UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2006

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)

1100 Louisiana Street, Suite 1300
Houston, Texas 77002
(Address of principal executive offices, including zip code)

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

2929 Allen Parkway
P.O. Box 2521
Houston, Texas 77252-2521
(Former address)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one): Large accelerated filer x Accelerated Filer o Non-accelerated Filer 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 x

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 August 3, 2006: **75,713,554**

TEPPCO PARTNERS, L.P.

TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

TEPPCO PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS
(Unaudited)
(in thousands)

	June 30, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 185	$ 119
Accounts receivable, trade (net of allowance for doubtful accounts of $100 and $250)	830,129	803,373
Accounts receivable, related parties	2,063	5,207
Inventories	40,077	29,069
Other	56,358	61,361
Total current assets	928,812	899,129
Property, plant and equipment, at cost (net of accumulated depreciation and amortization of $512,814 and $474,332)	1,957,451	1,960,068
Equity investments	353,519	359,656
Intangible assets	360,600	376,908
Goodwill	16,944	16,944
Other assets	69,809	67,833
Total assets	$ 3,687,135	$ 3,680,538
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 828,270	$ 800,033
Accounts payable, related parties	19,661	11,836
Accrued interest	32,036	32,840
Other accrued taxes	18,510	16,532
Other	37,584	75,970
Total current liabilities	936,061	937,211
Senior notes	1,106,677	1,119,121
Other long-term debt	445,000	405,900
Deferred tax liability	514	—
Other liabilities and deferred credits	27,233	16,936
Commitments and contingencies		
Partners' capital:		
Accumulated other comprehensive (loss) income	(262)	11
General partner's interest	(70,145)	(61,487)

Limited partners' interests	1,242,057	1,262,846
Total partners' capital	1,171,650	1,201,370
Total liabilities and partners' capital	$ 3,687,135	$ 3,680,538

See accompanying Notes to Unaudited Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Operating revenues:				
Sales of petroleum products	$ 2,287,266	$ 1,961,302	$ 4,683,612	$ 3,346,369
Transportation – Refined products	39,443	37,834	71,242	72,799
Transportation – LPGs	13,354	14,470	42,775	46,701
Transportation – Crude oil	10,544	9,042	19,467	18,214
Transportation – NGLs	10,738	11,387	21,391	21,606
Gathering – Natural gas	41,459	36,956	82,834	73,516
Other	22,248	16,394	40,100	31,971
Total operating revenues	2,425,052	2,087,385	4,961,421	3,611,176
Costs and expenses:				
Purchases of petroleum products	2,254,756	1,941,890	4,625,796	3,312,980
Operating expense	55,275	43,721	101,778	86,396
Operating fuel and power	12,987	11,546	27,284	22,616
General and administrative	9,158	6,100	18,359	13,305
Depreciation and amortization	28,676	26,138	57,433	51,749
Taxes – other than income taxes	6,048	4,241	11,359	9,647
Gains on sales of assets	(18)	(68)	(1,396)	(566)
Total costs and expenses	2,366,882	2,033,568	4,840,613	3,496,127
Operating income	58,170	53,817	120,808	115,049
Interest expense – net	(19,198)	(21,627)	(40,341)	(40,914)
Equity earnings	2,674	7,751	3,663	11,845
Other income – net	454	135	1,353	401
Income before deferred income tax expense	42,100	40,076	85,483	86,381
Deferred income tax expense	514	—	514	—
Income from continuing operations	41,586	40,076	84,969	86,381
Income (loss) from discontinued operations	(110)	846	1,497	1,970
Gain on sale of discontinued operations	(12)	—	17,872	—
Discontinued operations	(122)	846	19,369	1,970
Net income	$ 41,464	$ 40,922	$ 104,338	$ 88,351

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Net Income Allocation:				
Limited Partner Unitholders:				
Income from continuing operations	$ 29,360	$ 28,154	$ 59,988	$ 61,101
Income from discontinued operations	(86)	594	13,674	1,394
Total Limited Partner Unitholders net income allocation	29,274	28,748	73,662	62,495
General Partner:				

Income from continuing operations	12,226	11,922	24,981	25,280
Income from discontinued operations	(36)	252	5,695	576
Total General Partner net income allocation	12,190	12,174	30,676	25,856
Total net income allocated	$ 41,464	$ 40,922	$ 104,338	$ 88,351
Basic and diluted net income per Limited Partner Unit:				
Continuing operations	$ 0.42	$ 0.42	$ 0.85	$ 0.94
Discontinued operations	—	0.01	0.20	0.02
Basic and diluted net income per Limited Partner Unit	$ 0.42	$ 0.43	$ 1.05	$ 0.96
Weighted average Limited Partner Units outstanding	69,964	66,559	69,964	64,789

See accompanying Notes to Unaudited Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

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

	Six Months Ended June 30,	
	2006	**2005**
Cash flows from operating activities:		
Net income	$ 104,338	$ 88,351
Adjustments to reconcile net income to cash provided by continuing operating activities:		
Income from discontinued operations	(19,369)	(1,970)
Deferred income tax expense	514	—
Depreciation and amortization	57,433	51,749
Earnings in equity investments	(3,663)	(11,845)
Distributions from equity investments	16,297	19,047
Gains on sales of assets	(1,396)	(566)
Non-cash portion of interest expense	840	810
Increase in accounts receivable, trade	(26,756)	(133,049)
Decrease in accounts receivable, related parties	3,144	8,443
Increase in inventories	(10,981)	(70,562)
(Increase) decrease in other current assets	5,003	(15,265)
Increase in accounts payable and accrued expenses	14,374	116,025
Increase (decrease) in accounts payable, related parties	7,825	(19,234)
Other	(6,069)	(4,232)
Net cash provided by continuing operating activities	141,534	27,702
Net cash provided by discontinued operations	1,521	2,251
Net cash provided by operating activities	143,055	29,953
Cash flows from investing activities:		
Proceeds from the sales of assets	39,750	510
Purchase of assets	—	(42,482)
Investment in Centennial Pipeline LLC	(2,500)	—
Investment in Mont Belvieu Storage Partners, L.P.	(1,720)	(1,109)
Cash paid for linefill on assets owned	(1,371)	(5,353)
Capital expenditures	(82,463)	(82,963)
Net cash used in investing activities	(48,304)	(131,397)
Cash flows from financing activities:		
Proceeds from revolving credit facility	305,550	299,307
Repayments on revolving credit facility	(266,450)	(374,307)
Issuance of Limited Partner Units, net	—	278,832
Distributions paid	(133,785)	(117,316)
Net cash provided by (used in) financing activities	(94,685)	86,516
Net increase (decrease) in cash and cash equivalents	66	(14,928)
Cash and cash equivalents at beginning of period	119	16,422
Cash and cash equivalents at end of period	$ 185	$ 1,494
Supplemental disclosure of cash flows:		
Cash paid for interest (net of amounts capitalized)	$ 42,074	$ 41,067

See accompanying Notes to Unaudited Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

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

	Outstanding Limited Partner Units	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive Income (Loss)	Total
Partners' capital at December 31, 2005	69,963,554	$ (61,487)	$ 1,262,846	$ 11	$ 1,201,370
Net income allocation	—	30,676	73,662	—	104,338
Cash distributions	—	(39,334)	(94,451)	—	(133,785)
Changes in fair values of interest rate cash flow hedges	—	—	—	1,671	1,671
Changes in fair values of interest rate cash flow hedges	—	—	—	(1,671)	(1,671)
Changes in fair values of crude oil cash flow hedges	—	—	—	(273)	(273)
Partners' capital at June 30, 2006	69,963,554	$ (70,145)	$ 1,242,057	$ (262)	$ 1,171,650

See accompanying Notes to Unaudited Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)
(in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Net income	$ 41,464	$ 40,922	$ 104,338	$ 88,351
Changes in fair values of interest rate cash flow hedges	1,671	—	1,671	—
Changes in fair values of interest rate cash flow hedges	(1,671)	—	(1,671)	—
Changes in fair values of crude oil cash flow hedges	(509)	—	(273)	—
Comprehensive income	$ 40,955	$ 40,922	$ 104,065	$ 88,351

See accompanying Notes to Unaudited 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." 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.

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.

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

In connection with our formation, the Company received 2,500,000 Deferred Participation Interests ("DPIs"). Effective April 1, 1994, the DPIs were converted to Limited Partner Units, but they have not been listed for trading on the New York Stock Exchange. These Limited Partner Units were assigned to Duke Energy when ownership of the Company was transferred from Duke Energy to DEFS in 2000. On February 24, 2005, DFI entered into an LP Unit Purchase and Sale Agreement with Duke Energy and purchased these 2,500,000 Limited Partner Units for $104.0 million. As of June 30, 2006, none of these Limited Partner Units had been sold by DFI.

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 June 30, 2006, and the results of our operations and cash flows for the periods presented. The results of operations for the three months and six months ended June 30, 2006, are not necessarily indicative of results of our operations for the full year 2006. You should read these interim financial statements in conjunction with our consolidated financial statements and notes thereto presented in our Current Report on Form 8-K filed on June 16, 2006, which recast certain information from our Annual Report on Form 10-K for the year ended December 31, 2005, as discontinued operations. We have reclassified certain amounts from prior periods to conform to the current presentation.

Business Segments

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

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

Net Income Per Unit

Basic net income per Limited Partner Unit ("Unit" or "Units") is computed by dividing net income, after deduction of the General Partner's interest, by the weighted average number of Units outstanding (a total of 70.0 million Units and 66.6 million Units for the three months ended June 30, 2006 and 2005, respectively, and a total of 70.0 million Units and 64.8 million Units for the six months ended June 30, 2006 and 2005, respectively). 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). The General Partner was allocated $12.2 million (representing 29.4%) and $12.2 million (representing 29.75%) of our net income for the three months ended June 30, 2006 and 2005, respectively, and $30.7 million (representing 29.4%) and $25.9 million (representing 29.27%) of our net income for the six months ended June 30, 2006 and 2005, respectively. The General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase, in accordance with the Third Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P. ("Partnership Agreement").

Diluted net income per Unit equaled basic net income per Unit for each of the three-month and six-month periods ended June 30, 2006 and 2005, as there were no dilutive instruments outstanding.

Deferred Income Tax Expense for Certain Pipeline Operations

In May 2006, the State of Texas enacted a new business tax (the "Texas Margin Tax") that replaces its existing franchise tax. In general, legal entities that do business in Texas are subject to the new margin tax. Limited partnerships, limited liability companies, corporations, limited liability partnerships and joint ventures are examples of the types of entities subject to the Texas Margin Tax. As a result of the change in tax law, our tax status in the state of Texas changed from nontaxable to taxable. The tax is considered an income tax for purposes of adjustments to deferred tax liability, as the tax is determined by applying a tax rate to a base that considers both revenues and expenses. Our deferred income tax expense for state taxes relates only to Texas Margin Tax obligations. The Texas Margin Tax becomes effective for franchise tax reports due on or after January 1, 2008. The Texas Margin Tax due in 2008 will be based on revenues earned during the 2007 fiscal year.

The Texas Margin Tax is assessed at 1% of Texas-sourced taxable margin, which is computed as the lesser of (i) 70% of total revenue or (ii) total revenues less (a) cost of goods sold or (b) compensation. The deferred tax liability shown on our consolidated balance sheet reflects the net tax effect of temporary differences related to items such as property, plant and equipment; therefore, the deferred tax liability is noncurrent. We have calculated and recorded an estimated deferred tax liability of approximately $0.5 million associated with the Texas Margin Tax. The non-cash offsetting charge is shown on our unaudited consolidated statements of income as deferred income tax expense for the three months and six months ended June 30, 2006.

Since the Texas Margin Tax is determined by applying a tax rate to a base that considers both revenues and expenses, it has characteristics of an income tax. Accordingly, we determined the Texas Margin Tax should be accounted for as an income tax in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 109, *Accounting for Income Taxes*.

Asset Retirement Obligations

During the second quarter of 2006, we recorded $0.3 million of expense, included in depreciation and amortization expense, related to a conditional asset retirement obligation. Additionally, we recorded a $0.4 million liability, which represents the fair value, as measured at June 30, 2006, of the conditional asset retirement obligation related to structural restoration work to be completed on leased office space that is required upon our anticipated office lease termination. This conditional asset retirement obligation was not previously recorded, due to the indeterminate range of settlement dates and settlement methods, during the implementation of SFAS No. 143, *Accounting for Asset Retirement Obligations*, and Financial Accounting Standards Board ("FASB") Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143*, which we adopted on January 1, 2003 and December 31, 2005, respectively. With the availability of new information, we were able to assign probabilities for settlement dates and settlement methods for use in an expected present value measurement of fair value.

New Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123(R) (revised 2004), *Share-Based Payment*. 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) requires that the cost resulting from all share-based payment transactions be recognized in the financial statements at fair value. In April 2005, both the FASB and the Securities and Exchange Commission decided to delay the effective date for public companies to implement SFAS 123(R). SFAS 123(R) became effective for public companies for annual periods beginning after June 15, 2005. Accordingly, we adopted SFAS 123(R) in the first quarter of 2006. We adopted SFAS 123(R) under the modified prospective transition method. We have determined that our 1999 and 2005 Phantom Unit Plans are liability awards under the provisions of this statement. No additional compensation expense has been recorded in connection with the adoption of SFAS 123(R) as we have historically recorded the associated liabilities at fair value. The adoption of SFAS 123(R) did not have a material effect on our financial position, results of operations or cash flows.

In June 2005, the Emerging Issues Task Force ("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. Although this EITF did not directly impact us, it did impact our General Partner. Our General Partner

adopted this EITF on January 1, 2006. The adoption of EITF 04-5 resulted in the consolidation of our results of operations and balance sheet into its consolidated financial statements.

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. The adoption of SFAS 154 did not have a material effect on our financial position, results of operations or cash flows.

In September 2005, the EITF reached consensus in EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, to define when a purchase and a sale of inventory with the same party that operates in the same line of business should be considered a single nonmonetary transaction subject to APB Opinion No. 29, *Accounting for Nonmonetary Transactions*. Two or more inventory transactions with the same party should be combined if they are entered into in contemplation of one another. The EITF also requires entities to account for exchanges of inventory in the same line of business at fair value or recorded amounts based on inventory classification. The guidance in EITF 04-13 is effective for new inventory arrangements entered into in reporting periods beginning after March 15, 2006. We adopted EITF 04-13 on April 1, 2006, which resulted in crude oil inventory purchases and sales under buy/sell transactions, which were previously recorded as gross purchases and sales, to be treated as inventory exchanges in our consolidated statements of income. EITF 04-13 reduced gross revenues and purchases, but did not have a material effect on our financial position, results of operations or cash flows. The treatment of buy/sell transactions under EITF 04-13 reduced the relative amount of revenues and purchases of petroleum products on our consolidated statement of income by approximately $313.7 million for the periods ended June 30, 2006. The revenues and purchases of petroleum products associated with buy/sell transactions that are reported on a gross basis in our consolidated statements of income for the three months ended June 30, 2005, and for the six months ended June 30, 2006 and 2005, are approximately $326.9 million, $589.1 million and $403.3 million, respectively.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments*, which amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* and SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. This statement improves the financial reporting of certain hybrid financial instruments and simplifies the accounting for these instruments. SFAS 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, clarifies which interest-only and principal-only strips are not subject to the requirements of SFAS 133, establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation, clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives, and amends SFAS 140 to eliminate the prohibition on a qualifying special-purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. SFAS 155 is effective for all financial instruments acquired, issued, or subject to a remeasurement event occurring after the fiscal year that begins after September 15, 2006 (January 1, 2007). At June 30, 2006, we did not have any hybrid financial securities outstanding and, as such, we do not believe that adoption of this statement will have a material effect on our financial position, results of operations or cash flows, unless such hybrid securities are issued by us prior to SFAS 155 becoming effective.

In June 2006, the EITF reached consensus in EITF 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)*. The accounting guidance permits companies to elect to present on either a gross or net basis sales and other taxes that are imposed on and concurrent with individual revenue-producing transactions between a seller and a customer. The gross basis includes the taxes in revenues and costs; the net basis excludes the taxes from revenues. The accounting guidance does not apply to tax systems that are based on gross receipts or total revenues. EITF 06-3 requires companies to disclose their policy for presenting the taxes and disclose any amounts presented on a gross basis if those amounts are significant. The guidance in EITF 06-3 is effective January 1, 2007. As a matter of policy, we report such taxes on a net basis. We believe that adoption of EITF 06-3 will not 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, but instead requires testing for impairment at least annually. We test goodwill 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, to those reporting units. We then determine the fair value of each reporting unit and compare it to the carrying value of the reporting unit. We will continue to compare the fair value of each reporting unit to its carrying value on an annual basis to determine if an impairment loss has occurred. There have been no goodwill impairment losses recorded since the adoption of SFAS 142.

The following table presents the carrying amount of goodwill at both June 30, 2006 and December 31, 2005, by business segment (in thousands):

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

Other Intangible Assets

The following table reflects the components of intangible assets, including excess investments, being amortized at June 30, 2006, and December 31, 2005 (in thousands):

	June 30, 2006		December 31, 2005	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible assets:				
Gathering and transportation agreements	$ 464,337	$ (133,682)	$ 464,337	$ (118,921)
Fractionation agreement	38,000	(15,675)	38,000	(14,725)
Other	9,898	(2,278)	10,226	(2,009)
Subtotal	512,235	(151,635)	512,563	(135,655)
Excess investments:				
Centennial Pipeline LLC	33,390	(14,651)	33,390	(12,947)
Seaway Crude Pipeline Company	27,100	(4,110)	27,100	(3,764)
Subtotal	60,490	(18,761)	60,490	(16,711)
Total intangible assets	$ 572,725	$ (170,396)	$ 573,053	$ (152,366)

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 $8.0 million and $7.0 million for the three months ended June 30, 2006 and 2005, respectively, and $16.0 million and $14.1 million for the six months ended June 30, 2006 and 2005 respectively. Amortization expense on excess investments included in equity earnings was $1.2 million and $1.3 million for the three months ended June 30, 2006 and 2005, respectively, and $2.4 million and $2.5 million for the six months ended June 30, 2006 and 2005, respectively.

The values assigned to our intangible assets for natural gas gathering contracts on the Jonah Gas Gathering System (“Jonah” or “Jonah system”) and the Val Verde Gas Gathering System (“Val Verde”) are amortized on a unit-of-production basis, based upon the actual throughput of the systems compared to the expected total throughput for the lives of the contracts. On a quarterly basis, we may obtain limited production forecasts and updated throughput estimates from some of the producers on the systems, and as a result, we evaluate the remaining expected useful lives of the contract assets based on the best available information. Revisions to these estimates may occur as additional production information is made available to us.

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

The value assigned to our excess investment in Centennial Pipeline LLC was created upon its formation. Approximately $30.0 million is related to a contract and is being amortized on a unit-of-production basis based upon the volumes transported under the contract compared to the guaranteed total throughput of the contract over a 10-year life. The remaining $3.4 million is related to a pipeline and is being amortized on a straight-line basis over the life of the pipeline, which is 35 years. The value assigned to our excess investment in Seaway Crude Pipeline

Company was created upon acquisition of our 50% ownership interest in 2000. We are amortizing the $27.1 million excess investment on a straight-line basis over a 39-year life related primarily to the life of the pipeline.

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

	Intangible Assets	Excess Investments
2006	$ 32,254	$ 4,691
2007	33,379	5,113
2008	32,950	5,438
2009	30,703	6,878
2010	27,322	7,042

NOTE 3. INTEREST RATE SWAPS

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 of 147 basis points, and receives a fixed rate of interest of 7.51%. During the six months ended June 30, 2006 and 2005, we recognized reductions in interest expense of $1.2 million and $3.3 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. During the quarters ended June 30, 2006 and 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 loss of approximately $11.3 million and $0.9 million at June 30, 2006, and December 31, 2005, 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 June 30, 2006, the unamortized balance of the deferred gains was $30.2 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 for 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.

On January 20, 2006, we entered into interest rate swap agreements with a total notional amount of $200.0 million to hedge our exposure to increases in the benchmark interest rate underlying our variable rate revolving credit facility. These interest rate swaps mature in January 2008. For the period from January 20, 2006 through June 30, 2006, changes in the fair value of the swaps were recognized in earnings, which for the six months ended June 30, 2006, was a $2.5 million reduction to interest expense. Under the swap agreements, we pay a fixed rate of interest ranging from 4.67% to 4.695% and receive a floating rate based on a three-month U.S. Dollar LIBOR rate. Because these swaps will be designated as cash flow hedges effective in the third quarter of 2006, future changes in fair value, to the extent the swaps are effective, will be recognized in other comprehensive income until the hedged interest costs are recognized in earnings.

