in markets both south and north of Creal Springs, Illinois. In February 2003, we entered into a lease agreement with Centennial that increased our flexibility to deliver refined products to our market areas. Centennial has provided our system with additional pipeline capacity for movement of products originating in the U.S. Gulf Coast area. The overall increase in refined products volumes was primarily due to increased demand and market share for products supplied from the U.S. Gulf Coast into Midwest markets.

Revenues from LPGs transportation increased $0.4 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, due to higher deliveries of isobutane in the upper Midwest market areas, partially offset by lower deliveries of propane. The LPGs average rate per barrel increased from the prior period primarily as a result of decreased short-haul deliveries during the three months ended September 30, 2005, and an increase in tariff rates which went into effect in July 2005. Our propane revenues also decreased due to a propane release and fire at a dehydration unit in September 2005 at our Todhunter storage facility, near Middletown, Ohio. As a result of the propane release and fire, our LPG loading facilities at Todhunter were shut down for approximately three weeks. We estimate that the reduction to propane revenues for this occurrence was approximately $0.3 million for the third quarter of 2005. The propane release and fire will also reduce fourth quarter 2005 propane revenues by an estimated $0.3 million.

Revenues from refined products and LPGs for the current period were also impacted by Hurricane Katrina and Hurricane Rita, which affected the U.S. Gulf Coast in August and September 2005, respectively. Hurricane Katrina disrupted refineries and other pipeline systems in the central U.S. Gulf Coast, which provided us with additional deliveries at Shreveport and Arcadia, Louisiana, as shippers used alternative sources to supply product to areas where normal distribution patterns were disrupted. Hurricane Katrina also resulted in higher prices of refined products and LPGs, which had a negative impact on the current demand for the products.

Hurricane Rita disrupted production at western U.S. Gulf Coast refineries, many of which directly supply us with product. Hurricane Rita also disrupted power to our Beaumont terminal, which resulted in the mainline being shut down for four days and Centennial being shut down for ten days. Our mainline system was reopened, but has been operating at reduced rates as a result of Hurricane Rita. At September 30, 2005, our 230,000 barrel per day capacity, 20-inch diameter mainline system, which primarily delivers LPGs and gasoline from the Texas Gulf Coast to the Midwest, was pumping from MB Storage’s facility at approximately 60% of normal operating capacity. Our 110,000 barrel per day capacity, 14-inch and 16-inch diameter pipelines, which primarily deliver distillates and gasoline from the Texas Gulf Coast to the Midwest, were pumping at approximately 75% of normal operating capacity from our Baytown, Texas, terminal. We installed generators at our Beaumont, Texas, facility, which enabled receipt and delivery of refined products out of tankage at the terminal. Commercial power was restored to the Beaumont terminal and the Newton, Texas, pump station in mid-October and full operations were resumed. Centennial resumed operating at its normal capacity on October 1, 2005. For the quarter ended September 30, 2005, we estimate that the hurricanes reduced refined products and propane revenues by approximately $1.2 million and $0.3 million, respectively. The impact to operating expenses for the period was less than $0.1 million through September 30, 2005. We expect the impact of Hurricane Rita to reduce our fourth quarter 2005 revenues as well, resulting in estimated losses in that period of approximately $4.0 million of refined products revenues and $0.5 million of LPG revenues. The estimated impact to operating expenses for the fourth quarter of 2005 is an increase of approximately $1.2 million.

Other operating revenues increased $2.2 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, primarily due to increased margins on product inventory sales and higher refined products additive and tender deduction revenue.

Costs and expenses decreased $4.3 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, due to decreased operating, general and administrative expenses, decreased depreciation and amortization expense and decreased operating fuel and power, partially offset by increased taxes — other than income taxes and lower gains on the sales of assets in the 2005 period. Operating, general and administrative expenses decreased $2.7 million primarily due to a $4.0 million decrease in pipeline inspection and repair costs associated with our integrity management program, a $0.6 million decrease in product losses, a $0.6 million decrease in labor and benefits expenses related to the vesting of certain of our compensation plans in the first quarter of 2005 as a result of changes in control of our General Partner, a $0.6 million decrease in rental expense from the Centennial pipeline capacity lease agreement and a $0.5 million decrease in rental expense on a lease agreement with a third-party pipeline.

These decreases to costs and expenses were partially offset by a $1.3 million increase attributable to regulatory penalties for past incidents, a $0.7 million increase in pipeline operating and maintenance expenses, a $0.4 million increase in labor and benefits expense related to retirement plan settlements with DEFS, a $0.4 million increase related to transition costs due to the changes in control of our General Partner, a $0.4 million increase in environmental assessment and remediation expenses and an increase in insurance expense. Depreciation expense increased $2.7 million primarily due to a $0.8 million write-off of assets related to the propane release and fire at a storage facility in Ohio and assets retired to depreciation expense during the quarter, partially offset by a $4.4 million non-cash impairment charge in the third quarter of 2004 (see Note 3. Property, Plant and Equipment). Operating fuel and power decreased $0.4 million primarily due to adjustments to power accruals, partially offset by increased mainline throughput. Taxes — other than income taxes increased $1.0 million primarily due to increases in property tax accruals and a higher asset base in the 2005 period. During the three months ended September 30, 2004, we recognized net gains of $0.5 million from the sales of various assets in the Downstream Segment.

Net earnings from equity investments increased for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, as shown below (in thousands):

	Three Months Ended September 30,		
	2005	2004	Increase
Centennial	$ (1,216)	$ (1,839)	$ 623
MB Storage	1,728	1,530	198
Other	12	(13)	25
Total equity earnings (losses)	$ 524	$ (322)	$ 846

Equity losses in Centennial decreased $0.6 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, primarily due to higher transportation revenues, decreased operating expenses and lower product measurement losses during the 2005 period. Equity earnings in MB Storage increased $0.2 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, primarily due to increased tender deduction and lease line revenues on the MB Storage system. As a result of Hurricane Rita, MB Storage's revenues were reduced by approximately $0.2 million during the three months ended September 30, 2005. We expect the impact of Hurricane Rita to reduce MB Storage's fourth quarter 2005 revenues by an estimated $0.1 million and increase operating expenses by an estimated $0.4 million.

Nine Months Ended September 30, 2005 Compared with Nine Months Ended September 30, 2004

Revenues from refined products transportation decreased $2.3 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, primarily due to the recognition of $4.1 million of deferred revenue in the 2004 period related to the expiration of two customer transportation agreements, and the effects of Hurricanes Katrina and Rita in August and September 2005 as discussed above, partially offset by an overall increase in the refined products volumes delivered. This increase was primarily due to deliveries of products moved on Centennial. Volume increases were due to increased demand and market share for products

supplied from the U.S. Gulf Coast into Midwest markets. The refined products average rate per barrel decreased from the prior year period primarily due to the impact of greater growth in the volume of products delivered under a Centennial tariff compared with the growth in deliveries under a TEPPCO tariff, which resulted in an increased proportion of lower tariff barrels transported on our system.