NOTE 4. ACQUISITIONS

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, and we allocated the purchase price to property, plant and equipment. We have integrated these assets into our South Texas pipeline system, which is included in our Upstream Segment.

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.

NOTE 5. DISPOSITIONS AND DISCONTINUED OPERATIONS

Pioneer Plant

On March 31, 2006, we sold our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise Products Partners L.P. ("Enterprise") for $38.0 million in cash. The Pioneer plant was not an integral part of our Midstream Segment operations, and natural gas processing is not a core business. We have no continuing involvement in the operations or results of this plant. This transaction was reviewed and approved by the Audit and Conflicts Committee of the board of directors of our General Partner and a fairness opinion was rendered by an independent third-party. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of the Pioneer plant at March 31, 2006, prior to the sale, was $19.7 million. Costs associated with the completion of the transaction were approximately $0.4 million.

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the three months and six months ended June 30, 2006 and 2005, are presented below (in thousands):

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Sales of petroleum products	$ 18	$ 2,315	$ 3,828	$ 4,457
Other	11	680	932	1,352
Total operating revenues	29	2,995	4,760	5,809
Purchases of petroleum products	139	1,806	3,000	3,176
Operating expenses	—	158	182	296
Depreciation and amortization	—	154	51	306
Taxes – other than income taxes	—	31	30	61
Total costs and expenses	139	2,149	3,263	3,839
Income (loss) from discontinued operations	$ (110)	$ 846	$ 1,497	$ 1,970

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

	December 31, 2005
Inventories	$ 7
Property, plant and equipment, net	19,812
Assets of discontinued operations	$ 19,819

Cash flows from discontinued operations for the six months ended June 30, 2006 and 2005, are presented below (in thousands):

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Cash flows from operating activities:		
Net income	$ 19,369	$ 1,970
Depreciation and amortization	51	306
Gain on sale of Pioneer plant	(17,872)	—
Increase in inventories	(27)	(25)
Cash flow from discontinued operations	$ 1,521	2,251

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 June 30, 2006, and December 31, 2005. The major components of inventories were as follows (in thousands):

	June 30, 2006	December 31, 2005
Crude oil (1)	$ 10,860	$ 3,021
Refined products	—	4,461
LPGs	13,278	7,403

Lubrication oils and specialty chemicals		6,859		5,740
Materials and supplies		9,062		8,203
Other		18		241
Total	$	40,077	$	29,069

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(1) At June 30, 2006, 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. We operate the Seaway assets. Seaway owns a pipeline that carries mostly imported crude oil from a marine terminal at Freeport, Texas, to Cushing, Oklahoma, and from a marine terminal at Texas City, Texas, to refineries in the Texas City and Houston, Texas, areas. The Seaway Crude Pipeline Company Partnership Agreement provides for varying participation ratios throughout the life of Seaway. From June 2002 through December 31, 2005, we received 60% of revenue and expense of Seaway. For 2006, we are allocated 60% of revenue and expense for the period January 1, 2006, through May 12, 2006, and 40% for the period May 13, 2006, through December 31, 2006. Our share of revenue and expense of Seaway is 47% for 2006. Thereafter, we will receive 40% of revenue and expense of Seaway. During the six months ended June 30, 2006 and 2005, we received distributions from Seaway of $8.5 million and $11.7 million, respectively. During the six months ended June 30, 2006 and 2005, we did not invest any additional funds in Seaway.

TE Products owns a 50% ownership interest in Centennial Pipeline 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 six months ended June 30, 2006, TE Products contributed $2.5 million to Centennial. During the six months ended June 30, 2005, TE Products did not invest any additional funds in Centennial. TE Products has received no cash distributions from Centennial since its formation.

TE Products owns a 50% ownership interest in Mont Belvieu Storage Partners, L.P. ("MB Storage"), and Louis Dreyfus Energy Services L.P. ("Louis Dreyfus") owns the remaining 50% interest. MB Storage owns storage capacity at the Mont Belvieu fractionation and storage complex and a short haul transportation shuttle system that ties Mont Belvieu, Texas, to the upper Texas Gulf Coast energy marketplace. MB Storage is a service-oriented, fee-based venture serving the fractionation, refining and petrochemical industries with substantial capacity and flexibility for the transportation, terminaling and storage of NGLs, LPGs and refined products. MB Storage has no commodity trading activity. TE Products operates the facilities for MB Storage (see Note 13 regarding expected divestiture of MB Storage).

For the years ended December 31, 2006 and 2005, TE Products receives 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 Agreement of Limited Partnership of MB Storage. TE Products' share of MB Storage's earnings may be 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 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 six months ended June 30, 2006 and 2005, TE Products' sharing ratios in the earnings of MB Storage were approximately 61.4% and 62.6%, respectively. During the six months ended June 30, 2006, TE Products received distributions from MB Storage of $7.8 million and contributed $1.7 million to MB Storage. During the six months ended June 30, 2005, TE Products received distributions of $7.3 million from MB Storage and contributed $1.1 million to MB Storage.

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 six months ended June 30, 2006 and 2005, is presented below (in thousands):

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Revenues	$ 82,782	$ 81,046
Net income	17,842	28,191

Summarized combined balance sheet information for Seaway, Centennial and MB Storage as of June 30, 2006, and December 31, 2005, is presented below (in thousands):

	June 30, 2006	December 31, 2005
Current assets	$ 56,462	$ 60,082
Noncurrent assets	626,258	630,212
Current liabilities	19,559	32,242
Long-term debt	150,000	150,000
Noncurrent liabilities	20,933	13,626
Partners' capital	492,228	494,426

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 may not be redeemed prior to their maturity on 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 the following redemption prices (expressed in percentages of the principal amount) during the twelve months beginning January 15 of the years indicated:

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

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

The TE Products Senior Notes do not have sinking fund requirements. Interest on the TE Products Senior Notes is payable semiannually in arrears on January 15 and July 15 of each year. The TE Products Senior Notes are unsecured obligations of TE Products and rank pari passu with all other unsecured and unsubordinated indebtedness of TE Products. The indenture governing the TE Products Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of June 30, 2006, 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 June 30, 2006, 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 June 30, 2006, 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 June 30, 2006, and December 31, 2005 (in millions):

	Face Value	Fair Value June 30, 2006	Fair Value December 31, 2005
6.45% TE Products Senior Notes, due January 2008	$ 180.0	$ 181.0	$ 183.7
7.625% Senior Notes, due February 2012	500.0	526.9	552.0
6.125% Senior Notes, due February 2013	200.0	196.1	205.6
7.51% TE Products Senior Notes, due January 2028	210.0	221.1	224.1

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 3).

Revolving Credit Facility

On October 21, 2004, we entered into a $600.0 million unsecured revolving credit facility with a five year term, including the issuance of letters of credit of up to $100.0 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. Financial covenants in the Revolving Credit Facility require that we maintain a ratio of Consolidated Funded Debt to Pro Forma EBITDA (as defined and calculated in the facility) of less than 4.75 to 1.00 (subject to adjustment for specified acquisitions) and a ratio of EBITDA to Interest Expense (as defined and calculated in the facility) of at least 3.00 to 1.00, in each case with respect to specified twelve month periods. Other 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), incur liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets. On February 23, 2005, we amended our Revolving Credit Facility to remove the requirement that DEFS must at all times own, directly or indirectly, 100% of our General Partner, to allow for its acquisition by DFI (see Note 1). During the second quarter of 2005, we used a portion of the proceeds from an equity offering in May 2005 to repay a portion of the Revolving Credit Facility. On December 13, 2005, we again amended our Revolving Credit Facility as follows:

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

At June 30, 2006, $445.0 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 5.8%. At June 30, 2006, we were in compliance with the covenants of this credit facility. Please see Note 16 for information regarding an amendment to the Revolving Credit Facility.

The following table summarizes the principal amounts outstanding under all of our debt instruments as of June 30, 2006, and December 31, 2005 (in thousands):

	June 30, 2006	December 31, 2005
Revolving Credit Facility, due December 2010	$ 445,000	$ 405,900
6.45% TE Products Senior Notes, due January 2008	179,952	179,937
7.625% Senior Notes, due February 2012	498,770	498,659
6.125% Senior Notes, due February 2013	199,059	198,988
7.51% TE Products Senior Notes, due January 2028	210,000	210,000
Total borrowings	1,532,781	1,493,484
Adjustment to carrying value associated with hedges of fair valueswaps	18,896	31,537
Total Debt Instruments	$ 1,551,677	$ 1,525,021

Letter of Credit

At June 30, 2006, we had outstanding a $14.2 million standby letter of credit in connection with crude oil purchased in the second quarter of 2006. The payable related to these purchases of crude oil is expected to be paid during the third quarter of 2006.

NOTE 9. PARTNERS' CAPITAL AND DISTRIBUTIONS

Quarterly Distributions of Available Cash

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

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

The following table reflects the allocation of total distributions paid during the six months ended June 30, 2006 and 2005 (in thousands, except per Unit amounts):

	Six Months Ended June 30, 2006	2005
Limited Partner Units	$ 94,451	$ 83,473
General Partner Ownership Interest	1,928	1,703
General Partner Incentive	37,406	32,140
Total Cash Distributions Paid	$ 133,785	$ 117,316
Total Cash Distributions Paid Per Unit	$ 1.350	$ 1.325

On August 7, 2006, we will pay a cash distribution of $0.675 per Unit for the quarter ended June 30, 2006. The second quarter 2006 cash distribution will total $72.4 million.

General Partner's Interest

As of June 30, 2006, and December 31, 2005, we had deficit balances of $70.1 million and $61.5 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 six months ended June 30, 2006, the General Partner was allocated $30.7 million (representing 29.4%) of our net income and received $39.3 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 June 30, 2006, and December 31, 2005, 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 reasonable discretion. Cash distributions in excess of net income allocations and capital contributions during the year ended December 31, 2005, and the six months ended June 30, 2006, resulted in deficits in the General Partner's equity account at December 31, 2005, and June 30, 2006. 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 our 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.

EPCO Proposal

On April 20, 2006, EPCO submitted a proposal to the Audit and Conflicts Committee of our General Partner's Board of Directors to reduce the General Partner's maximum percentage interest in our quarterly distributions from 50% to 25% with respect to that portion of our quarterly cash distribution to partners that exceeds $0.325 per Unit. In exchange for the agreement to reduce its maximum percentage interest in our quarterly distributions, our General Partner would receive a number of newly-issued Units that, based on the distribution rate and the number of Units outstanding at the time of issuance, would result in our General Partner receiving cash distributions from the newly-issued Units and from its reduced maximum percentage interest in our quarterly distributions that would approximately equal the cash distributions our General Partner would have received from its maximum percentage interest in our quarterly distributions without reduction. Based on our distribution rate and outstanding Units as of the date of the filing of this Report, the number of newly-issued Units issued to the General Partner would be approximately 14.1 million. We filed with the Securities and Exchange Commission a preliminary proxy statement that outlines the EPCO proposal for which we will solicit approval from our unitholders at a special meeting. The proxy statement also contains separate proposals for the adoption of an employee Unit purchase plan and a long term incentive plan.

NOTE 10. RELATED PARTY TRANSACTIONS

EPCO and Affiliates and Duke Energy, DEFS and Affiliates

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

The following table summarizes the related party transactions with EPCO and affiliates and DEFS and affiliates for the three months and six months ended June 30, 2006 and 2005 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Revenues from EPCO and affiliates: (1)				

Sales of petroleum products	$ 2.0	$ —	$ 2.1	$ —
Transportation – NGLs	2.9	2.0	4.6	2.9
Transportation – LPGs	0.6	0.7	2.4	1.6
Costs and Expenses from EPCO and affiliates: (1)				
Payroll, administrative and other (2)	33.4	8.8	62.4	8.8
Purchases of petroleum products	10.8	—	16.4	—
Revenues from DEFS and affiliates: (3)				
Sales of petroleum products	—	—	—	4.3
Transportation – NGLs	—	—	—	2.8
Gathering – Natural gas – Jonah	—	—	—	0.5
Transportation – LPGs	—	—	—	0.7
Other operating revenues	—	—	—	2.4
Costs and Expenses from DEFS and affiliates: (3)				
Payroll, administrative and other (5) (4)	—	—	—	16.2
Purchases of petroleum products	—	—	—	38.5

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

(2) Substantially all of these costs were related to payroll, payroll related expenses and administrative expenses, including reimbursements related to employee benefits and employee benefit plans, incurred in managing us and our subsidiaries in accordance with the ASA.

(3) Operating revenues earned and expenses incurred from activities with DEFS and its affiliates are considered related party transactions prior to February 23, 2005, at which time a change in ownership of the General Partner occurred.

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

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

At June 30, 2006 and December 31, 2005, we had a receivable from EPCO and affiliates of $1.1 million and $4.3 million, respectively, related to sales and transportation services provided to EPCO and affiliates. At June 30, 2006 and December 31, 2005, we had a payable to EPCO and affiliates of $16.9 million and $9.8 million, respectively, related to direct payroll, payroll related costs and other operational related costs.

Beginning February 24, 2005, the majority of our insurance coverage, including property, liability, business interruption, auto and directors and officers' liability insurance, was obtained through EPCO. For the three months and six months ended June 30, 2006, we incurred insurance expense related to premiums paid by EPCO of $4.4 million and $7.1 million, respectively, and $2.1 million for the three months and six months ended June 30, 2005.

At June 30, 2006 and December 31, 2005, we had insurance reimbursement receivables due from EPCO of $1.8 million and $1.3 million, respectively.

On March 31, 2006, we sold our ownership interest in the Jonah Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming to an affiliate of Enterprise for $38.0 million. We recognized a gain of approximately $17.9 million on the sale of this asset (see Note 5).

Jonah Joint Venture

On August 1, 2006, Enterprise (through an affiliate) became our joint venture partner by acquiring an interest in our Jonah Gas Gathering Company, the partnership through which we owned the Jonah system. Prior to entering into the joint venture, Enterprise had managed the construction of the Phase V expansion and funded the initial costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and Enterprise intend to continue the Phase V expansion, which is expected to increase the system capacity of the Jonah system from 1.5 billion cubic feet per day ("Bcf/d") to approximately 2.4 Bcf/d and to significantly reduce system operating pressures, which is anticipated to lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is expected to increase the system gathering capacity to approximately 2.0 Bcf/d, is scheduled to be completed in the first quarter of 2007 at an estimated cost of approximately $275.0 million. The second portion of the expansion is expected to cost approximately $140.0 million and be completed by the end of 2007.

Enterprise will continue to manage the Phase V construction project. We are entitled to all distributions from the joint venture until specified milestones are achieved, at which point, Enterprise will be entitled to receive 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. After subsequent milestones are achieved, we and Enterprise will share distributions based on a formula that takes into account the capital contributions of the parties, including expenditures by us prior to the expansion. In the third quarter of 2006, we will reimburse Enterprise for 50% of the Phase V cost incurred by it through August 1, 2006 (including its cost of capital). From August 1, 2006, we and Enterprise equally share the costs of the Phase V expansion. Upon completion of the expansion project and based on the formula in the partnership agreement, we expect to own an interest in Jonah Gas Gathering Company of approximately 80%, with Enterprise owning the remaining 20% and serving as operator and with further costs being allocated based on such ownership interests. The joint venture will be governed by a management committee comprised of two representatives approved by Enterprise and two representatives approved by us, each with equal voting power. This transaction was reviewed and approved by the Audit and Conflicts Committee of the board of directors of our General Partner. Through June 30, 2006, Enterprise had incurred approximately $106.9 million of costs related to the expansion, of which $97.8 million has been paid to vendors by Enterprise.

NOTE 11. EMPLOYEE BENEFIT PLANS

Retirement Plans

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

On May 27, 2005, the TEPPCO RCBP and the TEPPCO SBP were amended. Effective May 31, 2005, participation in the TEPPCO RCBP was frozen, and no new participants were eligible to be covered by the plan after that date. Effective June 1, 2005, EPCO adopted the TEPPCO RCBP and the TEPPCO SBP for the benefit of its employees providing services to us. Effective December 31, 2005, all plan benefits accrued were frozen, participants received no additional pay credits after that date, and all plan participants were 100% vested regardless of their years of service. The TEPPCO RCBP plan was terminated effective December 31, 2005, and plan participants have the option to receive their benefits either through a lump sum payment in 2006 or through an annuity. In April 2006, we received a determination letter from the IRS providing IRS approval of the plan

termination. For those plan participants who elect to receive an annuity, we will purchase an annuity contract from an insurance company in which the plan participant owns the annuity, absolving us of any future obligation to the participant. Participants in the TEPPCO SBP received pay credits through November 30, 2005, and received lump sum benefit payments in December 2005. Both the RCBP and SBP benefit payments are discussed below.

In June 2005, we recorded a curtailment charge of $0.1 million in accordance with SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, as a result of the TEPPCO RCBP and TEPPCO SBP amendments. As of May 31, 2005, the following assumptions were changed for purposes of determining the net periodic benefit costs for the remainder of 2005: the discount rate, the long-term rate of return on plan assets, and the assumed mortality table. The discount rate was decreased from 5.75% to 5.00% to reflect rates of returns on bonds currently available to settle the liability. The expected long-term rate of return on plan assets was changed from 8% to 2% due to the movement of plan funds from equity investments into short-term money market funds. The mortality table was changed to reflect overall improvements in mortality experienced by the general population. The curtailment charge arose due to the accelerated recognition of the unrecognized prior service costs. We recorded additional settlement charges of approximately $0.2 million in the fourth quarter of 2005 relating to the TEPPCO SBP. We expect to record additional settlement charges of approximately $4.0 million during the third quarter of 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 six months ended June 30, 2006 and 2005, were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Service cost benefit earned during the period	$ —	$ 1,069	$ —	$ 2,099
Interest cost on projected benefit obligation	255	234	506	468
Expected return on plan assets	(115)	(223)	(236)	(520)
Amortization of prior service cost	—	1	—	3
Amortization of actuarial losses	35	30	70	56
SFAS 88 curtailment charge	—	50	—	50
Net pension benefits costs	$ 175	$ 1,161	$ 340	$ 2,156

Other Postretirement Benefits

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

In May 2005, benefits provided to employees under the TEPPCO OPB were changed. Employees eligible for these benefits received them through December 31, 2005, however, effective December 31, 2005, these benefits were terminated. As a result of this change in benefits and in accordance with SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, we recorded a curtailment credit of approximately $1.7 million in our accumulated postretirement obligation which reduced our accumulated postretirement obligation to the total of the expected remaining 2005 payments under the TEPPCO OPB. The employees participating in this plan at that time were transferred to DEFS, who is expected 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 months and six months ended June 30, 2006 and 2005, were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Service cost benefit earned during the period	$ —	$ 32	$ —	$ 81
Interest cost on accumulated postretirement benefit obligation	—	28	—	69
Amortization of prior service cost	—	21	—	53
Recognized net actuarial loss	—	2	—	4
SFAS 106 curtailment credit	—	(1,676)	—	(1,676)
Net postretirement benefits costs	$ —	$ (1,593)	$ —	$ (1,469)

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 is expected to 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 do not expect to make further contributions to our retirement plans and other postretirement benefit plans. However, EPCO maintains a 401(k) plan for the benefit of employees providing services to us, and we will continue to reimburse EPCO for the cost of maintaining this plan in accordance with the ASA.

NOTE 12. SEGMENT INFORMATION

We have three reporting segments:

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

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

Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. The two

largest operating expense items of the Downstream Segment are labor and electric power. We generally realize higher revenues during the first and fourth quarters of each year since our operations are somewhat seasonal. Refined products volumes are generally higher during the second and third quarters because of greater demand for gasolines during the spring and summer driving seasons. LPGs volumes are generally higher from November through March due to higher demand 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).

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 or delivery 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). Seaway consists of large diameter pipelines that transport crude oil from Seaway’s marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

Our Midstream Segment revenues are earned from the gathering of natural gas in the Green River Basin in southwestern Wyoming, through Jonah, and the gathering of coal bed methane and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde; transportation of NGLs from two trunkline NGL pipelines in South Texas, two NGL pipelines in East Texas and a pipeline system (Chaparral) from West Texas and New Mexico to Mont Belvieu; and the fractionation of NGLs in Colorado. Operating results of the Pioneer plant for the three months and six months ended June 30, 2006 and 2005 are shown as discontinued operations.

On April 1, 2006, we adopted EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (see Note 1), which resulted in crude oil inventory purchases and sales under buy/sell transactions, which were previously recorded as gross purchases and sales, to be treated as inventory exchanges in our consolidated statements of income. Implementation of EITF 04-13 as of April 1, 2006, reduced gross revenues and purchases for the three months ended June 30, 2006, but did not have a material effect on our financial position, results of operations or cash flows. Under the consensus reached in EITF 04-13, buy/sell transactions are reported as non-monetary exchanges and consequently not presented on a gross basis in our statements of income. Implementation of EITF 04-13 reduced revenues and purchases of petroleum products on our consolidated statements of income by approximately $313.7 million for the periods ended June 30, 2006. Under the provisions of the consensus, retroactive restatement of buy/sell transactions reported in prior periods was not permitted. The revenues and purchases of petroleum products associated with buy/sell transactions that are reported on a gross basis in our consolidated statements of income for the three months ended June 30, 2005, and for the six months ended June 30, 2006 and 2005, are approximately $326.9 million, $589.1 million and $403.3 million, respectively.

The table below includes financial information by reporting segment for the three months and six months ended June 30, 2006 and 2005 (in thousands):

	Three Months Ended June 30, 2006					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 2,273,878	$ 13,776	$ 2,287,654	$ (388)	$ 2,287,266
Operating revenues	69,333	13,134	56,569	139,036	(1,250)	137,786
Purchases of petroleum products	—	2,243,143	12,949	2,256,092	(1,336)	2,254,756
Operating expenses, including power	37,743	18,160	18,709	74,612	(302)	74,310
General and administrative expenses	4,701	1,870	2,587	9,158	—	9,158
Depreciation and amortization expense	10,133	3,494	15,049	28,676	—	28,676
Gains on sales of assets	(18)	—	—	(18)	—	(18)
Operating income	16,774	20,345	21,051	58,170	—	58,170
Equity earnings (losses)	(2,366)	5,040	—	2,674	—	2,674
Other income, net	185	225	44	454	—	454
Earnings before interest, deferred income taxes and discontinued operations	$ 14,593	$ 25,610	$ 21,095	$ 61,298	$ —	$ 61,298

	Three Months Ended June 30, 2005					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 1,961,302	$ —	$ 1,961,302	$ —	$ 1,961,302
Operating revenues	63,438	11,698	51,656	126,792	(709)	126,083
Purchases of petroleum products	—	1,942,599	—	1,942,599	(709)	1,941,890
Operating expenses, including power	35,171	13,995	10,342	59,508	—	59,508
General and administrative expenses	3,509	1,219	1,372	6,100	—	6,100
Depreciation and amortization expense	9,801	3,651	12,686	26,138	—	26,138
Gains on sales of assets	(15)	(53)	—	(68)	—	(68)
Operating income	14,972	11,589	27,256	53,817	—	53,817
Equity earnings (losses)	(246)	7,997	—	7,751	—	7,751
Other income, net	121	(46)	60	135	—	135
Earnings before interest, deferred income tax expense and discontinued operations	$ 14,847	$ 19,540	$ 27,316	$ 61,703	$ —	$ 61,703

	Six Months Ended June 30, 2006					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 4,674,314	$ 13,776	$ 4,688,090	$ (4,478)	$ 4,683,612
Operating revenues	143,400	24,280	112,946	280,626	(2,817)	277,809
Purchases of petroleum products	—	4,619,539	12,949	4,632,488	(6,692)	4,625,796
Operating expenses, including power	73,145	34,962	32,917	141,024	(603)	140,421
General and administrative expenses	9,795	3,677	4,887	18,359	—	18,359
Depreciation and amortization expense	20,430	6,765	30,238	57,433	—	57,433
Gains on sales of assets	(25)	—	(1,371)	(1,396)	—	(1,396)
Operating income	40,055	33,651	47,102	120,808	—	120,808
Equity earnings (losses)	(3,632)	7,295	—	3,663	—	3,663
Other income, net	964	269	120	1,353	—	1,353
Earnings before interest, deferred income tax expense and discontinued operations	$ 37,387	$ 41,215	$ 47,222	$ 125,824	$ —	$ 125,824

	Six Months Ended June 30, 2005					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 3,346,369	$ —	$ 3,346,369	$ —	$ 3,346,369
Operating revenues	141,605	23,411	101,840	266,856	(2,049)	264,807
Purchases of petroleum products	—	3,315,029	—	3,315,029	(2,049)	3,312,980
Operating expenses, including power	68,155	27,932	22,572	118,659	—	118,659
General and administrative expenses	7,711	2,727	2,867	13,305	—	13,305
Depreciation and amortization expense	19,362	7,152	25,235	51,749	—	51,749

Gains on sales of assets	(107)	(52)	(407)	(566)	—	(566)
Operating income	46,484	16,992	51,573	115,049	—	115,049
Equity earnings (losses)	(2,067)	13,912	—	11,845	—	11,845
Other income, net	270	29	102	401	—	401
Earnings before interest, deferred income tax expense and discontinued operations	$ 44,687	$ 30,933	$ 51,675	$ 127,295	$ —	$ 127,295

The following table includes total assets, capital expenditures, and significant non-cash investing activities for each segment as of and for the periods ended June 30, 2006, and December 31, 2005 (in thousands):

	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
June 30, 2006:						
Total assets	$ 1,059,421	$ 1,419,512	$ 1,227,797	$ 3,706,730	$ (19,595)	$ 3,687,135
Capital expenditures	27,273	22,223	32,955	82,451	12	82,463
December 31, 2005:						
Total assets	$ 1,056,217	$ 1,353,492	$ 1,280,548	$ 3,690,257	$ (9,719)	$ 3,680,538
Capital expenditures	58,609	40,954	119,837	219,400	1,153	220,553
Non-cash investing activities	1,429	—	—	1,429	—	1,429

The following table reconciles the segment data from the tables above to consolidated net income for the three months and six months ended June 30, 2006 and 2005 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Earnings before interest, deferred income tax expense and discontinued operations	$ 61,298	$ 61,703	$ 125,824	$ 127,295
Interest expense – net	(19,198)	(21,627)	(40,341)	(40,914)
Income before deferred income tax expense	42,100	40,076	85,483	86,381
Deferred income tax expense	514	—	514	—
Income from continuing operations	41,586	40,076	84,969	86,381
Discontinued operations	(122)	846	19,369	1,970
Net income	$ 41,464	$ 40,922	$ 104,338	$ 88,351

NOTE 13. COMMITMENTS AND CONTINGENCIES

Litigation

In the fall of 1999, the General Partner and TE Products were named as defendants in a lawsuit in Jackson County Circuit Court, Jackson County, Indiana, styled *Ryan E. McCleery and Marcia S. McCleery, et al. and Michael and Linda Robson, et al. v. Texas Eastern Corporation, et al.* In the lawsuit, 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 complaint, 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 March 18, 2005, we entered into Release and Settlement Agreements with the McCleery plaintiffs dismissing all of these plaintiffs' claims on terms that did not have a material adverse effect on our financial position, results of operations or cash flows. Although we did not settle with all plaintiffs and we therefore remain named parties in the *Michael and Linda Robson, et al. v. Texas Eastern Corporation, et al.* action, a co-defendant has agreed, by Cooperative Defense Agreement, to fund the defense and satisfy all final judgments which might be rendered with the 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 assert damages attributable to the remediation of the property of approximately $1.4 million; however, this case is covered by insurance, subject to applicable policy limits. 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. In response to the exception filed on behalf of the General Partner, the plaintiffs have agreed to voluntarily dismiss the General Partner from the suit. 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 1991, we were named as a defendant in a matter styled *Jimmy R. Green, et al. v. Cities Service Refinery, et al.* as filed in the 26th Judicial District Court of Bossier Parish, Louisiana. The plaintiffs in this matter reside or formerly resided on land that was once the site of a refinery owned by one of our co-defendants. The former refinery is located near our Bossier City facility. Plaintiffs have claimed personal injuries and property damage arising from alleged contamination of the refinery property. The plaintiffs have recently pursued certification as a class and have significantly increased their demand to approximately $175.0 million. This revised demand includes amounts for environmental restoration not previously claimed by the plaintiffs. We have never owned any interest in the refinery property made the basis of this action, and we do not believe that we contributed to any alleged contamination of this property. While we cannot predict the ultimate outcome, we do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

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

Regulatory Matters

Our processing and fractionation plants, pipelines, and associated facilities are subject to multiple environmental obligations and potential liabilities under a variety of federal, state and local laws and regulations. These include, without limitation: the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Clean Air Act; the Federal Water Pollution Control Act or the Clean Water Act; the Oil Pollution Act; and analogous state and local laws and regulations. Such laws and

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regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges, and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could influence our results of operations. If an accidental leak, spill or release of hazardous substances occurs at any facilities that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held jointly and severally liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. Any or all of this could materially affect our results of operations and cash flows.

We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations, and that the cost of compliance with such laws and regulations will not have a material adverse effect on our results of operations or financial position. We cannot ensure, however, that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows. At June 30, 2006, and December 31, 2005, we have an accrued liability of $2.1 million and $2.4 million, respectively, related to sites requiring environmental remediation activities.

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 June 30, 2006, 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 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, as well as three smaller spills at other locations in 2004 and 2005. We have agreed with the DOJ on a proposed penalty of $2.865 million, along with our commitment to implement additional spill prevention measures, and expect to finalize the settlement in the third quarter of 2006. We do not expect this settlement to have a material adverse effect on our financial position, results of operations or cash flows.

One of the spills encompassed in our current settlement discussion with the DOJ involved a 37,450-gallon release from Seaway on May 13, 2005 at Colbert, Oklahoma. This release was remediated under the supervision of the Oklahoma Corporation Commission, but has resulted in claims by neighboring landowners, for which we anticipate a financial settlement in the range of $0.7 million to $0.8 million. In addition, the release resulted in a Corrective Action Order by the U.S. Department of Transportation. Among other requirements of this Order, we were required to reduce the operating pressure of Seaway by 20% until completion of required corrective actions. The corrective actions were completed and on June 1, 2006, we increased the operating pressure of Seaway back to

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100%. We have a 50% ownership interest in Seaway, and any settlement should be covered by our insurance. We do not expect the completion of our obligations relating to the Colbert release to have a material adverse effect on our financial position, results of operations or cash flows.

On September 18, 2005, a propane release and fire occurred at our Todhunter facility, near Middletown, Ohio. The incident resulted in the death of one of our employees; there were no other injuries. Repairs to the impacted facilities have been completed. On March 17, 2006, we received a citation from the Occupational Safety and Health Administration ("OSHA") arising out of this incident, with a proposed penalty of $0.1 million. We are currently in settlement discussions with OSHA. We do not expect that any settlement of this citation will have a material adverse effect on our financial position, results of operations or cash flows.

We are also in negotiations with the U.S. Department of Transportation with respect to a notice of probable violation that we received on April 25, 2005, for alleged violations of pipeline safety regulations at our Todhunter facility, with a proposed $0.4 million civil penalty. We responded on June 30, 2005, by admitting certain of the alleged violations, contesting others and requesting a reduction in the proposed civil penalty. We do not expect any settlement, fine or penalty to have a material adverse effect on our financial position, results of operations or cash flows.

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

On July 20, 2004, the District of Columbia Circuit issued an opinion in *BP West Coast Products LLC v. FERC*. In reviewing a series of orders involving SFPP, L.P., the court held among other things that the FERC had not adequately justified its policy of providing an oil pipeline limited partnership with an income tax allowance equal to the proportion of its income attributable to partnership interests owned by corporate partners. Under the FERC's initial ruling, SFPP, L.P. was permitted an income tax allowance on its cost-of-service filing for the percentage of its net operating (pre-tax) income attributable to partnership units held by corporations, and was denied an income tax allowance equal to the percentage attributable to partnership units held by non-corporate partners. The court remanded the case back to the FERC for further review. Following the court's remand, on May 4, 2005, the FERC issued its Policy Statement on Income Tax Allowances, which permits regulated partnerships, limited liability companies and other pass-through entities an income tax allowance on their income attributable to any owner that has an actual or potential income tax liability on that income, regardless whether the owner is an individual or corporation. If there is more than one level of pass-through entities, the regulated company income must be traced to where the ultimate tax liability lies. The Policy Statement is to be applied in individual cases, and the regulated entity bears the burden of proof to establish the tax status of its owners. On December 16, 2005, the FERC issued the first of those decisions, in an order involving SFPP (the "SFPP Order"). The SFPP Order confirmed that a master limited partnership is entitled to a tax allowance with respect to partnership income for which there is an "actual or potential income tax liability" and determined that a unitholder that is required to file a Form 1040 or

Form 1120 tax return that includes partnership income or loss is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income. The FERC also established certain other presumptions, including that corporate unitholders are presumed to be taxed at the maximum corporate tax rate of 35% while individual unitholders (and certain other types of unitholders taxed like individuals) are presumed to be taxed at a 28% tax rate. The SFPP Order remains subject to further administrative proceedings, including review by the FERC of compliance filings made by SFPP on March 7, 2006, as well as judicial review. The ultimate outcome of the FERC's inquiry on income tax allowance should not affect our current rates and rate structure because our rates are not based on cost-of-service methodology. However, the outcome of the income tax allowance would become relevant to us should we (i) elect in the future to use cost-of-service to support our rates, or (ii) be required to use such methodology to defend our indexed rates.

Other

Centennial entered into credit facilities totaling $150.0 million, and as of June 30, 2006, $150.0 million was outstanding under those credit facilities, of which $140.0 million expires in 2024, and $10.0 million expires in April 2007. TE Products and Marathon have each guaranteed one-half of the repayment of Centennial's outstanding debt balance (plus interest) under these credit facilities. The guarantees arose in order for Centennial to obtain adequate financing, and the proceeds of the credit facilities were used to fund construction and conversion costs of its pipeline system. Prior to the expiration of the long-term credit facility, 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 June 30, 2006.

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 $4.5 million obligation, which represents the present value of the estimated amount that we would have to pay under the guarantee. If a catastrophic event were to occur and we were required to contribute cash to Centennial, contributions exceeding our deductible might be covered by our insurance.

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

On February 24, 2005, the General Partner was acquired from DEFS by DFI. The General Partner owns a 2% general partner interest in us and is the general partner of the Partnership. On March 11, 2005, the Bureau of Competition of the Federal Trade Commission ("FTC") delivered written notice to DFI's legal advisor that it was conducting a non-public investigation to determine whether DFI's acquisition of our General Partner may substantially lessen competition or violate other provisions of federal antitrust laws. We and our General Partner have cooperated fully with this investigation. In order to resolve the matter, we and our General Partner have negotiated with the staff of the FTC and agreed to a proposal that, if accepted by the FTC, would require the divestiture of our 50% ownership interest in MB Storage and certain related assets.

NOTE 14. 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 six months ended June 30, 2006, the components of accumulated other comprehensive income reflected on our consolidated balance sheets were composed of crude oil hedges and interest rate swaps. The crude oil hedges mature in December 2006 and December 2007. While the crude oil hedges are in effect, changes in their fair values, to the extent the hedges are effective, are recognized in accumulated other comprehensive income until they are recognized in net income in future periods. The interest rate swaps mature in January 2008, are related to our variable rate revolving credit facility and are designated as cash flow hedges beginning in the third quarter of 2006.

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

Balance at December 31, 2005	$ 11
Changes in fair values of interest rate cash flow hedges	1,671
Changes in fair values of interest rate cash flow hedges	(1,671)
Changes in fair values of crude oil cash flow hedges	(273)
Balance at June 30, 2006	$ (262)

NOTE 15. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

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 guarantees of our debt securities. The guarantees are full, unconditional, and joint and several. These significant 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., are collectively referred to as the "Guarantor Subsidiaries." The guarantees issued by Jonah Gas Gathering Company, which were outstanding during the periods presented below, were released on July 31, 2006, in connection with the joint venture entered into with Enterprise on that date (see Note 16).

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.

	June 30, 2006				
	TEPPCO Partners, L .P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 42,291	$ 76,978	$ 861,110	$ (51,567)	$ 928,812
Property, plant and equipment – net	—	1,316,037	641,414	—	1,957,451
Equity investments	1,171,941	462,165	201,626	(1,482,213)	353,519
Intercompany notes receivable	1,171,699	—	—	(1,171,699)	—
Intangible assets	—	330,014	30,586	—	360,600
Other assets	5,038	23,172	58,543	—	86,753
Total assets	$ 2,390,969	$ 2,208,366	$ 1,793,279	$ (2,705,479)	$ 3,687,135
Liabilities and partners' capital					
Current liabilities	$ 44,617	$ 102,430	$ 842,808	$ (53,794)	$ 936,061
Long-term debt	1,173,053	378,624	—	—	1,551,677
Intercompany notes payable	—	640,624	531,076	(1,171,700)	—
Other long term liabilities	1,387	25,457	903	—	27,747
Total partners' capital	1,171,912	1,061,231	418,492	(1,479,985)	1,171,650
Total liabilities and partners' capital	$ 2,390,969	$ 2,208,366	$ 1,793,279	$ (2,705,479)	$ 3,687,135

	December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 40,977	$ 107,692	$ 789,486	$ (39,026)	$ 899,129
Property, plant and equipment – net	—	1,335,724	624,344	—	1,960,068
Equity investments	1,201,388	461,741	202,343	(1,505,816)	359,656
Intercompany notes receivable	1,134,093	—	—	(1,134,093)	—
Intangible assets	—	345,005	31,903	—	376,908

Other assets	5,532	22,170	57,075	—	84,777
Total assets	$ 2,381,990	$ 2,272,332	$ 1,705,151	$ (2,678,935)	$ 3,680,538
Liabilities and partners' capital					
Current liabilities	$ 43,236	$ 140,743	$ 793,683	$ (40,451)	$ 937,211
Long-term debt	1,135,973	389,048	—	—	1,525,021
Intercompany notes payable	—	635,263	498,832	(1,134,095)	—
Other long term liabilities	1,422	14,564	950	—	16,936
Total partners' capital	1,201,359	1,092,714	411,686	(1,504,389)	1,201,370
Total liabilities and partners' capital	$ 2,381,990	$ 2,272,332	$ 1,705,151	$ (2,678,935)	$ 3,680,538

	Three Months Ended June 30, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 109,775	$ 2,317,678	$ (2,401)	$ 2,425,052
Costs and expenses	—	81,190	2,288,111	(2,401)	2,366,900
Gains on sales of assets	—	(18)	—	—	(18)
Operating income	—	28,603	29,567	—	58,170
Interest expense – net	—	(13,504)	(5,694)	—	(19,198)
Equity earnings	41,464	26,783	5,040	(70,613)	2,674
Other income – net	—	202	252	—	454
Income before deferred income tax expense	41,464	42,084	29,165	(70,613)	42,100
Deferred income tax expense	—	498	16	—	514
Income from continuing operations	41,464	41,586	29,149	(70,613)	41,586
Discontinued operations	—	(122)	—	—	(122)
Net income	$ 41,464	$ 41,464	$ 29,149	$ (70,613)	$ 41,464

	Three Months Ended June 30, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 100,662	$ 1,987,432	$ (709)	$ 2,087,385
Costs and expenses	—	67,120	1,967,225	(709)	2,033,636
Gains on sales of assets	—	(15)	(53)	—	(68)
Operating income	—	33,557	20,260	—	53,817
Interest expense – net	—	(14,257)	(7,370)	—	(21,627)
Equity earnings	40,922	20,614	7,997	(61,782)	7,751
Other income – net	—	162	(27)	—	135
Income from continuing operations	40,922	40,076	20,860	(61,782)	40,076
Discontinued operations	—	846	—	—	846
Net income	$ 40,922	$ 40,922	$ 20,860	$ (61,782)	$ 40,922

	Six Months Ended June 30, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 224,835	$ 4,744,644	$ (8,058)	$ 4,961,421
Costs and expenses	—	156,953	4,693,114	(8,058)	4,842,009
Gains on sales of assets	—	(1,396)	—	—	(1,396)
Operating income	—	69,278	51,530	—	120,808
Interest expense – net	—	(27,881)	(12,460)	—	(40,341)
Equity earnings	104,338	43,045	7,295	(151,015)	3,663
Other income – net	—	1,025	328	—	1,353
Income before deferred income tax expense	104,338	85,467	46,693	(151,015)	85,483
Deferred income tax expense	—	498	16	—	514
Income from continuing operations	104,338	84,969	46,677	(151,015)	84,969
Discontinued operations	—	19,369	—	—	19,369
Net income	$ 104,338	$ 104,338	$ 46,677	$ (151,015)	$ 104,338

	Six Months Ended June 30, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		

Operating revenues	$ —	$ 215,773	$ 3,397,452	$ (2,049)	$ 3,611,176
Costs and expenses	—	133,209	3,365,533	(2,049)	3,496,693
Gains on sales of assets	—	(514)	(52)	—	(566)
Operating income	—	83,078	31,971	—	115,049
Interest expense – net	—	(27,275)	(13,639)	—	(40,914)
Equity earnings	88,351	30,233	13,912	(120,651)	11,845
Other income – net	—	345	56	—	401
Income from continuing operations	88,351	86,381	32,300	(120,651)	86,381
Discontinued operations	—	1,970	—	—	1,970
Net income	$ 88,351	$ 88,351	$ 32,300	$ (120,651)	$ 88,351

	Six Months Ended June 30, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Cash flows from operating activities					
Net income	$ 104,338	$ 104,338	$ 46,677	$ (151,015)	$ 104,338
Adjustments to reconcile net income to net cash provided by continuing operating activities:					
Income from discontinued operations	—	(19,369)	—	—	(19,369)
Deferred income tax expense	—	498	16	—	514
Depreciation and amortization	—	45,114	12,319	—	57,433
Earnings in equity investments, net of distributions	29,447	3,591	1,162	(21,566)	12,634
Gains on sales of assets	—	(1,396)	—	—	(1,396)
Changes in assets and liabilities and other	(31,902)	11,640	(18,034)	25,676	(12,620)
Net cash provided by continuing operating activities	101,883	144,416	42,140	(146,905)	141,534
Cash flows from discontinued operations	—	1,521	—	—	1,521
Net cash provided by operating activities	101,883	145,937	42,140	(146,905)	143,055
Cash flows from investing activities	—	85,290	(29,960)	(103,634)	(48,304)
Cash flows from financing activities	(94,685)	(231,289)	(12,051)	243,340	(94,685)
Net increase (decrease) in cash and cash equivalents	7,198	(62)	129	(7,199)	66
Cash and cash equivalents at beginning of period	1,978	62	45	(1,966)	119
Cash and cash equivalents at end of period	$ 9,176	$ —	$ 174	$ (9,165)	$ 185

	Six Months Ended June 30, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (in thousands)	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Cash flows from operating activities					
Net income	$ 88,351	$ 88,351	$ 32,300	$ (120,651)	$ 88,351
Adjustments to reconcile net income to net cash provided by (used in) continuing operating activities:					
Income from discontinued operations	—	(1,970)	—	—	(1,970)
Depreciation and amortization	—	39,514	12,235	—	51,749
Earnings (losses) in equity investments, net of distributions	28,965	731	(2,165)	(20,329)	7,202
Gains on sales of assets	—	(514)	(52)	—	(566)
Changes in assets and liabilities and other	74,856	(29,979)	(85,699)	(76,242)	(117,064)
Net cash provided by continuing operating activities	192,172	96,133	(43,381)	(217,222)	27,702
Cash flows from discontinued operations	—	2,251	—	—	2,251
Net cash provided by (used in) operating activities	192,172	98,384	(43,381)	(217,222)	29,953
Cash flows from investing activities	(278,832)	(2,606)	(67,447)	217,488	(131,397)
Cash flows from financing activities	86,516	(108,122)	108,244	(122)	86,516
Net increase (decrease) in cash and cash equivalents	(144)	(12,344)	(2,584)	144	(14,928)
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	$ 3,972	$ 1,252	$ 242	$ (3,972)	$ 1,494

NOTE 16. SUBSEQUENT EVENTS

In July 2006, we issued and sold in an underwritten public offering 5.0 million Units at a price to the public of $35.50 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $170.4 million. On July 12, 2006, 750,000 additional Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering. Proceeds from the over-allotment sale, net of underwriting discount, totaled $25.6 million. The net proceeds from the offering and the over-allotment were used to reduce indebtedness under our Revolving Credit Facility.