Revenues from LPGs transportation increased $4.7 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, due to higher deliveries of propane in the upper Midwest and Northeast market areas primarily resulting from cold weather in March 2005. Prior year LPG transportation revenues were negatively impacted by a price spike in the Mont Belvieu propane price in late February 2004, which resulted in TEPPCO sourced propane being less competitive than propane from other source points. Our propane revenues were also affected by Hurricane Rita and the propane release and fire at a storage facility in September 2005 as discussed above.

Other operating revenues decreased $0.4 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, primarily due to lower propane inventory fees in the 2005 period, partially offset by higher refined products tender deduction and loading revenues and increased margins on product inventory sales.

Costs and expenses decreased $6.0 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, due to decreased operating, general and administrative expenses and decreased depreciation and amortization expense, partially offset by increased taxes — other than income taxes and lower gains on the sales of assets in the 2005 period. Operating, general and administrative expenses decreased $5.8 million primarily due to a $9.7 million decrease in pipeline inspection and repair costs associated with our integrity management program, a $2.0 million decrease in postretirement benefit accruals related to plan amendments (see Note 10. Employee Benefit Plans), a $1.1 million decrease in consulting services primarily related to acquisition related activities in the 2004 period and a $0.7 million decrease in product losses.

These decreases to costs and expenses were partially offset by a $1.8 million increase in labor and benefits expenses associated with vesting provisions in certain of our compensation plans as a result of changes in control of our General Partner resulting in higher incentive compensation expenses compared to the prior year period, a $1.8 million increase attributable to regulatory penalties for past incidents, a $1.4 million increase in pipeline operating and maintenance expense, a $0.6 million increase related to transition costs due to the changes in control of our General Partner, a $0.4 million increase in environmental assessment and remediation expenses, a $0.4 million increase in labor and benefits expense related to retirement plan settlements with DEFS and an increase in insurance expense. Depreciation expense decreased $1.6 million primarily due to a $4.4 million non-cash impairment charge in the third quarter of 2004, partially offset by a $0.8 million write-off of assets related to the propane release and fire at a storage facility in Ohio (see Note 3. Property Plant, and Equipment), assets placed into service and assets retired to depreciation expense in the 2005 period. Taxes — other than income taxes increased $1.0 million primarily due to asset acquisitions and a higher tax base in the 2005 period. During the nine months ended September 30, 2004, we recognized net gains of $0.5 million from the sales of various assets in the Downstream Segment.

Net earnings from equity investments increased for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, as shown below (in thousands):

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Increase (Decrease)
Centennial	$ (5,184)	$ (7,982)	$ 2,798
MB Storage	5,727	5,944	(217)
Other	31	(31)	62
Total equity earnings (losses)	$ 574	$ (2,069)	$ 2,643

Equity losses in Centennial decreased $2.8 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, primarily due to higher transportation revenues and volumes and lower transmix related product replacement costs and product measurement losses during the 2005 period. Equity earnings in MB Storage decreased $0.2 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, primarily due to increased depreciation and amortization expense and higher general and administrative expenses, partially offset by higher rental and storage revenues and volumes. MB Storage's revenues were also impacted by Hurricane Rita as discussed above. In April 2004, MB Storage acquired storage and pipeline assets and contracts for approximately $35.0 million, of which TE Products contributed $16.5 million. Increases in storage revenue, shuttle revenue, rental revenue and depreciation and amortization expense for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, are primarily related to the acquired storage assets and contracts.

Upstream Segment

The following table provides financial information for the Upstream Segment for the three months and nine months ended September 30, 2005 and 2004 (in thousands):

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Increase (Decrease)	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Increase (Decrease)
Sales of petroleum products	$ 2,367,984	$ 1,358,220	$ 1,009,764	$ 5,714,353	$ 3,770,006	$ 1,944,347
Transportation—Crude oil	10,001	9,288	713	28,215	28,164	51
Other	2,749	2,578	171	7,946	9,266	(1,320)
Total operating revenues	2,380,734	1,370,086	1,010,648	5,750,514	3,807,436	1,943,078
Purchases of petroleum products	2,350,107	1,344,613	1,005,494	5,665,136	3,728,345	1,936,791
Operating, general and administrative	15,972	15,412	560	41,700	39,279	2,421
Operating fuel and power	1,247	1,240	7	3,709	4,373	(664)
Depreciation and amortization	6,471	3,268	3,203	13,623	9,381	4,242
Taxes—other than income taxes	1,737	1,152	585	4,206	3,228	978
Gains on sales of assets	(7)	(377)	370	(59)	(484)	425
Total costs and expenses	2,375,527	1,365,308	1,010,219	5,728,315	3,784,122	1,944,193
Operating income	5,207	4,778	429	22,199	23,314	(1,115)
Equity earnings	5,571	5,943	(372)	19,829	24,923	(5,094)
Other income—net	103	60	43	132	257	(125)
Earnings before interest	$ 10,881	$ 10,781	$ 100	$ 42,160	$ 48,494	$ (6,334)

Information presented in the following table includes the margin of the Upstream Segment, which may be viewed as a non-GAAP (Generally Accepted Accounting Principles) financial measure under the rules of the SEC. We calculate the margin of the Upstream Segment as revenues generated from the sale of crude oil and lubrication oil, and transportation of crude oil, less the costs of purchases of crude oil and lubrication oil. We believe that margin is a more meaningful measure of financial performance than sales and purchases of crude oil and lubrication oil due to the significant fluctuations in sales and purchases caused by variations in the level of volumes marketed and prices for products marketed. Additionally, we use margin internally to evaluate the financial performance of the Upstream Segment as we believe margin is a better indicator of performance than operating income as operating, general and administrative expenses, operating fuel and power and depreciation expense are not directly related to the margin activities. Margin and volume information for the three months and nine months ended September 30, 2005 and 2004 is presented below (in thousands, except per barrel and per gallon amounts):

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Percentage Increase (Decrease)	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Percentage Increase (Decrease)
Margins: (1)						
Crude oil transportation	$ 15,626	$ 14,485	8%	$ 44,982	$ 40,860	10%
Crude oil marketing	7,750	4,327	79%	20,282	16,920	20%
Crude oil terminaling	2,552	2,426	5%	6,785	7,392	(8)%
Lubrication oil sales	1,950	1,657	18%	5,383	4,653	16%
Total margin	$ 27,878	$ 22,895	22%	$ 77,432	$ 69,825	11%
Total barrels:						
Crude oil transportation	23,659	25,093	(6)%	71,181	75,941	(6)%
Crude oil marketing	54,747	43,284	26%	147,905	131,208	13%
Crude oil terminaling	28,528	28,889	(1)%	76,934	89,777	(14)%
Lubrication oil volume (total gallons)	3,573	3,346	7%	10,898	9,765	12%
Margin per barrel:						
Crude oil transportation	$ 0.660	$ 0.577	14%	$ 0.632	$ 0.538	17%
Crude oil marketing	0.142	0.100	42%	0.137	0.129	6%
Crude oil terminaling	0.089	0.084	7%	0.088	0.082	7%
Lubrication oil margin (per gallon)	0.546	0.495	10%	0.494	0.476	4%

(1) Margins in this table are presented prior to the elimination of intercompany sales, revenues and purchases between TEPPCO Crude Oil, L.P. and TEPPCO Crude Pipeline, L.P.