On July 31, 2006, we executed a third amendment ("Third Amendment") to our Revolving Credit Facility which extends the maturity date of amounts borrowed under the Revolving Credit Facility from December 2010 to December 2011. The Third Amendment also releases Jonah as a guarantor of the Revolving Credit Facility. The Third Amendment restricts the amount of outstanding debt of the Jonah joint venture to debt owing to the owners of its partnership interests and other debt in the principal aggregate amount of $50.0 million. In addition, the Third Amendment allows for swing line loans up to $25.0 million (within the $700.0 million total borrowing limit) and modifies our financial covenants to, among other things, allow us to include in the calculation of our Consolidated EBITDA (as defined in the Revolving Credit Facility, as amended) pro forma adjustments for material projects.

Effective July 31, 2006, Jonah Gas Gathering Company was also released from its guarantee to Wachovia Bank pursuant to the provisions of Section 14.04 dated as of February 20, 2002, of the Indenture between us, as issuer, TE Products, TCTM, TEPPCO Midstream and Jonah Gas Gathering Company, each as subsidiary guarantors and Wachovia Bank, as trustee.

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. 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 Current Report on Form 8-K filed on June 16, 2006, which recast certain information from our Annual Report on Form 10-K for the year ended December 31, 2005, as discontinued operations. Our discussion and analysis includes the following:

- Cautionary Note Regarding Forward-Looking Statements.
- Overview of Critical Accounting Policies and Estimates.
- Overview of Business.
- Results of Operations – Discusses material period-to-period variances in the consolidated statements of income.
- Financial Condition and Liquidity – Analyzes cash flows and financial position.
- Other Considerations – Addresses available sources of liquidity, trends, future plans and contingencies that are reasonably likely to materially affect future liquidity or earnings.
- Recent Accounting Pronouncements.

Cautionary Note Regarding Forward-Looking Statements

The matters discussed in this Quarterly Report on Form 10-Q (this "Report") include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements that express belief, expectation, estimates or intentions, as well as those that are not statements of historical facts are forward-looking statements. The words "proposed", "anticipate", "potential", "may", "will", "could", "should", "expect", "estimate", "believe", "intend", "plan", "seek" and similar expressions are intended to identify forward-looking statements. Without limiting the broader description of forward-looking statements above, 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 future distributions, 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

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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. Also note that we provide a cautionary discussion of risks and uncertainties under the caption "Risk Factors" and elsewhere in this Form 10-Q; under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Current Report on Form 8-K filed on June 16, 2006; and in our Annual Report on Form 10-K for the year ended December 31, 2005.

The forward-looking statements contained in this Report speak only as of the date hereof. Except as required by the federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason. All forward-looking statements attributable to TEPPCO Partners, L.P. or any person acting on its behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this Quarterly Report on Form 10-Q and in our future periodic reports filed with the Securities and Exchange Commission ("SEC"). In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Report may not occur. For additional discussion of such risks and uncertainties, see our Annual Report on Form 10-K for the year ended December 31, 2005, and other filings we have made with the SEC.

Overview of 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 included in our Annual Report on Form 10-K for the year ended December 31, 2005, and in our Current Report on Form 8-K filed on June 16, 2006. Certain of these accounting policies require the use of estimates. As more fully described therein, 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 position and results of operations.

Overview of Business

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

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

- Our Downstream Segment, which is engaged in the transportation and storage of refined products, liquefied petroleum products ("LPGs") and petrochemicals;

- Our Upstream Segment, which is engaged in the gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals; and
- Our Midstream Segment, which is engaged in the gathering of natural gas, transportation of natural gas liquids ("NGLs") and fractionation of NGLs.

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

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

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

We continue to build a base for long-term growth by pursuing new business opportunities, increasing throughput on our pipeline systems, constructing new pipeline and gathering systems, and expanding and upgrading our existing infrastructure. We remain confident that our business strategy will provide continued growth in earnings and cash distributions. We believe the following factors are important to our growth potential:

- Continued development and expansion of the Jonah system which serves the Jonah and Pinedale fields in our Midstream Segment. Through additional Jonah expansions, which should be completed in the fourth quarter of 2007, we expect to increase the capacity to 2.4 billion cubic feet per day.
- Expanding our Downstream Segment gathering capacity of refined products along the upper Texas Gulf Coast.
- Utilizing available Downstream Segment system capacity of Centennial to move refined products to Midwest market areas, which enables us to increase movements of long-haul propane volumes.
- Expanding our Downstream Segment system delivery capability of gasoline and diesel fuel in the Indianapolis and Chicago market areas.
- Continued integration of 2005 acquisitions by our Upstream Segment into our existing asset base.
- Expanding our West Texas system and storage capacity at Cushing in our Upstream Segment.

- Adding new volumes and improving the operating efficiency of the Val Verde system in our Midstream Segment in New Mexico's San Juan Basin, through new connections of conventional and Colorado coal seam gas.
- Increasing throughput on our Midstream Segment NGL systems.
- Pursuing acquisitions or organic growth projects in any of our business segments that would complement our current operations.

For additional discussion of important factors that could affect our growth, please read "-Cautionary Note Regarding Forward-Looking Statements" and "Risk Factors" in this Report.

Our Upstream Segment's performance for 2006 will be impacted by a decrease in our participation ratio in the revenue and expense of Seaway, in accordance with the Seaway Crude Pipeline Company Partnership Agreement. From June 2002 through May 2006, we receive 60% of revenue and expense of Seaway. Thereafter, we will receive 40% of revenue and expense of Seaway. Our share of revenue and expense of Seaway is 47% for 2006 (see Note 7 in the Notes to the Consolidated Financial Statements).

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.

Jonah Joint Venture

We expect to further expand the Jonah system. On August 1, 2006, Enterprise Products Partners L.P. ("Enterprise") (through an affiliate) became our joint venture partner by acquiring an interest in our Jonah Gas Gathering Company, the partnership through which we owned the Jonah system. Prior to entering into the joint venture, Enterprise had managed the construction of the Phase V expansion and funded the initial costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and Enterprise intend to continue the Phase V expansion, which is expected to increase the system capacity of the Jonah system from 1.5 billion cubic feet per day ("Bcf/d") to approximately 2.4 Bcf/d and to significantly reduce system operating pressures, which is anticipated to lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is expected to increase the system gathering capacity to approximately 2.0 Bcf/d, is scheduled to be completed in the first quarter of 2007 at an estimated cost of approximately $275.0 million. The second portion of the expansion is expected to cost approximately $140.0 million and be completed by the end of 2007.

Enterprise will continue to manage the Phase V construction project. We are entitled to all distributions from the joint venture until specified milestones are achieved, at which point, Enterprise will be entitled to receive 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. After subsequent milestones are achieved, we and Enterprise will share distributions based on a formula that takes into account the capital contributions of the parties, including expenditures by us prior to the expansion. In the third quarter of 2006, we will reimburse Enterprise for 50% of the Phase V cost incurred by it through August 1, 2006 (including its cost of capital). From August 1, 2006, we and Enterprise equally share the costs of the Phase V expansion. Upon completion of the expansion project and based on the formula in the partnership agreement, we expect to own an interest in Jonah Gas Gathering Company of approximately 80%, with Enterprise owning the remaining 20% and serving as operator and with further costs being allocated based on such ownership interests. The joint venture will be governed by a management committee comprised of two representatives approved by Enterprise and two representatives approved by us, each with equal voting power. This transaction was reviewed and approved by the Audit and Conflicts Committee of the board of directors of our General Partner. Through June 30, 2006, Enterprise had incurred approximately $106.9 million of costs related to the expansion, of which $97.8 million has been paid to vendors by Enterprise.

EPCO Proposal

On April 20, 2006, EPCO submitted a proposal to the Audit and Conflicts Committee of our General Partner's Board of Directors to reduce the General Partner's maximum percentage interest in our quarterly distributions from 50% to 25% with respect to that portion of our quarterly cash distribution to partners that exceeds $0.325 per Unit. In exchange for the agreement to reduce its maximum percentage interest in our quarterly distributions, our General Partner would receive a number of newly-issued Units that, based on the distribution rate and the number of Units outstanding at the time of issuance, would result in our General Partner receiving cash distributions from the newly issued Units and from its reduced maximum percentage interest in our quarterly distributions that would approximately equal the cash distributions our General Partner would have received from its maximum percentage interest in our quarterly distributions without reduction. Based on our distribution rate and outstanding Units as of the date of the filing of this Report, the number of newly-issued Units issued to the General Partner would be approximately 14.1 million. We filed with the Securities and Exchange

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Commission a preliminary proxy statement that outlines the EPCO proposal for which we will solicit approval from our unitholders at a special meeting. The proxy statement also contains separate proposals for the adoption of an employee Unit purchase plan and a long term incentive plan.

Results of Operations

The following table summarizes financial information by business segment for the three months and six months ended June 30, 2006 and 2005 (in thousands):

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Operating revenues:				
Downstream Segment	$ 69,333	$ 63,438	$ 143,400	$ 141,605
Upstream Segment	2,287,012	1,973,000	4,698,594	3,369,780
Midstream Segment	70,345	51,656	126,722	101,840
Intersegment eliminations	(1,638)	(709)	(7,295)	(2,049)
Total operating revenues	2,425,052	2,087,385	4,961,421	3,611,176
Operating income:				
Downstream Segment	16,774	14,972	40,055	46,484
Upstream Segment	20,345	11,589	33,651	16,992
Midstream Segment	21,051	27,256	47,102	51,573
Total operating income	58,170	53,817	120,808	115,049
Earnings before interest:				
Downstream Segment	14,593	14,847	37,387	44,687
Upstream Segment	25,610	19,540	41,215	30,933
Midstream Segment	21,095	27,316	47,222	51,675
Interest expense	(22,356)	(22,780)	(46,758)	(43,169)
Interest capitalized	3,158	1,153	6,417	2,255
Income before deferred income tax expense	42,100	40,076	85,483	86,381
Deferred income tax expense	514	—	514	—
Income from continuing operations	41,586	40,076	84,969	86,381
Discontinued operations	(122)	846	19,369	1,970
Net income	$ 41,464	$ 40,922	$ 104,338	$ 88,351

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 six months ended June 30, 2006 and 2005 (in thousands):

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Increase (Decrease)	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005	Increase (Decrease)
Revenues:						
Transportation – Refined products	$ 39,443	$ 37,834	$ 1,609	$ 71,242	$ 72,799	$ (1,557)
Transportation – LPGs	13,354	14,470	(1,116)	42,775	46,701	(3,926)
Other	16,536	11,134	5,402	29,383	22,105	7,278
Total operating revenues	69,333	63,438	5,895	143,400	141,605	1,795
Costs and expenses:						
Operating expense	26,305	24,772	1,533	49,807	47,185	2,622
Operating fuel and power	8,318	7,957	361	17,623	15,617	2,006
General and administrative	4,701	3,509	1,192	9,795	7,711	2,084
Depreciation and amortization	10,133	9,801	332	20,430	19,362	1,068
Taxes – other than income taxes	3,120	2,442	678	5,715	5,353	362
Gains on sales of assets	(18)	(15)	(3)	(25)	(107)	82
Total costs and expenses	52,559	48,466	4,093	103,345	95,121	8,224
Operating income	16,774	14,972	1,802	40,055	46,484	(6,429)
Equity losses	(2,366)	(246)	(2,120)	(3,632)	(2,067)	(1,565)
Other income – net	185	121	64	964	270	694
Earnings before interest	$ 14,593	$ 14,847	$ (254)	$ 37,387	$ 44,687	$ (7,300)

The following table presents volumes delivered in barrels and average tariff per barrel for the three months and six months ended June 30, 2006 and 2005 (in thousands, except tariff information):

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Percentage Increase (Decrease)	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005	Percentage Increase (Decrease)

Volumes Delivered:						
Refined products	46,049	42,097	9%	81,857	80,692	1%
LPGs	8,277	7,855	5%	21,117	22,657	(7)%
Total	54,326	49,952	9%	102,974	103,349	—
Average Tariff per Barrel:						
Refined products	$ 0.86	$ 0.90	(4)%	$ 0.87	$ 0.90	(3)%
LPGs	1.33	1.84	(28)%	1.91	2.06	(7)%
Average system tariff per barrel	0.93	1.05	(11)%	1.08	1.16	(7)%

Three Months Ended June 30, 2006 Compared with Three Months Ended June 30, 2005

Revenues from refined products transportation increased $1.6 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005, primarily due to an overall increase of 9% in the refined products volumes delivered. Volume increases were due to increased demand for products supplied from the U.S. Gulf Coast into Midwest markets resulting from higher distillate price differentials and a greater demand for gasoline. Refined products revenues were also impacted by a strong demand for gasoline blendstocks, partially offset by lower average tariff jet fuel volumes during the three months ended June 30, 2006, compared with the three months ended June 30, 2005. In February 2003, we entered into a lease agreement with Centennial that increased our flexibility to deliver refined products to our market areas. As a result, Centennial has provided our system with

additional pipeline capacity for movement of products originating in the U.S. Gulf Coast area. Prior to the construction of Centennial, deliveries on our pipeline system were limited by our pipeline capacity, and transportation services for our customers were allocated in accordance with a proration policy. The Centennial capacity lease has relieved our previously constrained system and has permitted expanded deliveries in markets both south and north of Creal Springs, Illinois. Movement of TEPPCO product via the Centennial lease to the north end of our system permits expanded supply capability of the TEPPCO system for delivery to the south end of our system. Movements of refined products on Centennial has resulted in a decrease in the refined products average rate per barrel; however, utilizing Centennial for refined products movements allows us to increase movements of long-haul propane volumes.

Revenues from LPGs transportation decreased $1.1 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005, due to lower deliveries of propane in the upper Midwest and Northeast market areas as a result of high propane prices delaying summer fill programs and scheduled maintenance, known as a turnaround, on a mid-continent petrochemical plant. Additionally, revenues decreased due to lower isobutane deliveries resulting from a Midwest refinery turnaround. The LPGs average rate per barrel decreased from the prior period primarily as a result of increased short-haul deliveries during the three months ended June 30, 2006, compared with the three months ended June 30, 2005.

Other operating revenues increased $5.4 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005, primarily due to increased volumes of product sales, higher storage revenues on assets acquired from Texas Genco, LLC in July 2005 and higher refined products tender deduction revenue.

Costs and expenses increased $4.1 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005. Operating expenses increased $1.5 million primarily due to a $2.0 million increase in pipeline operating costs primarily as a result of acquisitions made in 2005, $1.0 million of higher insurance premiums, a $0.7 million regulatory penalty for past incidents, $0.6 million in severance expense resulting from the migration to a shared services environment with EPCO and $0.4 million of expenses relating to the proposed reduction in the General Partner's maximum percentage interest in our distributions (see Note 9 in the Notes to the Consolidated Financial Statements). These increases in operating expenses were partially offset by $1.8 million in product measurement gains and a $1.0 million decrease in pipeline inspection and repair costs associated with our integrity management program. General and administrative expenses increased $1.2 million primarily due to severance expense resulting from the migration to a shared services environment with EPCO and other executive compensation expense. Taxes — other than income taxes increased $0.7 million primarily due to a higher property asset base. Operating fuel and power increased $0.4 million primarily due to increased mainline throughput and higher power rates. Depreciation and amortization expense increased $0.3 million primarily due to the recording of a conditional asset retirement obligation, as discussed below.

Net losses from equity investments increased for the three months ended June 30, 2006, compared with the three months ended June 30, 2005, as shown below (in thousands):

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Increase (Decrease)
Centennial	$ (3,401)	$ (1,634)	$ (1,767)
MB Storage	1,043	1,365	(322)
Other	(8)	23	(31)
Total equity losses	$ (2,366)	$ (246)	$ (2,120)

Equity losses in Centennial increased $1.8 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005, primarily due to lower transportation revenues and increased costs relating to pipeline inspection and repair costs associated with its integrity management program, partially offset by lower amortization expense on the portion of TE Products' excess investment in Centennial resulting from slightly lower

volumes. Equity earnings in MB Storage decreased $0.3 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005, primarily due to higher system maintenance expenses on the MB Storage system and higher general and administrative expenses, partially offset by higher revenues.

Six Months Ended June 30, 2006 Compared with Six Months Ended June 30, 2005

Revenues from refined products transportation decreased $1.6 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, primarily due to a decrease in the average rate per barrel, partially offset by a 1% increase in the refined products volumes delivered. Volume increases were due to increased demand for products supplied from the U.S. Gulf Coast into Midwest markets resulting from higher distillate price differentials and a greater demand for gasoline. Refined products volumes were also impacted by unfavorable differentials for motor fuels and distillate during the first quarter of 2006. Movements of refined products on Centennial has resulted in a decrease in the refined products average rate per barrel; however, utilizing Centennial for refined products movements allows us to increase movements of long-haul propane volumes.

Revenues from LPGs transportation decreased $3.9 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, due to lower deliveries of propane in the upper Midwest and Northeast market areas as a result of warmer than normal winter weather, high propane prices and plant turnarounds. The LPGs average rate per barrel decreased from the prior period primarily as a result of increased short-haul deliveries during the six months ended June 30, 2006, compared with the six months ended June 30, 2005.

Other operating revenues increased $7.3 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, primarily due to increased volumes of product sales, higher storage revenues on assets acquired from Texas Genco, LLC in July 2005 and higher refined products tender deduction revenue.