The following table reconciles the Upstream Segment margin to the consolidated statements of income using the information presented in the consolidated statements of income and the statements of income in Note 11. Segment Information (in thousands):

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Sales of petroleum products	$ 2,367,984	$ 1,358,220	$ 5,714,353	$ 3,770,006
Transportation — Crude oil	10,001	9,288	28,215	28,164
Less: Purchases of petroleum products	(2,350,107)	(1,344,613)	(5,665,136)	(3,728,345)
Total margin	27,878	22,895	77,432	69,825
Other operating revenues	2,749	2,578	7,946	9,266
Net operating revenues	30,627	25,473	85,378	79,091
Operating, general and administrative	15,972	15,412	41,700	39,279
Operating fuel and power	1,247	1,240	3,709	4,373
Depreciation and amortization	6,471	3,268	13,623	9,381
Taxes—other than income taxes	1,737	1,152	4,206	3,228
Gains on sales of assets	(7)	(377)	(59)	(484)
Operating income	$ 5,207	$ 4,778	$ 22,199	$ 23,314

Three Months Ended September 30, 2005 Compared with Three Months Ended September 30, 2004

Our margin increased $5.0 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004. Crude oil marketing margin increased $3.4 million primarily due to an increase in volumes marketed primarily due to asset acquisitions, partially offset by unrealized losses of $1.2 million related

to marking crude oil grade and location swap contracts to current market value and increased transportation costs. Crude oil transportation margin increased $1.2 million primarily due to increased transportation volumes and revenues on our South Texas and West Texas systems, partially offset by decreased transportation volumes on our Red River and Basin systems. Lubrication oil sales margin increased $0.3 million due to increased sales of chemical volumes and the acquisitions of lubrication oil distributors in Casper, Wyoming, in August 2004, and in Dumas, Texas, in July 2005. Crude oil terminaling margin increased $0.1 million as a result of an increase in pumpover volumes at Cushing, Oklahoma, partially offset by a decrease in pumpover volumes at Midland, Texas.

Other operating revenues increased $0.2 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, primarily due increased revenues from documentation and other services to support customers' trading activity at Midland and Cushing.

Costs and expenses, excluding expenses associated with purchases of crude oil and lubrication oil, increased $4.8 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, primarily due to increased depreciation and amortization expense, increased operating, general and administrative expenses, increased taxes — other than income taxes and lower gains on sales of assets in the 2005 period. Depreciation and amortization expense increased $3.2 million as a result of a $2.6 million non-cash impairment charge in the third quarter of 2005, resulting from the impairment of two crude oil systems (see Note 3. Property, Plant and Equipment). Depreciation expense also increased as a result of assets placed into service in the 2005 period related to acquisitions and assets retired to depreciation expense during the period. Operating, general and administrative expenses increased $0.6 million from the prior year period primarily due to a $1.1 million increase in pipeline operating and maintenance expense, a $0.4 million increase in insurance expense, a $0.3 million increase in labor and benefits expense relating to plan amendments (see Note 10. Employee Benefit Plans) and a $0.2 million increase in transition expenses related to changes in control of our General Partner. These increases were partially offset by a $1.5 million decrease in pipeline inspection and repair costs associated with our integrity management program and a $0.2 million decrease in labor and benefits expense related to the vesting of certain of our compensation plans in the first quarter of 2005 as a result of changes in control of our General Partner. Taxes — other than income taxes increased $0.6 million primarily as a result of a higher asset base in the 2005 period primarily due to acquisitions of assets. During the three months ended September 30, 2004, we recognized a gain of $0.4 million from the sale of our remaining interest in the original Rancho Pipeline system (see Note 5. Acquisitions and Dispositions).

Equity earnings from our investment in Seaway decreased $0.4 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, primarily due to higher operating, general and administrative expenses related to a pipeline release in May 2005 and decreased gains on inventory sales, partially offset by increased long-haul transportation volumes.

After Seaway's pipeline release in May 2005, the maximum operating pressure on the pipeline system was reduced by 20% until the cause of the failure is determined and any required corrective measures are implemented. A study of the failed pipe was performed by independent, metallurgical experts who determined that the pipe failed due to damage that occurred during rail shipment associated with its installation thirty years ago. The corrective actions include running a very sophisticated, high definition inspection tool through the pipe to determine if there are any other sections of pipe that have similar damage. This approach is consistent with directives from the United States Department of Transportation's Office of Pipeline Safety in past failures of this type. We are in the initial stages of evaluating approximately 300 miles of Seaway's pipeline that have similar vintage pipe. Because of the complexity of the inspection tool being used, we expect that it will take several months to complete the analysis of the data, as well as complete any additional repairs that are identified from the analysis. Based on these projections, we expect Seaway to be operating at reduced maximum pressures through the first quarter of 2006. As a result of operating at reduced maximum pressures, during the third quarter of 2005, we began using a drag reducing agent to increase the flow of product through the pipeline system. The drag reducing agent allowed us to maintain the higher volumes transported, but also increased our operating costs. At this time, we do not believe the reduced pressures will have a material adverse effect on our financial position, results of operations or cash flows.

Nine Months Ended September 30, 2005 Compared with Nine Months Ended September 30, 2004

Our margin increased $7.6 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004. Crude oil transportation margin increased $4.1 million primarily due to increased transportation volumes and revenues on our South Texas system and higher revenues on our Basin and West Texas systems related to movements on higher tariff segments, partially offset by decreases in transportation volumes on our Red River system and on lower tariff segments of our Basin system. Crude oil marketing margin increased $3.4 million primarily due to increased volumes marketed as a result of asset acquisitions, partially offset by increased transportation costs and unrealized losses of $0.4 million related to marking crude oil grade and location swap contracts to current market value. Lubrication oil sales margin increased $0.7 million due to increased sales of chemical volumes and the acquisitions of lubrication oil distributors in Casper, Wyoming, in August 2004, and in Dumas, Texas, in July 2005. Crude oil terminaling margin decreased $0.6 million as a result of a decrease in pumpover volumes at Midland, Texas, and Cushing, Oklahoma.

Other operating revenues decreased $1.3 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, primarily due to a $1.4 million favorable settlement of inventory imbalances in the first quarter of 2004 and lower revenues from documentation and other services to support customers' trading activity at Midland and Cushing in the first nine months of 2005.