Costs and expenses increased $8.3 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005. Operating expense increased $2.6 million primarily due to a $3.8 million increase in pipeline operating costs primarily as a result of acquisitions made in 2005, $1.5 million of higher insurance premiums, $0.6 million in severance expense as a result of the migration to a shared services environment with EPCO, $0.4 million of expenses relating to the proposed reduction in the General Partner’s maximum percentage interest in our distributions (see Note 9 in the Notes to the Consolidated Financial Statements) and increases related to regulatory penalties for past incidents, environmental remediation and assessments costs and transition costs. These increases in costs and expenses were partially offset by a $3.0 million decrease in pipeline inspection and repair costs associated with our integrity management program, $1.5 million in product measurement gains and a $0.7 million decrease in rental expense from the Centennial pipeline capacity lease agreement. General and administrative expenses increased $2.1 million primarily due to a $1.1 million increase relating to the retirement of an executive in February 2006 and $0.6 million in severance expense as a result of the migration to a shared services environment with EPCO and higher other executive compensation expense. Operating fuel and power increased $2.0 million primarily due to increased mainline throughput and higher power rates. Depreciation expense increased $1.1 million primarily due to assets placed into service, asset retirements in 2006 and the recording of a conditional asset retirement obligation as discussed below. Taxes – other than income taxes increased $0.4 million primarily due to a higher property asset base in the 2006 period.

Net losses from equity investments increased for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, as shown below (in thousands):

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005	Increase (Decrease)
Centennial	$ (7,313)	$ (6,084)	$ (1,229)
MB Storage	3,692	3,998	(306)
Other	(11)	19	(30)
Total equity losses	$ (3,632)	$ (2,067)	$ (1,565)

Equity losses in Centennial increased $1.2 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, primarily due to lower transportation revenues and volumes primarily due to warmer than normal winter weather in the Northeast and increased costs relating to pipeline inspection and repair costs associated with its integrity management program. Equity earnings in MB Storage decreased $0.3 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, primarily due to higher system maintenance expenses and higher general and administrative expenses, partially offset by higher revenues.

Other income – net increased $0.7 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, due to higher interest income earned on cash investments and other investing activities.

Asset Retirement Obligations

During the second quarter of 2006, we recorded $0.3 million of expense, included in depreciation and amortization expense, related to a conditional asset retirement obligation. Additionally, we recorded a $0.4 million liability, which represents the fair value, as measured at June 30, 2006, of the conditional asset retirement obligation related to structural restoration work to be completed on leased office space that is required upon our anticipated office lease termination (see Note 1 in the Notes to the Consolidated Financial Statements).

Upstream Segment

The following table provides financial information for the Upstream Segment for the three months and six months ended June 30, 2006 and 2005 (in thousands):

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Increase (Decrease)	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005	Increase (Decrease)
Revenues:						

	Three Months 2006	Three Months 2005	Increase (Decrease)	Six Months 2006	Six Months 2005	Increase (Decrease)
Sales of petroleum products	$ 2,273,878	$ 1,961,302	$ 312,576	$ 4,674,314	$ 3,346,369	$ 1,327,945
Transportation – Crude oil	10,544	9,042	1,502	19,467	18,214	1,253
Other	2,590	2,656	(66)	4,813	5,197	(384)
Total operating revenues	2,287,012	1,973,000	314,012	4,698,594	3,369,780	1,328,814
Costs and expenses:						
Purchases of petroleum products	2,243,143	1,942,599	300,544	4,619,539	3,315,029	1,304,510
Operating expense	14,837	11,693	3,144	27,981	23,001	4,980
Operating fuel and power	1,766	1,234	532	3,959	2,462	1,497
General and administrative	1,870	1,219	651	3,677	2,727	950
Depreciation and amortization	3,494	3,651	(157)	6,765	7,152	(387)
Taxes – other than income taxes.	1,557	1,068	489	3,022	2,469	553
Gains on sales of assets	—	(53)	53	—	(52)	52
Total costs and expenses	2,266,667	1,961,411	305,256	4,664,943	3,352,788	1,312,155
Operating income	20,345	11,589	8,756	33,651	16,992	16,659
Equity earnings	5,040	7,997	(2,957)	7,295	13,912	(6,617)
Other income – net	225	(46)	271	269	29	240
Earnings before interest	$ 25,610	$ 19,540	$ 6,070	$ 41,215	$ 30,933	$ 10,282

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 because it excludes expenses that are not directly related to the marketing and sales activities being evaluated. Margin and volume information for the three months and six months ended June 30, 2006 and 2005 is presented below (in thousands, except per barrel and per gallon amounts):

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Percentage Increase (Decrease)	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005	Percentage Increase (Decrease)
Margins: (1)						
Crude oil marketing	$ 19,096	$ 9,056	111%	$ 31,882	$ 12,532	154%
Lubrication oil sales	2,044	1,675	22%	4,175	3,432	22%
Revenues: (1)						
Crude oil transportation	16,586	14,968	11%	32,354	29,121	11%
Crude oil terminaling	3,553	2,046	74%	5,831	4,469	30%
Total margins/revenues	$ 41,279	$ 27,745	49%	$ 74,242	$ 49,554	50%
Total barrels/gallons:						
Crude oil marketing (barrels)	56,257	48,864	15%	109,198	93,158	17%
Lubrication oil volume (gallons)	3,377	3,153	7%	7,232	7,325	(1)%
Crude oil transportation (barrels)	22,847	23,768	(4)%	45,175	47,522	(5)%
Crude oil terminaling (barrels)	38,305	21,287	80%	62,748	48,406	30%
Margin per barrel or gallon:						
Crude oil marketing (per barrel)	$ 0.339	$ 0.185	83%	$ 0.292	$ 0.135	116%
Lubrication oil margin (per gallon)	0.605	0.531	14%	0.577	0.469	23%
Average tariff per barrel:						
Crude oil transportation	$ 0.726	$ 0.630	15%	$ 0.716	$ 0.613	17%
Crude oil terminaling	0.093	0.096	(3)%	0.093	0.092	1%

(1) Amounts 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 operating income using the information presented in the consolidated statements of income and the statements of income in Note 12 in the Notes to the Consolidated Financial Statements (in thousands):

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Sales of petroleum products	$ 2,273,878	$ 1,961,302	$ 4,674,314	$ 3,346,369
Transportation – Crude oil	10,544	9,042	19,467	18,214
Less: Purchases of petroleum products	(2,243,143)	(1,942,599)	(4,619,539)	(3,315,029)
Total margins/revenues	41,279	27,745	74,242	49,554
Other operating revenues	2,590	2,656	4,813	5,197
Net operating revenues	43,869	30,401	79,055	54,751
Operating expense	14,837	11,693	27,981	23,001
Operating fuel and power	1,766	1,234	3,959	2,462
General and administrative expense	1,870	1,219	3,677	2,727

Depreciation and amortization	3,494	3,651	6,765	7,152
Taxes – other than income taxes	1,557	1,068	3,022	2,469
Gains on sales of assets	—	(53)	—	(52)
Operating income	$ 20,345	$ 11,589	$ 33,651	$ 16,992

On April 1, 2006, we adopted Emerging Issues Task Force ("EITF") 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (see Note 1 in the Notes to the Consolidated Financial Statements), which resulted in crude oil inventory purchases and sales under buy/sell transactions, which were previously recorded as gross purchases and sales, to be treated as inventory exchanges in our consolidated statements of income. Implementation of EITF 04-13 as of April 1, 2006, reduced gross revenues and purchases for the three months ended June 30, 2006, but did not have a material effect on our financial position, results of operations or cash flows. Under the consensus reached in EITF 04-13, buy/sell transactions are reported as non-monetary exchanges and consequently not presented on a gross basis in our statements of income. Implementation of EITF 04-13 reduced revenues and purchases of petroleum products on our consolidated statements of income by approximately $313.7 million for the periods ended June 30, 2006. Under the provisions of the consensus, retroactive restatement of buy/sell transactions reported in prior periods was not permitted.

Three Months Ended June 30, 2006 Compared with Three Months Ended June 30, 2005

Sales of petroleum products increased $312.6 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005. Purchases of petroleum products increased $300.5 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005. Operating income increased $8.8 million for the three months ended June 30, 2006, compared with the three months ended June 20, 3005. The increases in sales and purchases were primarily as a result of an increase in the price of crude oil and increased volumes marketed. The average NYMEX price of crude oil was $70.40 per barrel for the three months ended June 30, 2006, compared with $53.03 per barrel for the three months ended June 30, 2005. The increase in the average price of crude oil, partially offset by increased purchases and costs and expenses discussed below, resulted in an increase in operating income. Crude oil marketing margin increased $10.0 million primarily due to favorable market conditions and increased volumes marketed, partially offset by increased transportation costs and unrealized gains in the 2005 period of $1.8 million relating to marking crude oil grade and location swap contracts to current market value. Crude oil transportation revenues increased $1.6 million primarily due to increased transportation revenues on the Red River system, the South Texas system and the West Texas system primarily related to movements on higher tariff segments, increased tariffs and revenues from systems acquired during 2005 and increases due to organic growth projects, partially offset by lower transportation volumes. Crude oil terminaling revenues increased

$1.5 million as a result of increased pumpover volumes at Midland, Texas and Cushing, Oklahoma. Lubrication oil sales margin increased $0.4 million due to increased sales of chemical volumes.

Costs and expenses, excluding expenses associated with purchases of crude oil and lubrication oil, increased $4.7 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005. Operating expenses increased $3.1 million from the prior year period primarily due to a $1.6 million increase in product measurement losses, a $0.7 million increase in pipeline operating and maintenance expense as a result of acquisitions and the continued integration of Genesis assets into our system, $0.4 million in severance expense as a result of the migration to a shared services environment with EPCO, higher insurance premiums and expenses relating to the proposed reduction in the General Partner's maximum percentage interest in our distributions (see Note 9 in the Notes to the Consolidated Financial Statements). General and administrative expenses increased $0.7 million from the prior year period primarily due to $0.4 million in severance expense as a result of the migration to a shared services environment with EPCO and higher other executive compensation expense. Operating fuel and power increased $0.5 million primarily as a result of higher power rates in the 2006 period. Taxes – other than income taxes increased $0.5 million from the prior year period primarily due to a higher property asset base in 2006 and an increase in payroll tax expense. Depreciation and amortization expense decreased $0.2 million as a result of asset retirements during the prior year period.

Equity earnings from our investment in Seaway decreased $3.0 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005. Our equity earnings in Seaway were reduced by a decrease in our participation ratio in the revenue and expense of Seaway. Our sharing ratio for 2005 was 60%, while for the full year of 2006, it is 47% of the revenue and expense of Seaway (see Note 7 in the Notes to the Consolidated Financial Statements). Equity earnings from our investment in Seaway also decreased due to higher operating, general and administrative expenses related to pipeline integrity costs for the corrective measures taken for the pipeline release in May 2005, increased environmental remediation and assessment costs and higher operating fuel and power costs relating to the use of a drag reducing agent and higher power rates, partially offset by increased 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 was determined. Corrective measures were implemented upon the release in 2005 and have been completed. Seaway operated at reduced maximum pressure through May 2006. On June 1, 2006, Seaway's operating pressure was increased to 100%. As a result of operating at reduced maximum pressure, 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. The reduced pressure did not have a material adverse effect on our financial position, results of operations or cash flows (see Note 13 in the Notes to the Consolidated Financial Statements).

Six Months Ended June 30, 2006 Compared with Six Months Ended June 30, 2005

Sales of petroleum products increased $1,327.9 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005. Purchases of petroleum products increased $1,304.5 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005. Operating income increased $16.7 million for the three months ended June 30, 2006, compared with the three months ended June 30, 3005. The increases in sales and purchases were primarily as a result of an increase in the price of crude oil and increased volumes marketed. The average NYMEX price of crude oil was $66.84 per barrel for the six months ended June 30, 2006, compared with $51.37 per barrel for the six months ended June 30, 2005. The increase in the average price of crude oil, partially offset by increased purchases and costs and expenses discussed below, resulted in an increase in operating income. Crude oil marketing margin increased $19.4 million, primarily due to favorable market conditions and increased volumes marketed, partially offset by increased transportation costs and unrealized gains in the 2005 period of $0.8 million relating to marking crude oil grade and location swap contracts to current market value. Crude oil transportation revenues increased $3.2 million primarily due to increased transportation volumes and revenues on our South Texas system and West Texas systems, higher revenues on our Red River system related to movements on higher tariff segments and revenues from acquisitions in 2005, partially offset by decreases in transportation volumes on lower tariff segments of our Basin and Red River systems. Crude oil terminaling revenues increased $1.4 million as a result of an increase in pumpover volumes at Midland, Texas and Cushing, Oklahoma. Lubrication oil sales margin increased $0.7 million due to increased sales of chemical volumes.

Other operating revenues decreased $0.4 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, primarily due to a $1.4 million favorable settlement of inventory imbalances in the first quarter of 2005 and lower revenues from documentation and other services to support customers' trading activity at Midland and Cushing in the first six months of 2006.

Costs and expenses, excluding expenses associated with purchases of crude oil and lubrication oil, increased $7.7 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005. Operating expenses increased $5.0 million from the prior year period, primarily due to a $3.1 million increase in supplies and pipeline operating and maintenance expense, a $1.0 million increase as a result of product measurement losses and higher crude oil prices, $0.8 million of higher insurance premiums, a $0.5 million increase in environmental assessment and remediation costs and $0.4 million in severance expense as a result of the migration to a shared services environment with EPCO, partially offset by a $0.6 million decrease in labor and benefits expense related to vesting provisions in certain of our compensation plans as a result of changes in ownership of our General Partner in the prior year period. Operating fuel and power increased $1.5 million primarily as a result of increased power rates in the 2006 period, partially offset by lower transportation volumes. General and administrative expenses increased $1.0 million from the prior year period primarily due to $0.4 million in severance expense, an increase in other executive compensation expense and an increase in consulting and contract services. Taxes – other than income taxes increased $0.5 million due to increases in property tax accruals and a higher property asset base in 2006. Depreciation and amortization expense decreased $0.4 million as a result of asset retirements during the prior year period.

Equity earnings from our investment in Seaway decreased $6.6 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005. Our sharing ratio for 2005 was 60%, while for the full year of 2006, it is 47% of the revenue and expense of Seaway (see Note 7 in the Notes to the Consolidated Financial Statements). Equity earnings from our investment in Seaway also decreased due to higher operating, general and administrative expenses related to pipeline integrity costs for the corrective measures taken for the pipeline release in May 2005, increased environmental remediation and assessment costs, higher operating fuel and power costs relating to the use of a drag reducing agent and higher power rates and a favorable settlement in the first quarter of 2005 with a former owner of Seaway's crude oil assets regarding inventory imbalances that were not acquired by us, partially offset by increased transportation volumes.

Midstream Segment

The following table provides financial information for the Midstream Segment for the three months and six months ended June 30, 2006 and 2005 (in thousands):

	Three Months Ended June 30,		Increase	Six Months Ended June 30,		Increase
	2006	2005	(Decrease)	2006	2005	(Decrease)
Revenues:						
Sales of petroleum products	$ 13,776	$ —	$ 13,776	$ 13,776	$ —	$ 13,776
Gathering – Natural Gas	41,459	36,956	4,503	82,834	73,516	9,318
Transportation – NGLs	10,738	11,387	(649)	21,391	21,606	(215)
Other	4,372	3,313	1,059	8,721	6,718	2,003
Total operating revenues	70,345	51,656	18,689	126,722	101,840	24,882
Costs and expenses:						
Purchases of petroleum products	12,949	—	12,949	12,949	—	12,949
Operating expense	14,435	7,256	7,179	24,593	16,210	8,383
Operating fuel and power	2,903	2,355	548	5,702	4,537	1,165
General and administrative expense	2,587	1,372	1,215	4,887	2,867	2,020
Depreciation and amortization	15,049	12,686	2,363	30,238	25,235	5,003
Taxes – other than income taxes	1,371	731	640	2,622	1,825	797
Gains on sales of assets	—	—	—	(1,371)	(407)	(964)
Total costs and expenses	49,294	24,400	24,894	79,620	50,267	29,353
Operating income	21,051	27,256	(6,205)	47,102	51,573	(4,471)
Other income – net	44	60	(16)	120	102	18
Earnings before interest	$ 21,095	$ 27,316	$ (6,221)	$ 47,222	$ 51,675	$ (4,453)

The following table presents volume and average rate information for the Midstream Segment for the three months and six months ended June 30, 2006 and 2005:

	Three Months Ended June 30,		Percentage Increase	Six Months Ended June 30,		Percentage Increase
	2006	2005	(Decrease)	2006	2005	(Decrease)
Gathering – Natural Gas – Jonah:						
Million cubic feet ("MMcf")	111,346	99,045	12%	220,016	196,395	12%
Billion British thermal units ("BBtu")	122,969	109,516	12%	242,976	216,817	12%
Average fee per Million British thermal unit ("MMBtu")	$ 0.210	$ 0.189	11%	$ 0.208	$ 0.189	10%
Gathering – Natural Gas – Val Verde:						

MMcf	46,938	44,560	5%	92,288	87,885	5%
BBtu	41,675	39,451	6%	81,606	77,540	5%
Average fee per MMBtu	$ 0.389	$ 0.411	(5)%	$ 0.404	$ 0.420	(4)%
Transportation – NGLs:						
Thousand barrels	17,652	15,540	14%	33,518	29,376	14%
Average rate per barrel	$ 0.608	$ 0.733	(17)%	$ 0.638	$ 0.735	(13)%
Natural Gas Sales:						
BBtu	2,627	—	—	2,627	—	—
Average fee per MMBtu	$ 5.242	$ —	—	$ 5.242	$ —	—
Fractionation – NGLs:						
Thousand barrels	1,125	1,087	3%	2,277	2,226	2%
Average rate per barrel	$ 1.850	$ 1.820	2%	$ 1.666	$ 1.732	(4)%
Sales – Condensate:						
Thousand barrels	18.3	13.3	38%	43.0	41.2	4%
Average rate per barrel	$ 68.20	$ 53.24	28%	$ 65.52	$ 49.77	32%

Three Months Ended June 30, 2006 Compared with Three Months Ended June 30, 2005

Revenues from the gathering of natural gas increased $4.5 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005. Natural gas gathering revenues from the Jonah system increased $4.5 million and volumes gathered increased 12.3 billion cubic feet (“Bcf”) for the three months ended June 30, 2006, primarily due to the expansion of the Jonah system in 2005. The Phase IV expansion project on Jonah was completed in February 2006. The expansion increased the system capacity of Jonah to 1.5 Bcf per day with the addition of 33,000 horsepower of compression and approximately 50 miles of pipeline. Jonah’s average natural gas gathering rate per MMcf increased due to lower system wellhead pressures. Natural gas gathering revenues from the Val Verde system remained constant and volumes gathered increased 2.4 Bcf for the three months ended June 30, 2006, primarily due to increased volumes from a natural gas connection on the Val Verde system and increased volumes from temporary interconnects with third party gatherers, partially offset by a decrease in the average natural gas gathering rate. 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.

In late 2005, we began to aggregate purchases of wellhead gas on Jonah and re-sell the aggregated quantities at key Jonah delivery points in order to facilitate throughput on Jonah. The purchases and sales are generally contracted to occur in the same month to minimize price risk. During the second quarter of 2006, gas purchase and sales contracts were finalized and executed and the marketing of gas on the Jonah system began. Sales from petroleum products relating to the natural gas marketing activities were $13.8 million for the three months ended June 30, 2006, and purchases of petroleum products were $13.0 million.

Revenues from the transportation of NGLs decreased $0.7 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005, primarily due to a decrease in the average NGL transportation rate per barrel due to increased short-haul movements on the Chaparral Pipeline and a lower average rate per barrel on the Panola Pipeline. During the 2006 period, volumes of NGLs transported increased due to increases on the Chaparral, Panola and Dean Pipelines, partially offset by decreased volumes transported on the Wilcox Pipeline.

Other operating revenues increased $1.1 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005, primarily due to new pipeline capacity leases on the Chaparral and Panola Pipelines and higher condensate sales on Jonah.

Costs and expenses (excluding purchases of petroleum products) increased $11.9 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005. Operating expense increased $7.2 million primarily due to $2.3 million of expenses relating to the formation of a joint venture for the expansion of the Jonah system and to the proposed reduction in the General Partner’s maximum percentage interest in our distributions (see Note 9 in the Notes to the Consolidated Financial Statements), a $1.7 million increase related to imbalance valuations, $0.8 million in severance expense as a result of the migration to a shared services environment with EPCO and an increase in other pipeline operating and maintenance expense. Depreciation expense increased $1.3 million primarily due to an increase on Jonah as a result of assets placed into service from the Phase IV expansion. Amortization expense increased $1.1 million primarily due to an increase of $0.9 million on Val Verde due to higher volumes on contracts included in the intangible assets in the 2006 period. General and administrative expense increased $1.2 million primarily due to $0.6 million in severance expense as a result of the migration to a shared services environment with EPCO and an increase in consulting and contract services. Taxes – other than income taxes increased $0.6 million due to actual property taxes being higher than previously estimated and a higher property asset base in the 2006 period. Operating fuel and power increased $0.5 million primarily due to higher transportation volumes and power rates.