Costs and expenses, excluding expenses associated with purchases of crude oil and lubrication oil, increased $7.4 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, due to increased depreciation and amortization expense, increased operating, general and administrative expenses, increased taxes — other than income taxes and lower gains on sales of assets in the 2005 period, partially offset by decreased operating fuel and power. Depreciation and amortization expense increased $4.4 million primarily as a result of a $2.6 million non-cash impairment charge (see Note 3. Property, Plant and Equipment). Depreciation expense also increased as a result of assets placed in service and assets retired to depreciation expense during the period. Operating, general and administrative expenses increased $2.4 million from the prior year period. This increase was primarily due to a $2.6 million increase in pipeline operating and maintenance expense, a $2.4 million increase in labor and benefits expense related to vesting provisions in certain of our compensation plans as a result of changes in control of our General Partner and an increase in the number of employees between periods and a $0.7 million increase in insurance expense. These increases were partially offset by a $0.6 million decrease in postretirement benefit accruals related to plan amendments (see Note 10. Employee Benefit Plans), a $1.8 million decrease in pipeline inspection and repair costs associated with our integrity management program, a $1.4 million decrease in environmental assessment and remediation costs and a $1.4 million decrease in product measurement losses. Taxes — other than income taxes increased $1.0 million due to increases in property tax accruals and a higher asset base in the 2005 period. During the nine months ended September 30, 2004, we recognized a gain of $0.4 million from the sale of our remaining interest in the original Rancho Pipeline system (see Note 5. Acquisitions and Dispositions). Operating fuel and power decreased $0.7 million primarily as a result of lower transportation volumes in the 2005 period.

Equity earnings from our investment in Seaway decreased $5.1 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, primarily due to higher operating, general and administrative expenses related to a pipeline release in May 2005 as discussed above, decreased gains on inventory sales, higher depreciation expense and a favorable settlement in the first quarter of 2004 with a former owner of Seaway's crude oil assets regarding inventory imbalances that were not acquired by us, partially offset by higher long-haul transportation volumes.

Midstream Segment

The following table provides financial information for the Midstream Segment for the three months and nine months ended September 30, 2005 and 2004 (in thousands):

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Increase (Decrease)	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Increase (Decrease)
Sales of petroleum products	$ 2,880	$ 1,734	$ 1,146	$ 7,337	$ 4,868	$ 2,469
Gathering—Natural Gas	38,833	35,515	3,318	112,349	104,444	7,905
Transportation—NGLs	11,829	10,430	1,399	33,435	31,022	2,413
Other	3,768	4,016	(248)	11,838	11,528	310
Total operating revenues	57,310	51,695	5,615	164,959	151,862	13,097
Purchases of petroleum products	2,623	1,381	1,242	5,799	4,367	1,432
Operating, general and administrative	11,726	12,175	(449)	31,099	34,732	(3,633)
Operating fuel and power	3,121	3,691	(570)	7,658	8,310	(652)
Depreciation and amortization	14,391	14,191	200	39,932	44,021	(4,089)
Taxes—other than income taxes	1,201	735	466	3,087	3,445	(358)
Gains on sales of assets	—	—	—	(407)	—	(407)
Total costs and expenses	33,062	32,173	889	87,168	94,875	(7,707)
Operating income	24,248	19,522	4,726	77,791	56,987	20,804
Other income—net	75	21	54	177	95	82
Earnings before interest	$ 24,323	$ 19,543	$ 4,780	$ 77,968	$ 57,082	$ 20,886

The following table presents volume and average rate information for the three months and nine months ended September 30, 2005 and 2004:

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Percentage Increase (Decrease)	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Percentage Increase (Decrease)
Gathering—Natural Gas—Jonah:						
Million cubic feet ("MMcf")	105,993	90,005	18%	302,388	257,402	17%
Billion British thermal units ("MMmbtu")	117,006	99,531	18%	333,823	284,858	17%
Average fee per Million British thermal unit ("MMBtu")	$ 0.185	$ 0.191	(4)%	$ 0.187	$ 0.195	(4)%
Gathering—Natural Gas—Val Verde:						
MMcf	46,273	36,733	26%	131,646	108,213	22%
MMmbtu	40,881	31,294	31%	115,685	91,459	26%
Average fee per MMBtu	$ 0.422	$ 0.527	(20)%	$ 0.430	$ 0.533	(19)%
Transportation—NGLs:						
Thousand barrels	16,332	15,064	8%	45,708	45,209	1%
Average rate per barrel	$ 0.724	$ 0.692	5%	$ 0.731	$ 0.686	7%
Fractionation—NGLs:						
Thousand barrels	1,068	994	7%	3,294	3,064	7%
Average rate per barrel	$ 1.768	$ 1.866	(6)%	$ 1.744	$ 1.802	(3)%
Sales—Condensate:						
Thousand barrels	3.4	7.3	(54)%	44.6	67.0	(33)%
Average rate per barrel	$ 55.60	$ 43.54	28%	$ 50.21	$ 35.58	41%

The following table reconciles the Midstream Segment margin to operating income in the consolidated statements of income using the information presented in the tables above, in the consolidated statements of income and in the statements of income in Note 11. Segment Information (in thousands):

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Sales of petroleum products	$ 2,880	$ 1,734	$ 7,337	$ 4,868
Less: Purchases of petroleum products	(2,623)	(1,381)	(5,799)	(4,367)
Total margin	257	353	1,538	501
Gathering—Natural Gas	38,833	35,515	112,349	104,444
Transportation—NGLs	11,829	10,430	33,435	31,022
Other operating revenues	3,768	4,016	11,838	11,528
Net operating revenues	54,687	50,314	159,160	147,495

Operating, general and administrative	11,726	12,175	31,099	34,732
Operating fuel and power	3,121	3,691	7,658	8,310
Depreciation and amortization	14,391	14,191	39,932	44,021
Taxes—other than income taxes	1,201	735	3,087	3,445
Gains on sales of assets	—	—	(407)	—
Operating income	$ 24,248	$ 19,522	$ 77,791	$ 56,987

Three Months Ended September 30, 2005 Compared with Three Months Ended September 30, 2004

Revenues from the gathering of natural gas increased $3.3 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004. Natural gas gathering revenues from the Jonah system increased $2.5 million and volumes gathered increased 16.0 billion cubic feet ("Bcf") for the three months ended September 30, 2005, primarily due to the expansion of the Jonah system in 2004. Installation of additional capacity of 100 million cubic feet per day was completed during the fourth quarter of 2004. Jonah's average natural gas gathering rate per MMcf decreased due to higher system wellhead pressures. Natural gas gathering revenues from the Val Verde system increased $0.8 million and volumes gathered increased 7.0 Bcf for the three months ended September 30, 2005, primarily due to increased volumes from two new connections made to the Val Verde system in May and December 2004, partially offset by the natural decline of CBM production, slower than anticipated completion and connection of infill wells and less volume from infill wells than was anticipated. Val Verde's average natural gas gathering rate per MMcf decreased due to contracts entered into relating to the new connections, which have lower rates than the existing Val Verde system's average rates.

Revenues from the transportation of NGLs increased $1.4 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, primarily due to increases in volumes transported on the Panola and Chaparral Pipelines, partially offset by decreases in volumes transported on the Dean and Wilcox Pipelines. The increase in the NGL transportation average rate per barrel resulted from higher average rates per barrel on volumes transported on the Panola and Chaparral Pipelines.

Other operating revenues decreased $0.3 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004. The decrease was due to various miscellaneous revenue items.

Costs and expenses (excluding purchases of petroleum products) decreased $0.4 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, due to decreases in operating, general and administrative expenses and operating fuel and power, partially offset by increases in taxes — other than income taxes and depreciation and amortization expense. Operating, general and administrative expenses decreased $0.5 million primarily due to a $1.3 million decrease in gas settlement expenses and a decrease in consulting and contract services related to compliance with the Sarbanes-Oxley Act of 2002, partially offset by a

$0.9 million increase in labor and benefits expenses associated with certain of our compensation plans and a $0.4 million increase in transition expenses as a result of changes in control of our General Partner. Operating fuel and power decreased $0.6 million compared to the prior year period due to adjustments to the fuel and power accrual in the prior year period, partially offset by increased expenses in the 2005 period related to higher transportation volumes. Taxes — other than income taxes increased $0.5 million as a result of adjustments to property tax accruals primarily related to the expansion of the Jonah system. Depreciation expense increased $0.4 million primarily due to a $0.4 million increase on Val Verde as a result of assets placed into service in 2004 and an increase on Panola due to assets retired to depreciation expense, partially offset by a $0.2 million decrease on Jonah as a result of increases to the estimated lives of Jonah's assets. Amortization expense on the Jonah system decreased $1.0 million primarily due to a $1.3 million decrease related to revisions to the estimated life of intangible assets under the units-of-production method, partially offset by a $0.3 million increase as a result of higher volumes on the Jonah system in the 2005 period. Amortization expense on the Val Verde system increased $0.8 million primarily due to at $1.3 million increase related to revisions to the estimated life of intangible assets under the units-of-production method, partially offset by a $0.5 million decrease as a result of lower volumes in the 2005 period on contracts included in the intangible assets, resulting from the natural decline in CBM production. From time to time, updated production forecasts are obtained from some of the producers on the Jonah and Val Verde systems, and as a result, we revise our best estimate of future throughput on the these systems (see Note 2. Goodwill and Other Intangible Assets).

Nine Months Ended September 30, 2005 Compared with Nine Months Ended September 30, 2004

Revenues from the gathering of natural gas increased $7.9 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004. Natural gas gathering revenues from the Jonah system increased $6.9 million and volumes gathered increased 45.0 Bcf for the nine months ended September 30, 2005, primarily due to the expansion of the Jonah system in 2004. Installation of additional capacity of 100 million cubic feet per day was completed during the fourth quarter of 2004. Jonah's average natural gas gathering rate per MMcf decreased due to higher system wellhead pressures. Natural gas gathering revenues from the Val Verde system increased $1.0 million and volumes gathered increased 23.4 Bcf for the nine months ended September 30, 2005, primarily due to increased volumes from two new connections made to the Val Verde system in May and December 2004, partially offset by the natural decline of CBM production, slower than anticipated completion and connection of infill wells and less volume from infill wells than was anticipated. Val Verde's average natural gas gathering rate per MMcf decreased due to contracts entered into relating to the new connections, which have lower rates than the existing Val Verde system's average rates.

Margin (sales of petroleum products less purchases of petroleum products) resulting from the processing arrangements at the Jonah Pioneer plant increased $1.0 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, primarily due to increased volumes and higher NGL prices. Jonah's Pioneer gas processing plant was completed during the first quarter of 2004, as a part of the Phase III expansion to increase the processing capacity in southwestern Wyoming. Pioneer's processing agreements allow the producers to elect annually whether to be charged under a fee-based arrangement or a fee plus keep-whole arrangement. Under the fee-based election, Jonah receives a fee for its processing services. Under the fee plus keep-whole election, Jonah receives a lower fee for its processing services, retains and sells the NGLs extracted during the process and delivers to producers the residue gas equivalent in energy to the natural gas received from the producers. Jonah sells the NGLs it retains and purchases gas to replace the equivalent energy removed in the liquids. For the 2004 and 2005 periods, the producers elected the fee plus keep-whole arrangement.

Revenues from the transportation of NGLs increased $2.4 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, primarily due to increases in volumes transported on the Panola and Chaparral Pipelines, partially offset by decreases in volumes transported on the Dean and Wilcox Pipelines. The increase in the NGL transportation average rate per barrel resulted from higher average rates per barrel on volumes transported on the Panola and Chaparral Pipelines.

Other operating revenues increased $0.3 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004. This increase was primarily due to a $0.2 million increase in NGL fractionation revenues as a result of higher volumes.

Costs and expenses (excluding purchases of petroleum products) decreased $9.1 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, due to decreases in depreciation and amortization expense, operating, general and administrative expenses, operating fuel and power and taxes — other than income taxes and a net gain recorded on the sale of an asset. Amortization expense on the Jonah system decreased $2.7 million primarily due to a $3.7 million decrease related to revisions to the estimated life of intangible assets under the units-of-production method, partially offset by a $1.0 million increase as a result of higher volumes in the 2005 period. Amortization expense on the Val Verde system increased $0.3 million primarily due to a $1.4 million increase related to revisions to the estimated life of intangible assets under the units-of-production method, partially offset by a $1.1 million decrease as a result of lower volumes in the 2005 period on contracts included in the intangible assets, resulting from the natural decline in CBM production. Depreciation expense decreased $1.7 million primarily due to a $3.7 million decrease on Jonah as a result of increases to the estimated lives of Jonah's assets, partially offset by a $1.7 million increase on Val Verde and a $0.3 million increase on Panola as a result of assets placed into service in 2004. Operating, general and administrative expenses decreased $3.6 million primarily due to a $4.8 million decrease in gas settlement expenses, a $0.7 million decrease in inspection and repair costs associated with our integrity management program and a decrease in consulting and contract services related to compliance with the Sarbanes-Oxley Act of 2002. These decreases were partially offset by a $2.1 million increase in labor and benefits expense primarily associated with vesting provisions in certain of our compensation plans and with certain DEFS employees becoming employees of EPCO and a $0.7 million increase in transition expenses as a result of changes in control of our General Partner. Operating fuel and power decreased $0.7 million compared to the prior year period due to adjustments to the fuel and power accrual in the prior year period, partially offset by increased expenses in the 2005 period related to higher transportation volumes. Taxes — other than income taxes decreased $0.3 million as a result of adjustments to property tax accruals. A net gain of $0.4 million was recognized on the sale of equipment in the current period.

Interest Expense and Capitalized Interest

Three Months Ended September 30, 2005 Compared with Three Months Ended September 30, 2004

Interest expense increased $3.5 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, primarily due to higher short term floating interest rates on our revolving credit facility and higher outstanding debt balances.

Capitalized interest increased $0.9 million for the three months ended September 30, 2005, compared with the three months ended September 30, 2004, due to higher construction work-in-progress balances in the 2005 period.

Nine Months Ended September 30, 2005 Compared with Nine Months Ended September 30, 2004

Interest expense increased $8.2 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, primarily due to higher outstanding borrowings and higher short term floating interest rates on our revolving credit facility and $2.0 million of expense related to the termination of a treasury lock (see Note 4. Interest Rate Swaps). These increases were partially offset by a higher percentage of fixed interest rate debt during the nine months ended September 30, 2004, that carried a higher rate of interest as compared with floating interest rate debt. The higher percentage of fixed interest rate debt resulted from an interest rate swap that expired in April 2004 (see Note 4. Interest Rate Swaps).