Six Months Ended June 30, 2006 Compared with Six Months Ended June 30, 2005

Revenues from the gathering of natural gas increased $9.3 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005. Natural gas gathering revenues from the Jonah system increased $8.9 million and volumes gathered increased 23.6 Bcf for the six months ended June 30, 2006, primarily due to the expansion of the Jonah system in 2005. Jonah’s average natural gas gathering rate per MMcf increased due to lower system wellhead pressures. Natural gas gathering revenues from the Val Verde system increased $0.4 million and volumes gathered increased 4.4 Bcf for the six months ended June 30, 2006, primarily due to increased volumes from a natural gas connection on the Val Verde system, better performance from coal seam infill wells and increased volumes from temporary interconnects with third party gatherers. 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.

Sales from petroleum products relating to natural gas marketing activities were $13.8 million for the six months ended June 30, 2006, and purchases of petroleum products were $13.0 million.

Revenues from the transportation of NGLs decreased $0.2 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, due to a decrease in the average NGL transportation rate per barrel primarily due to an increase in short-haul movements on the Chaparral Pipeline and a lower average rate per barrel on the Panola Pipeline. During the 2006 period, volumes of NGLs transported increased due to increases on the Chaparral, Panola and Dean Pipelines, partially offset by decreased volumes transported on the Wilcox Pipeline.

Other operating revenues increased $2.0 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005. Other operating revenues increased $1.4 million as a result of new pipeline capacity leases on the Chaparral Pipeline and the Panola Pipeline and $0.7 million on Jonah primarily due to higher condensate sales.

Costs and expenses (excluding purchases of petroleum products) increased $16.4 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005. Operating expense increased $8.4 million primarily due to $2.3 million of expenses relating to the formation of a joint venture for the expansion of the Jonah system and to the proposed reduction in the General Partner's maximum percentage interest in our distributions (see Note 9 in the Notes to the Consolidated Financial Statements), a $2.3 million increase related to imbalance valuations, $0.8 million in severance expense as a result of the migration to a shared services environment with EPCO and an increase in other pipeline operating and maintenance expense. Depreciation expense increased $2.8 million primarily due to an increase on Jonah as a result of assets placed into service from the Phase IV expansion. Amortization expense increased $2.2 million primarily due to an increase of $2.0 million on Val Verde due to higher volumes on contracts included in the intangible assets in the 2006 period. General and administrative expense increased $2.0 million primarily due to $0.6 million in severance expense as a result of the migration to a shared services environment with EPCO and an increase in consulting and contract services and supplies expense. Operating fuel and power increased $1.2 million primarily due to higher transportation volumes and power rates. Taxes – other than income taxes increased $0.8 million due to actual property taxes being higher than previously estimated and a higher property asset base in the 2006 period. During the six months ended June 30, 2006 and 2005, gains of $1.0 million and $0.4 million, respectively, were recognized on the sales of various equipment at Val Verde.

Discontinued Operations

On March 31, 2006, we sold our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise for $38.0 million in cash. The Pioneer plant was not an integral part of our Midstream Segment operations, and natural gas processing is not a core business. We have no continuing involvement in the operations or results of this plant. This transaction was reviewed and approved by the Audit and Conflicts Committee of the board of directors of our General Partner and a fairness opinion was rendered by an independent third-party. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of the Pioneer plant at March 31, 2006, prior to the sale, was $19.7 million. Costs associated with the completion of the transaction were approximately $0.4 million.

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the three months and six months ended June 30, 2006 and 2005, are presented below (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Sales of petroleum products	$ 18	$ 2,315	$ 3,828	$ 4,457
Other	11	680	932	1,352
Total operating revenues	29	2,995	4,760	5,809
Purchases of petroleum products	139	1,806	3,000	3,176
Operating expenses	—	158	182	296
Depreciation and amortization	—	154	51	306
Taxes – other than income taxes	—	31	30	61
Total costs and expenses	139	2,149	3,263	3,839
Income (loss) from discontinued operations	$ (110)	$ 846	$ 1,497	$ 1,970

Sales of petroleum products less purchases of petroleum products resulting from the processing activities at the Jonah Pioneer plant decreased $0.5 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, primarily due to the sale of the Pioneer plant on March 31, 2006, partially offset by increased NGL prices. The Pioneer gas processing plant was completed during the first quarter of 2004, as a part of Jonah's Phase III expansion to increase the processing capacity in southwestern Wyoming. Pioneer's processing agreements allowed the producers to elect annually whether to be charged under a fee-based arrangement or a fee

plus keep-whole arrangement. Under the fee-based election, Jonah received a fee for its processing services. Under the fee plus keep-whole election, Jonah received a lower fee for its processing services, retained and sold the NGLs extracted during the process and delivered to producers the residue gas equivalent in energy to the natural gas received from the producers. Jonah sold the NGLs it retained and purchased gas to replace the equivalent energy removed in the liquids. For the 2005 and 2006 periods, the producers elected the fee plus keep-whole arrangement.

Interest Expense and Capitalized Interest

Three Months Ended June 30, 2006 Compared with Three Months Ended June 30, 2005

Interest expense decreased $0.4 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005, primarily due to reductions in interest expense of $2.5 million during 2006 related to interest rate swaps and $2.0 million of increased interest expense in the 2005 period related to the termination of a treasury lock (see Note 3 in the Notes to the Consolidated Financial Statements), partially offset by higher outstanding borrowings and higher short term floating interest rates on our revolving credit facility.

Capitalized interest increased $2.0 million for the three months ended June 30, 2006, compared with the three months ended June 30, 2005, due to higher construction work-in-progress balances in 2006 as compared to the 2005 period.

Six Months Ended June 30, 2006 Compared with Six Months Ended June 30, 2005

Interest expense increased $3.6 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, primarily due to higher outstanding borrowings and higher short term floating interest rates on our revolving credit facility, partially offset by reductions in interest expense of

$2.5 million during 2006 related to our interest rate swaps and $2.0 million of increased interest expense in the 2005 period related to the termination of a treasury lock (see Note 3 in the Notes to the Consolidated Financial Statements).

Capitalized interest increased $4.2 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, due to higher construction work-in-progress balances in 2006 as compared to the 2005 period.

Deferred Income Tax Expense — Texas Margin Tax

In May 2006, the State of Texas enacted a new business tax (the "Texas Margin Tax") that replaces its existing franchise tax. In general, legal entities that do business in Texas are subject to the new margin tax. Limited partnerships, limited liability companies, corporations, limited liability partnerships and joint ventures are examples of the types of entities that are subject to the Texas Margin Tax. As a result of this change in tax law, our tax status in the state of Texas changed from nontaxable to taxable. The Texas Margin Tax is considered an income tax for purposes of adjustments to deferred tax liability, as the tax is determined by applying a tax rate to a base that considers both revenues and expenses. Our deferred income tax expense for state taxes relates only to Texas Margin Tax obligations. The Texas Margin Tax becomes effective for franchise tax reports due on or after January 1, 2008. The Texas Margin Tax due in 2008 will be based on revenues earned during the 2007 fiscal year.

The Texas Margin Tax is assessed at 1% of Texas-sourced taxable margin measured by the ratio of gross receipts from business done in Texas to gross receipts from business done everywhere. The taxable margin is computed as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation. The deferred tax liability shown on our consolidated balance sheet reflects the net tax effect of temporary differences related to items such as property, plant and equipment; therefore, the deferred tax liability is classified as noncurrent. The Texas Margin Tax is calculated, paid and filed at an affiliated unitary group level. Generally, an affiliated group is made up of one or more entities in which a controlling interest of at least 80% is owned by a common owner or owners. Generally, a business is unitary if it is characterized by a sharing or exchange

of value between members of the group, and a synergy and mutual benefit all of the members of the group achieved by working together.

Since the Texas Margin Tax is determined by applying a tax rate to a base that considers both revenues and expenses, it has characteristics of an income tax. Accordingly, we determined the Texas Margin Tax should be accounted for as an income tax in accordance with the provisions of SFAS No. 109, *Accounting for Income Taxes*. The base used to compute the Texas Margin Tax affects book-tax differences. All effects of a tax law change are accounted for in the period of the law's enactment. A change in tax status that results from a change in tax law is recognized on the enactment date and the effect of recognizing a deferred tax liability or asset is included in income from continuing operations. Therefore, we have calculated and recorded an estimated deferred tax liability of approximately $0.5 million using the enacted tax rate expected to apply to taxable income in the periods in which the deferred tax liability is expected to be realized or settled.

The constitutionality of the Texas Margin Tax is being questioned. The Texas Comptroller has requested a formal opinion from the Texas Attorney General on whether the Texas Margin Tax is an impermissible income tax that violates the Texas constitution. The Texas constitution requires voter approval of any tax imposed on the net income of natural persons, including a person's share of partnership unincorporated association income; such approval was not obtained for the Texas Margin Tax. The Comptroller has requested that the Attorney General determine whether the direct imposition of the Texas Margin Tax on parterships without voter approval violates this constitutional requirement. The Attorney General's decision is not expected until late 2006 or early 2007. If the Texas Margin Tax is ultimately challenged in court, the legislation enacting the Texas Margin Tax gives the Texas Supreme Court jurisdiction over the constitutional challenge and allows the Court to grant injunctive or declaratory relief. The Court would have 120 days from the date the challenge is filed to make a ruling.

Financial Condition and Liquidity

Cash generated from operations, credit facilities and debt and equity offerings are our primary sources of liquidity. At June 30, 2006, and December 31, 2005, we had working capital deficits of $7.2 million and $38.1 million, respectively. At June 30, 2006, we had approximately $240.8 million in available borrowing capacity under our revolving credit facility to cover any working capital needs. Cash flows for the six months ended June 30, 2006 and 2005 were as follows (in millions):

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Cash provided by (used in):		
Operating activities	$ 143.1	$ 30.0
Investing activities	(48.3)	(131.4)
Financing activities	(94.7)	86.5

Operating Activities

Net cash from operating activities for the six months ended June 30, 2006 and 2005, was comprised of the following (in millions):

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Net income	$ 104.3	$ 88.4

Income from discontinued operations	(19.4)	(2.0)
Deferred income tax expense	0.5	—
Depreciation and amortization	57.4	51.7
Earnings in equity investments	(3.7)	(11.9)
Distributions from equity investments	16.3	19.0
Gains on sales of assets	(1.4)	(0.6)
Non-cash portion of interest expense	0.8	0.8
Cash used in working capital and other	(13.2)	(117.7)
Net cash provided by continuing operating activities	141.6	27.7
Cash flows from discontinued operations	1.5	2.3
Net cash from operating activities	$ 143.1	$ 30.0

Net cash provided by operating activities increased $113.1 million for the six months ended June 30, 2006, compared with the six months ended June 30, 2005, primarily due to a decrease of $67.6 million in crude oil inventory (as discussed below) and due to the timing of cash disbursements and cash receipts for other working capital components, partially offset by a decrease of $2.7 million in distributions received from our equity investments in Seaway and MB Storage. For a discussion of changes in earnings before interest, depreciation and amortization expense, equity earnings and consolidated interest expense – net, see Results of Operations for the Downstream Segment, Upstream Segment and Midstream Segment in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

During the second quarter 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 was stored in our facilities. These purchases of crude oil had a negative impact on cash from operating activities (as discussed above) until the crude oil was delivered and payment was received from customers.

Net cash from operating activities for the six months ended June 30, 2006 and 2005, included interest payments, net of amounts capitalized, of $42.1 million and $41.1 million, respectively. Excluding the effects of hedging activities and interest capitalized during the year ended December 31, 2006, we expect interest payments on our fixed rate Senior Notes to be approximately $78.0 million. We expect to pay our interest payments with cash flows from operating activities.

Investing Activities

Cash flows used in investing activities totaled $48.3 million for the six months ended June 30, 2006, and were comprised of $82.5 million of capital expenditures, $2.5 million of cash contributions for TE Products' ownership interest in Centennial for operating needs, $1.7 million of cash contributions for TE Products' ownership interest in MB Storage for capital expenditures and $1.4 million of cash paid for linefill on assets owned, partially offset by $39.8 million in net cash proceeds from asset sales in our Midstream Segment, of which $38.0 million related to cash proceeds received from the sale of the Pioneer plant on March 31, 2006. Cash flows used in investing activities totaled $131.4 million for the six months ended June 30, 2005, and were comprised of $82.9 million of capital expenditures, $42.5 million for the acquisition of crude oil assets, $5.4 million of cash paid for linefill on

assets owned and $1.1 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 asset sales in our Upstream and Downstream Segments.

Financing Activities

Cash flows used in financing activities totaled $94.7 million for the six months ended June 30, 2006, and were comprised of $133.8 million of distributions paid to unitholders, partially offset by $39.1 million in borrowings, net of repayments, on our revolving credit facility. Cash flows provided by financing activities totaled $86.5 million for the six months ended June 30, 2005, and were comprised of $278.8 million from the issuance of 7.0 million Units in May and June 2005, partially offset by $117.3 million of distributions paid to unitholders and $75.0 million in repayments, net of borrowings, on our revolving credit facility.

We paid cash distributions of $133.8 million ($1.350 per Unit) and $117.3 million ($1.325 per Unit) during each of the six months ended June 30, 2006 and 2005, respectively. Additionally, we declared a cash distribution of $0.675 per Unit for the quarter ended June 30, 2006. We will pay the distribution of $72.4 million on August 7, 2006, to unitholders of record on July 31, 2006.

In July 2006, we issued and sold in an underwritten public offering 5.0 million Units at a price to the public of $35.50 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $170.4 million. On July 12, 2006, 750,000 additional Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering. Proceeds from the over-allotment sale, net of underwriting discount, totaled $25.6 million. The net proceeds from the offering and the over-allotment were used to reduce indebtedness under our Revolving Credit Facility.

Other Considerations

Universal Shelf

We have filed with the Securities and Exchange Commission 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. Taking into account our May 2005 and July 2006 equity offerings, in which we issued $290.8 million and $204.1 million of equity securities, respectively, we had $1.5 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 $700.0 million ("Revolving Credit Facility"), which may be increased up to a maximum of $850.0 million upon our request, subject to lender approval and the satisfaction of certain other conditions. The Revolving Credit Facility expires on December 13, 2010. Interest is payable at an applicable margin above either the lender's base rate or LIBOR. At June 30, 2006, $445.0 million was outstanding under the facility, and we had $240.8 million of available borrowing capacity, which includes $14.2 million of outstanding letters of credit. Financial covenants in the Revolving Credit Facility require that we maintain a ratio of Consolidated Funded Debt to Pro Forma EBITDA (as defined and calculated in the facility) of less than 4.75 to 1.00 (subject to adjustment for specified acquisitions) and a ratio of EBITDA to Interest Expense (as defined and calculated in the facility) of at least 3.00 to 1.00, in each case with respect to specified twelve month periods. Other restrictive covenants in the credit agreement limit our ability to, among other things, incur additional indebtedness, make distributions in excess of Available Cash, incur liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets. At June 30, 2006, we were in compliance with the covenants of the Revolving Credit Facility. In July 2006, we used the net proceeds of $195.5 million from the July 2006 equity offering to reduce outstanding borrowings under the Revolving Credit Facility.

On July 31, 2006, we executed a third amendment ("Third Amendment") to our Revolving Credit Facility which extends the maturity date of amounts borrowed under the Revolving Credit Facility from December 2010 to December 2011. The Third Amendment also releases Jonah as a guarantor of the Revolving Credit Facility. The Third Amendment restricts the amount of outstanding debt of the Jonah joint venture to debt owing to the owners of its partnership interests and other debt in the principal aggregate amount of $50.0 million. In addition, the Third Amendment allows for swing line loans up to $25.0 million (within the $700.0 million total borrowing limit) and modifies our financial covenants to, among other things, allow us to include in the calculation of our Consolidated EBITDA (as defined in the Revolving Credit Facility, as amended) pro forma adjustments for material projects.

Effective July 31, 2006, Jonah Gas Gathering Company was also released from its guarantee to Wachovia Bank pursuant to the provisions of Section 14.04 dated as of February 20, 2002, of the Indenture between us, as issuer, TE Products, TCTM, TEPPCO Midstream and Jonah Gas Gathering Company, each as subsidiary guarantors and Wachovia Bank, as trustee.

Future Capital Needs and Commitments

We estimate that capital expenditures, excluding acquisitions, for 2006 will be approximately $271.1 million (including $6.0 million of capitalized interest). We expect to spend approximately $195.0 million for revenue generating projects. Capital spending on revenue generating projects and facility improvements will include approximately $85.4 million for the expansion of our Downstream Segment facilities. We expect to spend $45.5 million to expand our Upstream Segment pipelines and facilities in West Texas and Oklahoma and approximately $64.1 million to expand our Midstream Segment assets, with further expansions on our Jonah system. We expect to spend approximately $39.9 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 $30.2 million to improve operational efficiencies and reduce costs among all of our business segments. During 2006, TE Products may be required to contribute additional cash to Centennial to cover capital expenditures, acquisitions or other operating needs and to MB Storage to cover significant capital expenditures or additional acquisitions. We continually review and evaluate potential capital improvements and expansions that would be complementary to our present business operations. These expenditures can vary greatly depending on the magnitude of our transactions. We may finance capital expenditures through internally generated funds, debt or the issuance of additional equity.

Additionally, during the remainder of 2006, we expect to contribute approximately $119.0 million to our Jonah joint venture for the construction of the Phase V expansion. In August 2006, we entered into an amended and restated general partnership agreement forming a joint venture to expand our Jonah system with an affiliate of Enterprise. For additional information, see "-Overview of Business" above.

Liquidity Outlook

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

Off-Balance Sheet Arrangements

We do not rely on off-balance sheet borrowings to fund our acquisitions. We have no material off-balance sheet commitments for indebtedness other than the limited guaranty of Centennial debt, the limited guarantee of

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Centennial catastrophic events as discussed below and an outstanding letter of credit. In addition, we have entered into various leases covering assets utilized in several areas of our operations.

Centennial entered into credit facilities totaling $150.0 million, and as of June 30, 2006, $150.0 million was outstanding under those credit facilities, of which $140.0 million expires in 2024, and $10.0 million expires in April 2007. 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 these credit facilities. The guarantees arose in order for Centennial to obtain adequate financing, and the proceeds of the credit facilities were used to fund construction and conversion costs of its pipeline system. Prior to the expiration of the long-term credit facility, 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 June 30, 2006.

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 $4.5 million obligation, which represents the present value of the estimated amount that we would have to pay under the guarantee. If a catastrophic event were to occur and we were required to contribute cash to Centennial, contributions exceeding our deductible might be covered by our insurance.

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

Contractual Obligations

The following table summarizes our debt repayment obligations and material contractual commitments as of June 30, 2006 (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	$ 445.0	$ —	$ —	$ 445.0	$ —
6.45% Senior Notes due 2008 (1) (2)	180.0	—	180.0	—	—
7.625% Senior Notes due 2012 (2)	500.0	—	—	—	500.0
6.125% Senior Notes due 2013 (2)	200.0	—	—	—	200.0
7.51% Senior Notes due 2028 (1) (2)	210.0	—	—	—	210.0
Interest payments (3)	799.6	103.5	195.5	169.9	330.7
Debt and interest subtotal	2,334.6	103.5	375.5	614.9	1,240.7
Operating leases (4)	75.3	18.4	24.4	13.6	18.9
Capital expenditure obligations (5)	1.0	1.0	—	—	—
Standby letter of credit (6)	14.2	14.2	—	—	—
Other liabilities and deferred credits (7)	14.6	—	13.5	0.3	0.8
Total	$ 2,439.7	$ 137.1	$ 413.4	$ 628.8	$ 1,260.4

(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 June 30, 2006, the 7.51% Senior Notes include an adjustment to decrease the fair value of the debt by $11.3 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 June 30, 2006, the 7.625% Senior Notes include a deferred gain, net of amortization, from previous interest rate swap terminations of $30.2 million. At June 30, 2006, our 6.45% Senior Notes, our 7.625% Senior Notes and our 6.125% Senior Notes include $2.2 million of unamortized debt discounts. The fair value adjustments, the deferred gain adjustment and the unamortized debt discounts are excluded from this table.

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

(4) Includes a pipeline capacity lease with Centennial. In January 2003, TE Products entered into a pipeline capacity lease agreement with Centennial for a period of five years that contains a minimum throughput requirement. For the six months ended June 30, 2006, TE Products exceeded the minimum throughput requirements on the lease agreement.

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

(6) At June 30, 2006, we had outstanding a $14.2 million standby letter of credit in connection with crude oil purchased in the first quarter of 2006. The payable related to these purchases of crude oil is expected to be paid during the third quarter of 2006.