Capitalized interest increased $0.7 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, due to higher construction work-in-progress balances in the 2005 period.

Financial Condition and Liquidity

Cash generated from operations, credit facilities and debt and equity offerings are our primary sources of liquidity. At September 30, 2005, we had a working capital surplus of $93.5 million, while at December 31, 2004, we had a working capital deficit of $37.8 million. At September 30, 2005, we had approximately $139.5 million in available borrowing capacity under our revolving credit facility. Cash flows for the nine months ended September 30, 2005 and 2004 were as follows (in millions):

	Nine Months Ended September 30,	
	2005	2004
Cash provided by (used in):		
Operating activities	$ 44.0	$ 173.9
Investing activities	(262.4)	(134.9)
Financing activities	202.1	(58.9)

Operating Activities

Net cash from operating activities for the nine months ended September 30, 2005 and 2004, was comprised of the following (in millions):

	Nine Months Ended September 30,	
	2005	2004

Net income	$ 121.7	$ 104.1
Depreciation and amortization	83.0	84.5
Earnings in equity investments	(20.4)	(22.9)
Distributions from equity investments	28.2	39.5
Gains on sales of assets	(0.6)	(1.0)
Non-cash portion of interest expense	1.2	0.2
Cash used in working capital and other	(169.1)	(30.5)
Net cash from operating activities	$ 44.0	$ 173.9

For a discussion of changes in earnings before interest, depreciation and amortization, equity earnings, gain on sales of assets by segment and consolidated interest expense — net, see "— Results of Operations for the Downstream Segment, Upstream Segment and Midstream Segment." Cash provided by operating activities decreased $129.9 million for the nine months ended September 30, 2005, compared with the nine months ended September 30, 2004, primarily due to the timing of cash disbursements and cash receipts for crude oil inventory and other working capital components and an $11.3 million decrease in distributions received from our equity investments during the nine months ended September 30, 2005, partially offset by higher net income and lower depreciation and amortization expense in the 2005 period.

During the second and third quarters of 2005, we purchased crude oil and simultaneously entered into offsetting sales contracts for physical delivery during the fourth quarter of 2005. The purpose of these contracts was to lock in a margin on the crude oil while it is stored in our facilities. These purchases had a negative impact on cash from operating activities when the invoices for the purchase of the crude oil were paid. We utilized borrowings under our revolving credit facility to fund a large portion of the crude oil purchases. These borrowings on our revolving credit facility are shown as financing activities in the statement of cash flows. Until we deliver the crude oil in the fourth quarter of 2005 and subsequently receive payment from our customers, cash from operating activities will be negatively impacted by this activity.

Net cash from operating activities for the nine months ended September 30, 2005 and 2004, included interest payments, net of amounts capitalized, of $78.5 million and $75.5 million, respectively. Excluding the effects of hedging activities and interest capitalized during the year ended December 31, 2005, we expect interest payments on our fixed rate Senior Notes to be approximately $77.8 million. We expect to pay our interest payments with cash flows from operating activities.

Investing Activities

Cash flows used in investing activities totaled $262.4 million for the nine months ended September 30, 2005, and were comprised of $148.1 million of capital expenditures, $68.9 million for the acquisition of Downstream Segment assets, $43.3 million for the acquisition of Upstream Segment assets and $2.6 million of cash contributions for TE Products' ownership interest in MB Storage for capital expenditures, partially offset by $0.5 million in net cash proceeds from an asset sale in our Midstream Segment. Cash flows used in investing activities totaled $134.9 million for the nine months ended September 30, 2004, and were comprised of $111.0 million of capital expenditures, $1.5 million of cash contributions for TE Products' ownership interest in Centennial to cover operating needs and capital expenditures, $20.2 million of cash contributions for TE Products' ownership interest in MB Storage, of which $16.5 million was used to acquire storage assets, and $3.4 million for the acquisition of assets during the nine months ended September 30, 2004, partially offset by $1.2 million in net cash proceeds from the sales of various assets in our Upstream and Downstream Segments.

Financing Activities

Cash flows provided by financing activities totaled $202.1 million for the nine months ended September 30, 2005, and were comprised of $278.8 million of net proceeds received from the issuance of 7.0 million Units in May and June 2005 and $107.5 million in borrowings, net of repayments, on our revolving credit facility, partially offset by $184.2 million of distributions paid to unitholders. Cash flows used in financing activities totaled $58.9 million for the nine months ended September 30, 2004, and were comprised of $174.4 million of distributions paid to unitholders, partially offset by $115.5 million in borrowings, net of repayments, on our revolving credit facility.

We paid cash distributions of $184.2 million ($2.00 per Unit) and $174.4 million ($1.975 per Unit) during the nine months ended September 30, 2005 and 2004, respectively. Additionally, we declared a cash distribution of $0.675 per Unit for the quarter ended September 30, 2005. We will pay the distribution of $66.9 million on November 7, 2005, to unitholders of record on October 31, 2005.

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.

Universal Shelf

We have filed with the SEC a universal shelf registration statement that, subject to agreement on terms at the time of use and appropriate supplementation, allows us to issue, in one or more offerings, up to an aggregate of $2.0 billion of equity securities, debt securities or a combination thereof. In the May 2005 equity offering, we issued $279.2 million of equity securities. At September 30, 2005, we had $1.7 billion remaining under this shelf registration, subject to customary marketing terms and conditions.

Credit Facilities

We have in place an unsecured revolving credit facility for up to $600.0 million ("Revolving Credit Facility"), including the issuance of letters of credit of up to $100.0 million. Interest is payable at an applicable margin above either the lender's base rate or LIBOR. At September 30, 2005, $460.5 million was outstanding under the facility, and we had $139.5 million of availability. Restrictive covenants in the credit agreement limit our ability to, among other things, incur additional indebtedness, make distributions in excess of Available Cash (see Note 9. Partners' Capital and Distributions), and complete mergers, acquisitions and sales of assets. In addition, the credit agreement requires us to maintain certain financial ratios, which we were in compliance with at September 30, 2005.

Centennial entered into credit facilities totaling $150.0 million, and as of September 30, 2005, $150.0 million was outstanding under those credit facilities. TE Products and Marathon Petroleum Company LLC ("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 September 30, 2005.

2005 Capital Expenditures

We estimate that capital expenditures, excluding acquisitions, for 2005 will be approximately $239.0 million (including $7.0 million of capitalized interest). We expect to spend approximately $176.6 million for revenue generating projects and facility improvements. Capital spending on revenue generating projects and facility improvements will include approximately $17.5 million for the expansion of our Downstream Segment facilities. We expect to spend $18.8 million to expand our Upstream Segment pipelines and facilities in West Texas and Oklahoma and approximately $140.3 million to expand our Midstream Segment assets, with further expansions on our Jonah system. We expect to spend approximately $36.2 million to sustain existing operations, including life-cycle replacements for equipment at various facilities and pipeline and tank replacements among all of our business segments. We expect to spend approximately $19.2 million to improve operational efficiencies and reduce costs among all of our business segments. During the remainder of 2005, TE Products may be required to contribute cash to Centennial to cover capital expenditures, acquisitions or other operating needs and to MB Storage to cover significant capital expenditures or additional acquisitions. We continually review and evaluate potential capital improvements and expansions that would be complementary to our present business operations. These expenditures can vary greatly depending on the magnitude of our transactions.

Liquidity Outlook

We believe that we will continue to have adequate liquidity to fund future recurring operating and investing activities. Our primary cash requirements consist of normal operating expenses, capital expenditures to sustain existing operations and revenue generating expenditures, interest payments on our Senior Notes and Revolving Credit Facility, distributions to our General Partner and unitholders and acquisitions of new assets or businesses. Our cash requirements for the remainder of 2005 and 2006, such as operating expenses, capital expenditures to sustain existing operations and quarterly distributions to our General Partner and unitholders, are expected to be funded through operating cash flows. Long-term cash requirements for expansion projects, acquisitions and debt repayments are expected to be funded by several sources, including cash flows from operating activities, borrowings under credit facilities, and possibly the issuance of additional equity and debt securities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

Off-Balance Sheet Arrangements

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

Contractual Obligations

The following table summarizes our debt repayment obligations and material contractual commitments as of September 30, 2005 (in millions):

	Amount of Commitment Expiration Per Period				
	Total	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
Revolving Credit Facility	$ 460.5	$ —	$ —	$ 460.5	$ —
6.45% Senior Notes due 2008 (1) (2)	180.0	—	180.0	—	—
7.625% Senior Notes due 2012 (2)	500.0	—	—	—	500.0
6.125% Senior Notes due 2013 (2)	200.0	—	—	—	200.0
7.51% Senior Notes due 2028 (1) (2)	210.0	—	—	—	210.0
Debt subtotal	1,550.5	—	180.0	460.5	910.0
Operating leases (3)	79.7	18.9	30.2	15.1	15.5
Capital expenditure obligations (4)	24.7	24.7	—	—	—
Other liabilities and deferred credits (5)	8.5	—	3.5	1.0	4.0
Total	$ 1,663.4	$ 43.6	$ 213.7	$ 476.6	$ 929.5

(1) Obligations of TE Products.

(2) Our TE Products subsidiary entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its 7.51% Senior Notes due 2028. At September 30, 2005, the 7.51% Senior Notes include an adjustment to increase the fair value of the debt by $1.3 million related to this interest rate swap agreement. We also entered into interest rate swap agreements to hedge our exposure to changes in the fair value of our 7.625% Senior Notes due 2012. At September 30, 2005, the 7.625% Senior Notes include a deferred gain, net of amortization, from previous interest rate swap terminations of

$33.5 million. At September 30, 2005, our 6.45% Senior Notes, our 7.625% Senior Notes and our 6.125% Senior Notes include $2.5 million of unamortized debt discounts. The fair value adjustments, the deferred gain adjustment and the unamortized debt discounts are excluded from this table.

(3) Includes a pipeline capacity lease with Centennial. In January 2003, TE Products entered into a pipeline capacity lease agreement with Centennial for a period of five years that contains a minimum throughput requirement. For the year ended December 31, 2004, TE Products exceeded the minimum throughput requirements on the lease agreement.

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

(5) Excludes approximately $9.0 million of long-term deferred revenue payments, which are being transferred to income over the term of the respective revenue contracts. The amount of commitment by year is our best estimate of projected payments of these long-term liabilities.

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

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 $4.7 million obligation, which represents the present value of the estimated amount that we would have to pay under the guarantee. In the event that a catastrophic event occurred and we were required to contribute cash to Centennial, contributions exceeding our deductible may be covered by our insurance.

In addition to the items in the table above, we have entered into various operational commitments and agreements related to pipeline operations and to the marketing, transportation, terminaling and storage of crude oil. The majority of contractual commitments for the purchase of crude oil that are made range in term from a thirty-day evergreen to three years. A substantial portion of the contracts for the purchase of crude oil that extend beyond thirty days include cancellation provisions that allow us to cancel the contract with thirty days written notice. During the nine months ended September 30, 2005, crude oil purchases averaged approximately $629.5 million per month.

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

Other Considerations

Our operations are subject to federal, state and local laws and regulations governing the discharge of materials into the environment. 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. Although we believe our operations are in material compliance with applicable environmental laws and regulations, risks of significant costs and liabilities are inherent in pipeline operations, and we cannot assure you that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly strict environmental 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. We believe that changes in environmental laws and regulations will not have a material adverse effect on our financial position, results of operations or cash flows in the near term.

Recent Accounting Pronouncements

See discussion of new accounting pronouncements in Note 1. Organization and Basis of Presentation - New Accounting Pronouncements in the accompanying consolidated financial statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We may be exposed to market risk through changes in crude oil commodity prices and interest rates. We do not have foreign exchange risks. Our Risk Management Committee has established policies to monitor and control these market risks. The Risk Management Committee is comprised, in part, of senior executives of the Company.

We seek to maintain a position that is substantially balanced between crude oil purchases and sales and future delivery obligations. On the majority of our crude oil derivative contracts, we take the normal purchase and normal sale exclusion in accordance with Statement of Financial Accounting Standards (“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*. At September 30, 2005, we have $108.7 million of crude oil inventory for which we have entered into forward crude sales contracts to mitigate the risk of price volatility.

Occasionally, customers require pricing terms that do not allow us to balance our position. Additionally, certain pricing terms may expose us to movements in margin. On a small portion of our crude oil marketing business, we enter into derivative contracts such as swaps and other business hedging devices for which we cannot take the normal purchase and normal sale exclusion and for which we do not elect hedge accounting. The terms of these contracts are less than one year. The purpose is to balance our position or lock in a margin and, as such, do not expose us to any additional significant market risk. We mark these transactions to market and the changes in the fair value are recognized in current earnings. This results in some financial statement variability during quarterly periods; however, any unrealized gains and losses reflected in the financial statements related to marking these transactions to market are offset by realized gains and losses in different quarterly periods when the transactions are settled.

At September 30, 2005, we had $460.5 million outstanding under our variable interest rate 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 and is adjusted monthly, bimonthly, quarterly or semiannually. Utilizing the balances of our variable interest rate debt outstanding at September 30, 2005, and assuming market interest rates increase 100 basis points, the potential annual increase in interest expense would be $4.6 million.

At September 30, 2005, TE Products had outstanding $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"). At September 30, 2005, the estimated fair value of the TE Products Senior Notes was approximately $408.9 million. At September 30, 2005, we had outstanding $500.0 million principal amount of 7.625% Senior Notes due 2012 and $200.0 million principal amount of 6.125% Senior Notes due 2013. At September 30, 2005, the estimated fair value of the $500.0 million 7.625% Senior Notes and the $200.0 million 6.125% Senior Notes was approximately $555.3 million and $206.3 million, respectively.