(7) Excludes approximately $8.4 million of long-term deferred revenue payments, which are being transferred to income over the term of the respective revenue contracts and $4.2 million related to our estimated long-term portion of our obligation under a catastrophic event guarantee for Centennial. The amount of commitment by year is our best estimate of projected payments of these long-term liabilities.

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

In addition to the items in the table above, we have entered into various operational commitments and agreements related to pipeline operations and to the marketing, transportation, terminaling and storage of crude oil. The majority of contractual commitments we make for the purchase of crude oil range in term from a thirty-day evergreen to one year. A substantial portion of the contracts for the purchase of crude oil that extend beyond thirty days include cancellation provisions that allow us to cancel the contract with thirty days written notice. During the six months ended June 30, 2006, crude oil purchases averaged approximately $769.9 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 and should be evaluated independently of any other rating. 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 and were reaffirmed during the first quarter of 2006.

Recent Accounting Pronouncements

See discussion of new accounting pronouncements in Note 1 in the Notes to the Consolidated Financial Statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For additional discussion of our exposure to market risks, please refer to "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" in our Annual Report on Form 10-K for the year ended December 31, 2005.

Commodity 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 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*.

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. Generally, hedge accounting is elected. The terms of these contracts are typically one year or less. The purpose is to balance our position or lock in a margin and, as such, the derivative contracts do not expose us to additional significant market risk. For derivatives where hedge accounting is elected, the effective portion of changes in fair value are recorded in other comprehensive income and reclassified into earnings as such transactions are settled. For derivatives where hedge accounting is not elected, 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 June 30, 2006, we had a limited number of commodity derivatives that were accounted for as cash flow hedges. Gains and losses on these derivatives are offset against corresponding gains or losses of the hedged item and are deferred through other comprehensive income, thus minimizing exposure to cash flow risk. The fair value of the open positions at June 30, 2006, was a loss of $0.2 million. Assuming a hypothetical across-the-board 10% price decrease in the applicable forward curve, the change in fair value of the hedging instrument would have been $0.2 million. The fair value of the open positions was based upon both quoted market prices obtained from NYMEX and were estimated based on quoted prices from various sources such as independent reporting services, industry publications, brokers and marketers. The fair values were determined based upon the differences by month between the fixed contract price and the relevant forward price curve, the volumes for the applicable month and a discount rate of 6%.

Interest Rate Risk

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

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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.

At June 30, 2006, we had $445.0 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. On January 20, 2006, we entered into interest rate swap agreements with a total notional amount of $200.0 million to hedge our exposure to increases in the benchmark interest rate underlying our variable rate revolving credit facility. These interest rate swaps mature in January 2008. For the period from January 20, 2006 through June 30, 2006, changes in the fair value of the swaps were recognized in earnings, which for the six months ended June 30, 2006, was a $2.5 million reduction to interest expense. Under the swap agreements, we pay a fixed rate of interest ranging from 4.67% to 4.695% and receive a floating rate based on a three-month U.S. Dollar LIBOR rate. Because these swaps will be designated as cash flow hedges effective in the third quarter of 2006, future changes in fair value, to the extent the swaps are effective, will be recognized in other comprehensive income until the hedged interest costs are recognized in earnings. Utilizing the balances of our variable interest rate debt outstanding at June 30, 2006, and including the effects of hedging activities, if market interest rates increased 100 basis points, the annual increase in interest expense related to our revolving credit facility would be $2.4 million.

The following table summarizes the estimated fair values of the Senior Notes as of June 30, 2006 and December 31, 2005 (in millions):

		Fair Value	
	Face Value	June 30, 2006	December 31, 2005
6.45% TE Products Senior Notes, due January 2008	$ 180.0	$ 181.0	$ 183.7
7.625% Senior Notes, due February 2012	500.0	526.9	552.0
6.125% Senior Notes, due February 2013	200.0	196.1	205.6
7.51% TE Products Senior Notes, due January 2028	210.0	221.1	224.1

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 of 147 basis points, and receives a fixed rate of interest of 7.51%. During the six months ended June 30, 2006, and 2005, we recognized reductions in interest expense of $1.2 million and $3.3 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. During the quarters ended June 30, 2006 and 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 loss of approximately $11.3 million and $0.9 million at June 30, 2006, and December 31, 2005, respectively. Utilizing the balance of the 7.51% TE Products Senior Notes outstanding at June 30, 2006, and including the effects of hedging activities, if market interest rates increased 100 basis points, the annual increase in interest expense would be $2.1 million.

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 June 30, 2006, 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

There has been no change in our internal control over financial reporting during the second quarter of 2006 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 13 in the Notes to the Consolidated Financial Statements, which is incorporated into this item by reference.

Item 1A. Risk Factors

Unitholders and potential investors in our Units should carefully consider the following risk factors in addition to other information in this Report, our Annual Report on Form 10-K for the year ended December 31, 2005 and our Current Report on Form 8-K filed on June 16, 2006. We are identifying these risk factors as important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by or on behalf of us. We are relying upon the safe-harbor for forward-looking statements, and any such statements made by or on behalf of us are qualified by reference to the following cautionary statements, as well as to those set forth elsewhere in this Report.

Risks Relating to Our Business

Potential future acquisitions and expansions may affect our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing our risks of being unable to effectively integrate these new operations.

As part of our business strategy, we evaluate and acquire assets and businesses and undertake expansions that we believe complement our existing assets and businesses. Acquisitions and expansions may require substantial capital or the incurrence of substantial indebtedness. Consummation of future acquisitions and expansions may significantly change our capitalization and results of operations. Our growth may be limited if acquisitions or expansions are not made on economically favorable terms.

Acquisitions and business expansions involve numerous risks, including difficulties in the assimilation of the assets and operations of the acquired businesses, inefficiencies and difficulties that arise because of unfamiliarity with new assets, personnel and the businesses associated with them and new geographic areas and the diversion of management's attention from other business concerns. Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Following an acquisition, we may discover previously unknown liabilities

associated with the acquired business for which we may have no recourse or limited recourse under applicable indemnification provisions.

Our future debt level may limit our future financial and operating flexibility.

As of June 30, 2006, we had approximately $1.5 billion of consolidated debt outstanding, consisting of $445.0 million of borrowings under our revolving credit facility and $1.1 billion principal amount of senior notes. In July 2006, we used the net proceeds of $195.5 million from the July 2006 equity offering to reduce outstanding borrowings under the Revolving Credit Facility. The amount of our future debt could have significant effects on our operations, including, among other things:

- a significant portion of our cash flow could be dedicated to the payment of principal and interest on our future debt and may not be available for other purposes, including the payment of distributions on our Units and capital expenditures;
- credit rating agencies may view our debt level negatively;
- covenants contained in our existing debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;
- our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;
- we may be at a competitive disadvantage relative to similar companies that have less debt; and
- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

Our revolving credit facility contains restrictive financial and other covenants that, among other things, limit our ability to incur additional indebtedness, make distributions in excess of Available Cash (see Note 9 in the Notes to the Consolidated Financial Statements for discussion of Available Cash), and complete mergers, acquisitions and sales of assets. The facility also prevents us from making a distribution if an event of default under the facility has occurred or would occur as a result of the distribution. Our breach of these restrictions or restrictions in the provisions of our other indebtedness could permit the holders of the indebtedness to declare all amounts outstanding thereunder to be immediately due and payable and, in the case of our revolving credit facility, to terminate all commitments to extend further credit. Although our revolving credit facility restricts our ability to incur additional debt above certain levels, any debt we may incur in compliance with these restrictions may still be substantial.

Our ability to access capital markets to raise capital on favorable terms will be affected by our debt level, the amount of our debt maturing in the next several years and current maturities, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, difficulty accessing capital markets or a reduction in the market price of our Units. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness. If we are unable to access the capital markets on favorable terms at the time a debt obligation becomes due in the future, we might be forced to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected rates.

Our cash distributions may vary based on our operating performance and level of cash reserves.

Distributions are dependent on the amount of cash we generate and may fluctuate based on our performance. We cannot guarantee that we will continue to pay distributions at the current level each quarter. The actual amount of cash that is available to be distributed each quarter will depend upon numerous factors, some of which are beyond our control and the control of our General Partner. These factors include but are not limited to the following:

- the volume of products that we handle and the prices we receive for our services;
- the level of our operating costs;
- the level of competition in our business segments;
- prevailing economic conditions;
- the level of capital expenditures we make;
- the restrictions contained in our debt agreements and debt service requirements;
- fluctuations in our working capital needs;
- the cost of acquisitions, if any; and
- the amount, if any, of cash reserves established by our General Partner in its sole discretion.

In addition, our ability to pay the minimum quarterly distribution each quarter depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, not solely on profitability, which is affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

The interruption of distributions to us from our subsidiaries and joint ventures may affect our ability to satisfy our obligations and to make distributions to our partners.

We are a holding company with no material operations. Our only significant assets are the equity interests we own in our subsidiaries and joint ventures. As a result, we depend upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of their cash to us in order to meet our obligations and to allow us to make distributions to our partners. In addition, charter documents and other agreements governing our joint ventures may restrict or limit the occurrence and amount of distributions to us under certain circumstances.

Expanding our natural gas gathering business by constructing new pipelines and compression facilities subjects us to construction risks and risks that natural gas supplies will not be available upon completion of the new pipelines and cash flows from such capital projects may not be immediate.

We engage in several construction and expansion projects involving existing and new facilities that require significant capital expenditures, which may exceed our estimates. We intend to expand the capacity of our existing natural gas gathering systems through the construction of additional facilities. Generally, we may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. As a result, there is the risk that new facilities may not be able to attract enough natural gas to achieve our expected investment return, which could adversely affect our financial position or results of operations. Additionally, operating cash flow from a particular project may not be realized until a period of time after its completion or at expected levels. Construction and expansion projects may occur over an extended period of time. If we experience unanticipated or extended delays in generating operating cash flow from these projects, we may be required to reduce or reprioritize our capital budget, sell non-core assets, access the capital markets or decrease or limit distributions to unitholders in order to meet our capital requirements.

Our tariff rates are subject to review and possible adjustment by federal and state regulators, which could have a material adverse effect on our financial condition and results of operations.

The Federal Energy Regulatory Commission ("FERC"), pursuant to the Interstate Commerce Act of 1887, as amended, regulates the tariff rates for our interstate common carrier pipeline operations. To be lawful under that Act, interstate tariff rates, terms and conditions of service must be just and reasonable and not unduly discriminatory, and must be on file with FERC. In addition, pipelines may not confer any undue preference upon any shipper. Shippers may protest, and the FERC may investigate, the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months. It can also require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful. The FERC and interested parties can also challenge tariff rates that have become final and effective. Because of the complexity of rate making, the lawfulness of any rate is never assured.

The FERC uses prescribed rate methodologies for approving regulated tariff rates for transporting crude oil and refined products. Our interstate tariff rates are either market-based or derived in accordance with the FERC's indexing methodology, which currently allows a pipeline to increase its rates by a percentage linked to the producer price index for finished goods. These methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting increased costs. Changes in the FERC's approved methodology for approving rates could adversely affect us. Adverse decisions by the FERC in approving our regulated rates could adversely affect our cash flow. Challenges to our tariff rates could be filed with the FERC.

The intrastate liquids pipeline transportation services we provide are subject to various state laws and regulations that apply to the rates we charge and the terms and conditions of the services we offer. Although state regulation typically is less onerous than FERC regulation, the rates we charge and the provision of our services may be subject to challenge.

Although our natural gas gathering systems are generally exempt from FERC regulation under the Natural Gas Act of 1938, FERC regulation still significantly affects our natural gas gathering business. In recent years, the FERC has pursued pro-competition policies in its regulation of interstate natural gas pipelines. If the FERC does not continue this approach, it could have an adverse effect on the rates we are able to charge in the future. In addition, our natural gas gathering operations could be adversely affected in the future should they become subject to the application of federal regulation of rates and services. Additional rules and legislation pertaining to these matters are considered and adopted from time to time. We cannot predict what effect, if any, such regulatory changes and legislation might have on our operations, but we could be required to incur additional capital expenditures.

Our partnership status may be a disadvantage to us in calculating our cost of service for rate-making purposes.

In May 2005, the FERC issued a policy statement permitting the inclusion of an income tax allowance in the cost of service-based rates of a pipeline for partnership interests held by partners with an actual or potential income tax liability on public utility income, if the pipeline proves that the owner of the partnership interest has an actual or potential income tax liability. On December 16, 2005, the FERC issued its first significant case-specific oil pipeline review of the income tax allowance issue in another pipeline company's rate case. The FERC reaffirmed its new income tax allowance policy and directed the subject pipeline to provide certain evidence necessary for the pipeline to determine its income tax allowance. The new tax allowance policy and the December 16 order have been appealed to the United States Court of Appeals for the District of Columbia Circuit. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service. Depending upon how the policy statement on income tax allowances is applied in practice to pipelines organized as pass-through entities, and whether it is ultimately upheld or modified on judicial review, these decisions might adversely affect us.

Competition could adversely affect our operating results.

Our refined products and LPG transportation business competes with other pipelines in the areas where we deliver products. We also compete with trucks, barges and railroads in some of the areas we serve. Competitive pressures may adversely affect our tariff rates or volumes shipped. The crude oil gathering and marketing business is characterized by thin margins and intense competition for supplies of crude oil at the wellhead. A decline in domestic crude oil production has intensified competition among gatherers and marketers. Our crude oil transportation business competes with common carriers and proprietary pipelines owned and operated by major oil companies, large independent pipeline companies and other companies in the areas where our pipeline systems deliver crude oil and natural gas liquids.

New supplies of natural gas are necessary to offset natural declines in production from wells connected to our gathering system and to increase throughput volume, and we encounter competition in obtaining contracts to gather natural gas supplies. Competition in natural gas gathering is based in large part on reputation, efficiency, system reliability, gathering system capacity and price arrangements. Our key competitors in the gas gathering segment include independent gas gatherers and major integrated energy companies. Alternate gathering facilities are available to producers we serve, and those producers may also elect to construct proprietary gas gathering systems. If the production delivered to our gathering system declines, our revenues from such operations will decline.

Our business requires extensive credit risk management that may not be adequate to protect against customer nonpayment.

Risks of nonpayment and nonperformance by customers are a major consideration in our businesses. Our credit procedures and policies may not be adequate to fully eliminate customer credit risk. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures. We utilize letters of credit and guarantees for certain of our receivables. However, these procedures and policies do not fully eliminate customer credit risk.

Our crude oil marketing business involves risks relating to product prices.

Our crude oil operations subject us to pricing risks as we buy and sell crude oil for delivery on our crude oil pipelines. These are the risks that price relationships between delivery points, classes of products or delivery periods will change after our initial purchases and before physical delivery of the crude oil.

Our pipelines are dependent on their interconnections with other pipelines to reach their destination markets.

Decreased throughput on interconnected pipelines due to testing, line repair and reduced pressures could result in reduced throughput on our pipeline systems. Such reduced throughput may adversely impact our profitability.

Reduced demand could affect shipments on the pipelines.

Our products pipeline business depends in large part on the demand for refined products and LPGs in the markets served by our pipelines. Reductions in that demand adversely affect our pipeline business. Market demand varies based upon the different end uses of the products we ship. We cannot predict the impact of future fuel conservation measures, alternate fuel requirements, government regulation or technological advances in fuel economy and energy-generation devices, all of which could reduce the demand for refined petroleum products and LPGs in the areas we serve. Demand for gasoline, which has in recent years accounted for approximately forty percent of our refined products transportation revenues, depends upon price, prevailing economic conditions and demographic changes in the markets we serve. Weather conditions, government policy and crop prices affect the demand for refined products used in agricultural operations. Demand for jet fuel, which has in recent years accounted for approximately twenty percent of our refined products revenues, depends on prevailing economic conditions and military usage. Propane deliveries are generally sensitive to the weather and meaningful year-to-year variances have occurred and will likely continue to occur.

Our gathering system profits and cash flow depend on the volumes of natural gas produced from the fields served by our gathering systems and are subject to factors beyond our control.

Regional production levels drive the volume of natural gas gathered on our systems. We cannot influence or control the operation or development of the gas fields we serve. Production levels may be affected by:

- the absolute price of, volatility in the price of, and market demand for natural gas;
- changes in laws and regulations, particularly with regard to taxes, denial of reduced well density spacing, safety and protection of the environment;
- the depletion rates of existing wells;
- adverse weather and other natural phenomena;
- the availability of drilling and service rigs; and
- industry changes, including the effect of consolidations or divestitures.

Our gathering systems are connected to natural gas reserves and wells, from which the production will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on our gathering systems, we must continually compete for and obtain new natural gas supplies. Our ability to obtain additional sources of natural gas depends in part on the level of successful drilling activity near our gathering systems, which depends on a number of factors, including energy prices, over which we have no control.

The use of derivative financial instruments could result in material financial losses by us.

We historically have sought to limit a portion of the adverse effects resulting from changes in commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms from time to time. To the extent that we hedge our commodity price and interest rate exposures, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though monitored by management, hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is imperfect, or hedging policies and procedures are not followed.

Our pipeline integrity program may impose significant costs and liabilities on us.

The U.S. Department of Transportation issued final rules (effective March 2001 with respect to hazardous liquid pipelines and February 2004 with respect to natural gas pipelines) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines and take measures to protect pipeline segments located in what the rules refer to as "high consequence areas." The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. At this time, we cannot predict the ultimate costs of compliance with this rule because those costs will depend on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing that is required by the rule. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Our operations are subject to governmental laws and regulations relating to the protection of the environment and safety which may expose us to significant costs and liabilities.

Our facilities are subject to multiple environmental obligations and potential liabilities under a variety of federal, state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges, and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could influence our results of operations. If an accidental leak, spill or release of hazardous substances occurs at any facilities that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held jointly and severally liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. Any or all of this could materially affect our results of operations and cash flows. We currently own or lease, and have owned or

leased, many properties that have been used for many years to terminal or store crude oil, petroleum products or other chemicals. Owners, tenants or users of these properties may have disposed of or released hydrocarbons or solid wastes on or under them. Additionally, some sites we operate are located near current or former refining and terminaling operations. There is a risk that contamination has migrated from those sites to ours.

Further, we cannot ensure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have material adverse effect on our business, financial position, results of operations and cash flows.

Various state and federal governmental authorities including the U.S. Environmental Protection Agency, the Bureau of Land Management, the Department of Transportation and the Occupational Safety and Health Administration have the power to enforce compliance with these regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Liability may be incurred without regard to fault under CERCLA, RCRA, and analogous state laws for the remediation of contaminated areas. Private parties, including the owners of properties through which our pipeline systems pass, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage.

Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage in the event an environmental claim is made against us. Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental regulations might adversely affect our products and activities, including storage, transportation and construction and maintenance activities, as well as waste management and air emissions. Federal and state agencies also could impose additional safety requirements, any of which could affect our profitability.

Contamination resulting from spills or releases of petroleum products is an inherent risk within the petroleum pipeline industry. While the costs of remediating groundwater contamination are generally site-specific, such costs can vary substantially and may be material.

Terrorist attacks aimed at our facilities could adversely affect our business.

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scale. Since the September 11th attacks, the United States government has issued warnings that energy assets, specifically our nation's pipeline infrastructure, may be the future target of terrorist organizations. These developments have subjected our operations to increased risks. Any future terrorist attack on our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, our operations and financial results could be adversely affected.

Our operations are subject to the many hazards inherent in the transportation of refined petroleum products, LPGs, NGLs, petrochemicals, and crude oil; the gathering, compressing, and treating of natural gas, including ruptures, leaks and fires. These risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. We are not fully insured against all risks incident to our business, including environmental accidents that might occur, and market conditions have caused premiums and deductibles for some of our insurance policies to increase substantively. If a significant accident or event occurs that is not fully insured, it could adversely affect our financial position or results of operations.

We depend on the leadership and involvement of our key personnel for the success of our business.

We depend on the leadership and involvement of our key personnel to identify and develop business opportunities and make strategic decisions. Our president and chief executive officer was elected in April 2006, our chief financial officer was elected in January 2006, and our general counsel was elected in March 2006. Our president and chief executive officer has over 35 years of relevant experience and our chief financial officer and general counsel each have approximately 20 years of relevant experience. While retention plans are in place for certain senior executives, any future unplanned departures could have a material adverse effect on our business, financial condition and results of operations. Legacy senior executives have compensation agreements in place but new officers may not be party to any compensation agreements.

Risks Relating to Our Units as a Result of Our Partnership Structure

We may issue additional limited partnership interests, diluting existing interests of unitholders and benefiting our General Partner.