We have utilized and expect to continue to utilize interest rate swap agreements to hedge a portion of our cash flow and fair value risks. Interest rate swap agreements are used to manage the fixed and floating interest rate mix of our total debt portfolio and overall cost of borrowing. Interest rate swaps that manage our cash flow risk reduce our exposure to increases in the benchmark interest rates underlying variable rate debt. Interest rate swaps that manage our fair value risks are intended to reduce our exposure to changes in the fair value of the fixed rate debt. Interest rate swap agreements involve the periodic exchange of payments without the exchange of the notional amount upon which the payments are based. The related amount payable to or receivable from counterparties is included as an adjustment to accrued interest.

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 nine months ended September 30, 2005, and 2004, we recognized reductions in interest expense of $4.6 million and $7.5 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. During the quarter ended September 30, 2005, 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 gain of approximately $1.3 million and $3.4 million at September 30, 2005, and December 31, 2004, respectively. Utilizing the balance of the 7.51% TE Products Senior Notes outstanding at September 30, 2005 and including the effects of hedging activities, assuming market interest rates increase 100 basis points, the potential annual increase in interest expense is $2.1 million.

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. From January 2004 through April 2004, we recognized an increase in interest expense of $2.9 million related to the difference between the fixed rate and the floating rate of interest on the interest rate swap.

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 September 30, 2005, the unamortized balance of the deferred gains was $33.5 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.

Item 4. Controls and Procedures

As of the end of the period covered by this report, our management carried out an evaluation, with the participation of our principal executive officer (the "CEO") and our principal financial officer (the "CFO"), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on those evaluations, as of September 30, 2005, the CEO and CFO concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

Through February 23, 2005, our General Partner was an indirect subsidiary of Duke Energy, and Duke Energy's Audit Services Department provided our internal audit functions. On February 24, 2005, the General Partner was acquired by DFI, an affiliate of EPCO. EPCO, using its own personnel and third party providers, will provide us with internal audit services. The transition of internal audit functions was completed in the third quarter of 2005. This change is not expected to adversely affect our internal audit process.

There has been no change in our internal control over financial reporting during the third quarter of 2005 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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 material adverse effect on our consolidated financial position, results of operations or cash flows. See discussion of legal proceedings in Note 12. Commitments and Contingencies in the accompanying consolidated financial statements.

Item 6. Exhibits

Exhibit Number	Description
3.1	Certificate of Limited Partnership of TEPPCO Partners, L.P. (Filed as Exhibit 3.2 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
3.2	Third Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P., dated September 21, 2001 (Filed as Exhibit 3.7 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
4.1	Form of Certificate representing Limited Partner Units (Filed as Exhibit 4.1 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
4.2	Form of Indenture between TE Products Pipeline Company, Limited Partnership and The Bank of New York, as Trustee, dated as of January 27, 1998 (Filed as Exhibit 4.3 to TE Products Pipeline Company, Limited Partnership's Registration Statement on Form S-3 (Commission File No. 333-38473) and incorporated herein by reference).
4.3	Form of Certificate representing Class B Units (Filed as Exhibit 4.3 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1998 and incorporated herein by reference).
4.4	Form of Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.2 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.5	First Supplemental Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.3 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.6	Second Supplemental Indenture, dated as of June 27, 2002, among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, and Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as trustee (Filed as Exhibit 4.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).

4.7	Third Supplemental Indenture among TEPPCO Partners, L.P. as issuer, 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. as Subsidiary Guarantors, and Wachovia Bank, National Association, as trustee, dated as of January 30, 2003 (Filed as Exhibit 4.7 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.1	Third Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated August 15, 2005, but effective as of February 24, 2005 (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated August 19, 2005 and incorporated herein by reference).
12.1*	Statement of Computation of Ratio of Earnings to Fixed Charges.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
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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* Filed herewith.
** Furnished herewith pursuant to Item 601(b)-(32) of Regulation S-K.

SIGNATURES

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

TEPPCO Partners, L.P.

Date: October 31, 2005	By:	/s/ BARRY R. PEARL Barry R. Pearl, President and Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC, General Partner
Date: October 31, 2005	By:	/s/ TRACY E. OHMART Tracy E. Ohmart, Chief Financial Officer of Texas Eastern Products Pipeline Company, LLC, General Partner

Exhibit 12.1

Statement of Computation of Ratio of Earnings to Fixed Charges (1)

	2000	2001	2002	2003	2004	Nine Months Ended September 30 2005
			(in thousands)			
Earnings						
Income From Continuing Operations *	65,951	92,533	105,882	104,958	115,347	100,737
Fixed Charges	51,062	68,217	73,381	93,294	80,695	68,639
Distributed Income of Equity Investment	—	40,800	30,938	28,003	47,213	28,178
Capitalized Interest	(4,559)	(4,000)	(4,345)	(5,290)	(4,227)	(4,562)
Total Earnings	112,454	197,550	205,856	220,965	239,028	192,992
Fixed Charges						
Interest Expense	44,423	62,057	66,192	84,250	72,053	60,640
Capitalized Interest	4,559	4,000	4,345	5,290	4,227	4,562
Rental Interest Factor	2,080	2,160	2,844	3,754	4,415	3,437
Total Fixed Charges	51,062	68,217	73,381	93,294	80,695	68,639
Ratio: Earnings / Fixed Charges	2.20	2.90	2.81	2.37	2.96	2.81

* Excludes minority interest, extraordinary loss, gain on sale of assets and undistributed equity earnings.

(1) Amounts presented for the years 2000 through 2004 have been modified from previous presentations. The difference between the current presentation and previous presentations is not greater than 0.11 for any given year.

Certification of Chief Executive Officer pursuant to Rule 13a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.

I, Barry R. Pearl, certify that:

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

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

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

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

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this quarterly report based on such evaluation; and

   d) Disclosed in this quarterly report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

October 31, 2005

/s/ BARRY R. PEARL
Barry R. Pearl
President and Chief Executive Officer
Texas Eastern Products Pipeline Company, LLC,
as General Partner

Exhibit 31.2

Certification of Chief Financial Officer pursuant to Rule 13a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended

I, Tracy E. Ohmart, certify that:

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

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

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

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

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this quarterly report based on such evaluation; and

   d) Disclosed in this quarterly report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

October 31, 2005

/s/ TRACY E. OHMART
Tracy E. Ohmart
Chief Financial Officer
Texas Eastern Products Pipeline Company, LLC,
as General Partner

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of TEPPCO Partners, L.P. (the “Company”) on Form 10-Q for the quarter ended September 30, 2005 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, Barry R. Pearl, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

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

/s/ BARRY R. PEARL
Barry R. Pearl
President and Chief Executive Officer
Texas Eastern Products Pipeline Company, LLC, General Partner

October 31, 2005
Date

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to such Form 10-Q. A signed original of this written statement required by Section 906 has been provided to TEPPCO Partners, L.P. and will be retained by TEPPCO Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of TEPPCO Partners, L.P. (the “Company”) on Form 10-Q for the quarter ended September 30, 2005 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, Tracy E. Ohmart, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

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

/s/ TRACY E. OHMART
Tracy E. Ohmart
Chief Financial Officer
Texas Eastern Products Pipeline Company, LLC, General Partner

October 31, 2005
Date

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to such Form 10-Q. A signed original of this written statement required by Section 906 has been provided to TEPPCO Partners, L.P. and will be retained by TEPPCO Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.