Our partnership agreement allows us to issue additional Units and other equity securities without unitholder approval. These additional securities may be issued to raise cash or acquire additional assets or businesses or for other partnership purposes. Our partnership agreement does not limit the number of Units and other equity securities we may issue. If we issue additional Units or other equity securities, the proportionate partnership interest and voting power of our existing unitholders will decrease and the ratio of taxable income to distributions may increase. The issuance could negatively affect the amount of cash distributed to unitholders and the market price of our Units.

Cost reimbursements and fees due our General Partner and its affiliates may be substantial and will reduce our cash available for distribution to holders of our Units.

Prior to making any distribution on our Units, we will reimburse our General Partner and its affiliates, including EPCO and the officers and directors of our General Partner, for expenses they incur on our behalf. The reimbursement of expenses could adversely affect our ability to pay cash distributions to holders of our Units. Under our partnership agreement, our General Partner has sole discretion to determine the amount of these expenses. Under the administrative services agreement pursuant to which EPCO provides various services to us, we are obligated to pay EPCO for all direct and indirect costs and expenses associated with services it provides that relate to our business or activities. In addition, our General Partner and its affiliates may provide other services to us for which we will be charged fees as determined by our General Partner.

Our General Partner and its affiliates may have conflicts with our partnership.

The directors and officers of our General Partner and its affiliates (including EPCO and other affiliates of EPCO) have duties to manage the General Partner in a manner that is beneficial to its member. At the same time, the General Partner has duties to manage us in a manner that is beneficial to us. EPCO also controls another publicly

traded partnership, Enterprise, that engages in similar lines of business. We have significant business relationships with Enterprise and EPCO and other entities controlled by Dan L. Duncan. Therefore, our General Partner's duties to us may conflict with the duties of its officers and directors to its member. Provisions of our partnership agreement, the partnership agreements for each of our operating partnerships and/or the administrative services agreement provide for a standard of care that may allow our General Partner to approve actions in the context of possible conflicts, which under state law a corporation would be required to analyze with greater scrutiny. Possible conflicts may include, among others, the following:

- decisions of our General Partner regarding the amount and timing of cash expenditures, borrowings and issuances of additional Units or other equity securities that can affect the amount of cash that is available for distribution to unitholders and the amount of payments we make to our General Partner with respect to its increasing percentage interests in our distributions;
- decisions of our General Partner regarding our acquisitions, expansions or business strategy, which may provide benefits to the General Partner and its affiliates;
- under our partnership agreement, it is not a breach of our General Partner's fiduciary duties for affiliates of our General Partner to engage in activities that compete with us;
- the directors and officers of our General Partner are allowed to resolve conflicts of interest involving us and EPCO and its affiliates and are allowed to take into account the interests of parties other than us, such as EPCO and its affiliates, including Enterprise, in resolving these conflicts of interest;
- any resolution of a conflict of interest by the directors and officers of our General Partner not made in bad faith and that is fair and reasonable to us is binding on the partners and will not constitute a breach of our partnership agreement;
- we do not have any employees and we rely solely on employees of EPCO;
- our partnership agreement does not restrict the General Partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf; and
- the directors and officers of our General Partner and EPCO control the enforcement of obligations owed to us by our General Partner, EPCO and its affiliates.

Unitholders have limited voting rights and control of management.

Our General Partner manages and controls our activities and the activities of our operating partnerships. Unitholders have no right to elect the General Partner or the directors of the General Partner on an annual or other ongoing basis. However, if the General Partner resigns or is removed, its successor may be elected by holders of a majority of the Units. Unitholders may remove the General Partner only by a vote of the holders of at least $66\frac{2}{3}\%$ of the Units and only after receiving state regulatory approvals required for the transfer of control of a public utility. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations. As a result, unitholders will have limited influence on matters affecting our operations, and third parties may find it difficult to gain control of us or influence our actions.

EPCO's employees, including some of our executive officers and directors, may be subjected to conflicts in managing our business and the allocation of time and compensation costs between our business and the business of EPCO and its other affiliates.

Certain of our executive officers and three of our directors are also officers and/or directors of EPCO and other affiliates of EPCO, including Enterprise. These relationships may create conflicts of interest regarding corporate opportunities and other matters, and the resolution of any such conflicts may not always be in our or our unitholders' best interests. In addition, these overlapping executive officers and directors allocate their time among us, EPCO and other affiliates of EPCO. These officers and directors face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

We have entered into an administrative services agreement that governs business opportunities among entities controlled by our General Partner, including us ("TEPPCO Companies"), entities controlled by the general partners of Enterprise GP Holdings L.P. and Enterprise, including Enterprise GP Holdings and Enterprise ("Enterprise Companies"), and EPCO and its other affiliates. Under the administrative services agreement, we have no obligation to present any business opportunity offered to or discovered by us to the Enterprise Companies, and they are not obligated to present business opportunities that are offered to or discovered by them to us. However, the agreement requires that business opportunities offered to or discovered by EPCO, which controls both the TEPPCO Companies and the Enterprise Companies, be offered first to certain Enterprise Companies before they may be pursued by EPCO and its other affiliates or offered to us.

Under the administrative services agreement, EPCO and its affiliates provide all administrative, operational and other services, including employee support, for us and our General Partner. Some of the EPCO employees providing these services to us may also have duties and responsibilities related to EPCO and its other affiliates, including Enterprise. The services performed by these shared personnel will generally be limited to non-commercial functions, including but not limited to human resources, information technology, financial and accounting services and legal services. EPCO may encounter conflicts of interest in allocating the available time and employee costs of shared personnel between us and other EPCO affiliates.

We do not have an independent compensation committee, and aspects of the compensation of our executive officers and other key employees, including base salary, are not reviewed or approved by our independent directors. The determination of executive officer and key employee compensation could involve conflicts of interest resulting in economically unfavorable arrangements for us.

Our General Partner has a limited call right that may require unitholders to sell their Units at an undesirable time or price.

If at any time persons other than our General Partner and its affiliates own less than 15% of the Units then outstanding, our General Partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining Units held by unaffiliated persons at a price not less than the then-current market price. As a result, unitholders may be required to sell their Units at an undesirable time or price and may therefore not receive any return on their investment. They may also incur a tax liability upon a sale of their Units.

Our unitholders may not have limited liability if a court finds that limited partner actions constitute control of our business.

Under Delaware law, our General Partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those of our contractual obligations that are expressly made without recourse to our General Partner. Further, unitholders could be held liable for our obligations to the same extent as a General Partner if a court determined that the right of limited partners to remove our General Partner or to take other action under our partnership agreement constituted participation in the ""control" of our business.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a limited partner may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

The credit and risk profile of our General Partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of the general partner or owners of a general partner may be factors in credit evaluations of a master limited partnership. This is because the general partner can exercise significant influence over the business activities of the partnership, including its cash distribution and acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of the general partner and its

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owners, including the degree of their financial leverage and their dependence on cash flow from the partnership to service their indebtedness.

Entities controlling the owner of our General Partner have significant indebtedness outstanding and are dependent principally on the cash distributions from the General Partner and limited partner equity interests in us to service such indebtedness. Any distributions by us to such entities will be made only after satisfying our then current obligations to our creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us from our General Partner and the entities that control our General Partner, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of the entities that control our General Partner were viewed as substantially lower or more risky than ours.

Control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our General Partner or DFI from transferring all or a portion of their respective ownership interest in our General Partner or DFI to a third party. The new owners of our General Partner or DFI would then be in a position to replace the board of directors and officers of our General Partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. The amount of cash available for distribution to you would be substantially reduced if the Internal Revenue Service, or IRS, treats us as a corporation or we become subject to a material amount of entity-level taxation for state tax purposes.

The anticipated after-tax economic benefit of an investment in the Units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35% and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, our treatment as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our Units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level federal income taxation. Our partnership agreement currently provides that if a law is enacted that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, the minimum quarterly distribution amount and the target distribution level will be adjusted to reflect the impact of that law on us, including any related imposition of state and local income taxes. A unitholder vote on a number of proposed amendments to our partnership agreement, including an amendment that would permit our General Partner to similarly adjust the minimum quarterly distribution amount and the target distribution level for entity-level taxation arising from a change in the interpretation of existing law or the enactment of a state or local law subjecting us to entity-level taxation, is currently pending.

In addition, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we will be subject to a new entity-level tax on the portion of our income generated in Texas beginning in 2007. Specifically, the Texas margin tax will

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be imposed at a maximum effective rate of 0.7% of our gross income apportioned to Texas. Imposition of such tax on us by Texas, or any other state, will reduce the cash available for distribution to you.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our Units, and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our Units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our General Partner because the costs will reduce our cash available for distribution.

You may be required to pay taxes on income from us even if you do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the tax liability that results from that income.

Tax gain or loss on disposition of Units could be more or less than expected.

If you sell your Units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those Units. Prior distributions to you in excess of the total net taxable income you were allocated for a Unit, which decreased your tax basis in that Unit, will, in effect, become taxable income to you if the Unit is sold at a price greater than your tax basis in that Unit, even if the price is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. If you sell your Units, you may incur a tax liability in excess of the amount of cash you receive from the sale. If the IRS successfully contests some positions we take, unitholders could recognize more gain on the sale of Units than would be the case under those positions, without the benefit of decreased income in prior years.

Tax-exempt entities and foreign persons face unique tax issues from owning Units that may result in adverse tax consequences to them.

Investment in Units by tax-exempt entities, such as individual retirement accounts (“IRAs”), other retirement plans, and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person you should consult your tax advisor before investing in our Units.

We treat each purchaser of our Units as having the same tax benefits without regard to the actual Units purchased. The IRS may challenge this treatment, which could adversely affect the value of the Units.

We take depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. We take these positions for a number of reasons, including the fact that we cannot match transferors and transferees of Units. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from the sale of Units and could have a negative impact on the value of our Units or result in audit adjustments to your tax returns.

Unitholders may be subject to state and local taxes and return filing requirements.

In addition to federal income taxes, you will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if you do not live in any of those jurisdictions. You will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. Our operating subsidiaries own assets and do business in Alabama, Arkansas, Colorado, Illinois, Indiana, Kansas, Kentucky, Louisiana, Mississippi, Missouri, Montana, Nebraska, New Mexico, New York, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Dakota, Texas, Utah, West Virginia and Wyoming. Each of these states, other than South Dakota, Texas and Wyoming currently imposes a personal income tax and many impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, foreign, state and local tax returns.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income. If this occurs, you will be allocated an increased amount of federal taxable income for the year in which we are considered to be terminated as a percentage of the cash distributed to you with respect to that period.

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).
3.3	Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated March 31, 2000 (Filed as Exhibit 3.3 to Form 10-Q/A of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
3.4	Amendment to Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated March 22, 2005 (Filed as Exhibit 3.4 to Form 10-Q/A of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
3.5	Amendment to Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated June 15, 2006, but effective as of February 24, 2005 (Filed as Exhibit 3.1 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on June 16, 2006.
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+*	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan Notice of 2006 Award.
10.2+*	Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan Notice of 2006 Award.
10.3	Third Amendment to Amended and Restated Credit Agreement, dated as of July 31, 2006, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders and as the LC Issuing Bank, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A., and The Royal Bank of Scotland Plc, as Co-Documentation Agents (Filed as Exhibit 10.3 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.4	Amended and Restated Partnership Agreement of Jonah Gas Gathering Company dated as of August 1, 2006 (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.5	Contribution Agreement among TEPPCO GP, Inc., TEPPCO Midstream Companies, L.P. and Enterprise Gas Processing, LLC dated as of August 1, 2006 (Filed as Exhibit 10.2 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 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 Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2**	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

** Furnished herewith pursuant to Item 601(b)-(32) of Regulation S-K.

+ A management contract or compensation plan or arrangement.

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.

By: /s/ JERRY E. THOMPSON
Jerry E. Thompson,
President and Chief Executive Officer of
Texas Eastern Products Pipeline Company, LLC, General Partner

Date: August 4, 2006

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

Date: August 4, 2006

Exhibit 10.1

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC
2000 LONG TERM INCENTIVE PLAN
NOTICE OF 2006 AWARD

Grantee:

Effective Date: January 1, 2006

1. ***Grant.*** Pursuant to the Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan (the "Plan"), Texas Eastern Products Pipeline Company, LLC ("TEPPCO") hereby grants you, as of the Effective Date, Long Term Incentive Units (the "Award") with respect to the Performance Period beginning on January 1, 2006, and ending on December 31, 2008.

2. ***Vested Interest.*** At the end of the Performance Period, the Chairman of the Board of Directors of Texas Eastern Products Pipeline Company, LLC shall determine your Vested Interest in the Award as follows: (A) minus (B), multiplied by (C), where (A) is the Economic Value Added for the Performance Period, (B) is the Benchmark, and (C) is .00000305%. The Benchmark is $85,776,000.

3. ***Automatic Replacement of Award with an EPCO Award.*** Notwithstanding anything in this Notice to the contrary, effective upon a consolidation, merger or combination of the businesses of Enterprise Product Partners, L.P. and TEPPCO Partners, L.P., (a "Business Combination"), as determined by EPCO, in its discretion, prior to the end of the Performance Period, your Award under this Notice automatically shall terminate in full without payment. Upon such Business Combination, you will be granted either Restricted Units or Phantom Units (as determined by EPCO in its discretion) under an EPCO, Inc. long term incentive plan (the "EPCO Grant"). The EPCO Grant will be equal to the number of Long Term Incentive Units granted to you under this Notice, multiplied by the quotient of (i) the closing sales price of a TEPPCO Common Unit on the effective date of the Business Combination divided by (ii) the closing sales price of an Enterprise Products Common Unit on that date. The EPCO Grant will provide full vesting at the end of its four-year vesting period provided you are an employee of EPCO or its affiliates on that date. It will also provide for earlier vesting upon certain qualifying terminations of employment prior to the end of the vesting period consistent with the form of grant agreement adopted by EPCO in general with respect to such EPCO long-term incentive plan. The four-year vesting period for the EPCO Grant will begin on the date you received your 2006 Award under this Notice.

4. ***Withholding of Taxes.*** EPCO may withhold from all payments to be paid to you pursuant to this Notice all taxes that, by applicable federal, state, local or other law of any applicable jurisdiction, it is required to withhold.

5. ***Amendment.*** This Notice may be amended or modified by TEPPCO at any time, but no change that is materially adverse to you may be made without your written consent.

6. ***Assignment by TEPPCO.*** TEPPCO may assign this Notice to any successor of TEPPCO or to any Affiliate of TEPPCO, including EPCO.

7. ***Governing Law.*** The validity, interpretation, construction and enforceability of this Notice shall be governed by the laws of the State of Texas without giving effect to a choice or conflict of law provision or rule of such state.

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8. ***Severability.*** If a court of competent jurisdiction determines that any provision of this Notice is invalid or unenforceable, then the validity or enforceability of this provision shall not affect the validity or enforceability of any other provision of this Notice, and all other provisions shall remain in full force and effect.

9. ***Plan.*** A copy of the Plan is attached hereto and incorporated by reference herein. Terms that are not specifically defined in this Notice shall have the meanings ascribed to them in the Plan. In the event of any conflict between the terms of this Notice and the Plan, the Plan shall govern.

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC

By: ______________________________
Name: ______________________________
Title: ______________________________

GRANTEE:

Name: ______________________________

Exhibit 10.2

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC
2005 PHANTOM UNIT PLAN
NOTICE OF 2006 AWARD

Grantee: [ ]

Effective Date: January 1, 2006

1. ***Grant.*** Pursuant to the Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan (the "Plan"), Texas Eastern Products Pipeline Company, LLC ("TEPPCO") hereby grants you, as of the Effective Date, Phantom Units (the "Award") with respect to the Performance Period beginning on January 1, 2006, and ending on December 31, 2008.

2. ***Performance Goal.*** The Performance Goal applicable to this Award shall be the achievement of a cumulative EBITDA for the Performance Period of an amount equal to the sum of the EBITDA targets established by the Board of Directors for each of the calendar years during the Performance Period.

3. ***Vested Percentage.*** At the end of the Performance Period, the Chief Executive Officer of TEPPCO shall determine your Vested Interest after determining the extent to which the Performance Goal has been achieved. Subject to the following, your Vested Percentage will be equal to the percentage of the Target Level of Performance that is achieved during the Performance Period, but in no event shall it be greater than 150%. However, the Chief Executive Officer has the unrestricted discretion to reduce your Vested Percentage below the Target Level of Performance achieved for any reason(s) he/she deems appropriate. Further, if the Chief Executive Officer determines that less than 50% of the Target Level of Performance was achieved during the Performance Period, your Vested Percentage will be zero.

4. ***Automatic Replacement of Phantom Units with an EPCO Award.*** Notwithstanding anything in this Notice to the contrary, effective upon a consolidation, merger or combination of the businesses of Enterprise Product Partners, L.P. and TEPPCO Partners, L.P., (a "Business Combination"), as determined by EPCO, in its discretion, prior to the end of the Performance Period, your Award under this Notice automatically shall terminate in full without payment. Upon such Business Combination, you will be granted either Restricted Units or Phantom Units (as determined by EPCO in its discretion) under an EPCO, Inc. long term incentive plan (the "EPCO Grant"). The EPCO Grant will be equal to the number of Phantom Units granted to you under this Notice, multiplied by the quotient of (i) the closing sales price of a TEPPCO Common Unit on the effective date of the Business Combination divided by (ii) the closing sales price of an Enterprise Products Common Unit on that date. The EPCO Grant will provide full vesting at the end of its four-year vesting period provided you are an employee of EPCO or its affiliates on that date. It will also provide for earlier vesting upon certain qualifiying terminations of employment prior to the end of the vesting period consistent with the form of grant agreement adopted by EPCO in general with respect to such EPCO long-term incentive plan. The four-year vesting period for the EPCO Grant will begin on the date you received your 2005 Award under this Notice.

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4. ***Withholding of Taxes.*** EPCO may withhold from all payments to be paid to you pursuant to this Notice all taxes that, by applicable federal, state, local or other law of any applicable jurisdiction, it is required to withhold.

5. ***Amendment.*** This Notice may be amended or modified by TEPPCO at any time, but no change that is materially adverse to you may be made without your written consent.

6. ***Assignment by TEPPCO.*** TEPPCO may assign this Notice to any successor of TEPPCO or to any Affiliate of TEPPCO, including EPCO.

7. ***Governing Law.*** The validity, interpretation, construction and enforceability of this Notice shall be governed by the laws of the State of Texas without giving effect to a choice or conflict of law provision or rule of such state.

8. ***Severability.*** If a court of competent jurisdiction determines that any provision of this Notice is invalid or unenforceable, then the validity or enforceability of this provision shall not affect the validity or enforceability of any other provision of this Notice, and all other provisions shall remain in full force and effect.

9. ***Plan.*** A copy of the Plan is attached hereto and incorporated by reference herein. Terms that are not specifically defined in this Notice shall have the meanings ascribed to them in the Plan. In the event of any conflict between the terms of this Notice and the Plan, the Plan shall govern.

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC

By: ____________________
Name: ____________________
Title: ____________________

GRANTEE:

Name: ____________________

Exhibit 12.1

Statement of Computation of Ratio of Earnings to Fixed Charges

	2002	2003	2004	2005	Six Months Ended June 30, 2006
			(in thousands)		
Earnings					
Income From Continuing Operations *	105,882	104,958	112,658	138,639	79,910
Fixed Charges	73,381	93,294	80,695	93,414	49,088
Distributed Income of Equity Investments	30,938	28,003	47,213	37,085	16,297
Capitalized Interest	(4,345)	(5,290)	(4,227)	(6,759)	(6,417)
Total Earnings	205,856	220,965	236,339	262,379	138,878
Fixed Charges					
Interest Expense	66,192	84,250	72,053	81,861	40,341
Capitalized Interest	4,345	5,290	4,227	6,759	6,417
Rental Interest Factor	2,844	3,754	4,415	4,794	2,330
Total Fixed Charges	73,381	93,294	80,695	93,414	49,088
Ratio: Earnings / Fixed Charges	2.81	2.37	2.93	2.81	2.83

* Excludes discontinued operations, gain on sale of assets and undistributed equity earnings.

Exhibit 31.1

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, Jerry E. Thompson, certify that:

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

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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 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 report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter 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.

August 4, 2006

/s/ JERRY E. THOMPSON
Jerry E. Thompson
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, William G. Manias, certify that:

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

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

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

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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 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 report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter 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.

August 4, 2006

/s/ WILLIAM G. MANIAS
William G. Manias
Vice President and 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 June 30, 2006 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Jerry E. Thompson, President and Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC, the general partner 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/ JERRY E. THOMPSON

Jerry E. Thompson
President and Chief Executive Officer
Texas Eastern Products Pipeline Company, LLC, General Partner

August 4, 2006

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 June 30, 2006 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, William G. Manias, Vice President and Chief Financial Officer of Texas Eastern Products Pipeline Company, LLC, the general partner 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/ WILLIAM G. MANIAS

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

August 4, 2006

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.