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

FORM 10-Q

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

For the quarterly period ended September 30, 2008

OR

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

For the transition period from _____ to _____.

Commission File No. 1-10403

TEPPCO Partners, L.P.

(Exact name of Registrant as specified in its charter)

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

1100 Louisiana Street, Suite 1600
Houston, Texas 77002
(Address of principal executive offices, including zip code)

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑	Accelerated Filer o
Non-accelerated Filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. Limited Partner Units outstanding as of November 3, 2008: 104,524,501

TEPPCO PARTNERS, L.P.

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PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements.***

TEPPCO PARTNERS, L.P.

UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	September 30, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 55	$ 23
Accounts receivable, trade (net of allowance for doubtful accounts of $1,525 and $125)	1,715,504	1,381,871
Accounts receivable, related parties	6,410	6,525
Inventories	170,290	80,299
Other	78,541	47,271
Total current assets	1,970,800	1,515,989
Property, plant and equipment, at cost (net of accumulated depreciation of $651,936 and $582,225)	2,372,694	1,793,634
Equity investments	1,191,377	1,146,995
Intangible assets	214,370	164,681
Goodwill	106,404	15,506
Other assets	129,980	113,252
Total assets	$ 5,985,625	$ 4,750,057
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Senior notes	$ --	$ 353,976
Accounts payable and accrued liabilities	1,809,746	1,413,447
Accounts payable, related parties	38,940	38,980
Accrued interest	49,327	35,491
Other accrued taxes	29,970	20,483
Other	50,608	84,848
Total current liabilities	1,978,591	1,947,225
Long-term debt:		
Senior notes	1,714,463	721,545
Junior subordinated notes	299,565	299,538
Other long-term debt	324,717	490,000
Total long-term debt	2,338,745	1,511,083
Other liabilities and deferred credits	30,138	27,122
Commitments and contingencies		
Partners' capital:		
Limited partners' interests:		
Limited partner units (104,367,201 and 89,849,132 units outstanding)	1,788,146	1,394,812
Restricted limited partner units (157,300 and 62,400 units outstanding)	1,059	338
General partner's interest	(100,709)	(87,966)
Accumulated other comprehensive loss	(50,345)	(42,557)
Total partners' capital	1,638,151	1,264,627
Total liabilities and partners' capital	$ 5,985,625	$ 4,750,057

See Notes to Unaudited Condensed Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

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

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
Operating revenues:				
Sales of petroleum products	$ 4,025,641	$ 2,455,695	$ 10,676,786	$ 6,238,927
Transportation – Refined products	42,203	48,123	123,602	126,976
Transportation – LPGs	16,335	16,735	68,589	69,535
Transportation – Crude oil	15,759	12,332	48,491	32,702
Transportation – NGLs	12,560	12,023	38,218	34,062
Transportation – Marine	46,018	--	119,584	--
Gathering – Natural gas	14,620	15,429	42,822	46,289
Other	32,608	20,320	76,603	60,031
Total operating revenues	4,205,744	2,580,657	11,194,695	6,608,522
Costs and expenses:				
Purchases of petroleum products	3,989,484	2,426,692	10,571,817	6,141,630
Operating expense	80,868	45,375	201,210	134,458
Operating fuel and power	25,954	15,060	76,401	45,163
General and administrative	10,846	7,396	30,620	24,158
Depreciation and amortization	32,071	26,486	92,234	77,735
Taxes – other than income taxes	6,662	4,931	19,759	15,149
Gains on sales of assets	(1)	(2)	(1)	(18,653)
Total costs and expenses	4,145,884	2,525,938	10,992,040	6,419,640
Operating income	59,860	54,719	202,655	188,882
Other income (expense):				
Interest expense – net	(34,301)	(26,901)	(105,906)	(71,897)
Gain on sale of ownership interest in Mont Belvieu Storage Partners, L.P.	--	(20)	--	59,628
Equity earnings	22,133	19,059	63,212	54,856
Interest income	289	454	880	1,241
Other income – net	106	306	905	1,085
Income before provision for income taxes	48,087	47,617	161,746	233,795
Provision for income taxes	1,056	(14)	2,894	213
Net income	$ 47,031	$ 47,631	$ 158,852	$ 233,582
Net Income Allocation:				
Limited Partner’s interest in net income	$ 39,007	$ 39,656	$ 132,111	$ 195,106
General Partner interest in net income	8,024	7,975	26,741	38,476
Total net income allocated	$ 47,031	$ 47,631	$ 158,852	$ 233,582
Basic and diluted net income per Limited Partner Unit	$ 0.40	$ 0.44	$ 1.39	$ 2.17
Weighted average Limited Partner Units outstanding	97,316	89,868	95,145	89,835

See Notes to Unaudited Condensed Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

UNAUDITED CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Net income	$ 47,031	$ 47,631	$ 158,852	$ 233,582
Other comprehensive income (loss):				
Cash flow hedges:				
Change in fair values of interest rate cash flow hedges and treasury locks	(27)	(2,528)	(23,254)	(1,016)
Changes in fair values of crude oil cash flow hedges	23,370	(3,216)	15,466	(3,369)
Total cash flow hedges	23,343	(5,744)	(7,788)	(4,385)
Total other comprehensive income (loss)	23,343	(5,744)	(7,788)	(4,385)
Comprehensive income	$ 70,374	$ 41,887	$ 151,064	$ 229,197

See Notes to Unaudited Condensed Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands, except per Unit amounts)

	For the Nine Months Ended September 30, 2008	2007
Operating activities:		
Net income	$ 158,852	$ 233,582
Adjustments to reconcile net income to cash provided by operating activities:		
Deferred income taxes	5	(656)
Depreciation and amortization	92,234	77,735
Amortization of deferred compensation	1,257	514
Amortization in interest expense	1,461	(2,369)
Earnings in equity investments	(63,212)	(54,856)
Distributions from equity investments	119,017	96,967
Gains on sales of assets	--	(18,653)
Gain on sale of ownership interest in Mont Belvieu Storage Partners, L.P.	--	(59,628)
Loss on early extinguishment of debt	8,689	--
Net effect of changes in operating accounts	(23,434)	(53,450)
Net cash provided by operating activities	294,869	219,186
Investing activities:		
Proceeds from sales of assets	--	27,771
Proceeds from sale of ownership interest	--	137,326
Purchase of assets	--	(12,733)
Increase in restricted cash	--	(2,877)
Cash used for business combinations	(351,866)	--
Investment in Centennial Pipeline LLC	--	(11,081)
Investment in Jonah Gas Gathering Company	(94,875)	(127,775)
Investment in Texas Offshore Port System	(8)	--
Acquisition of intangible assets	(317)	(2,500)
Cash paid for linefill on assets owned	(11,530)	(26,613)
Capital expenditures	(215,162)	(164,161)
Net cash used in investing activities	(673,758)	(182,643)
Financing activities:		
Proceeds from term credit facility	1,000,000	--
Repayments on term credit facility	(1,000,000)	--
Proceeds from revolving credit facility	1,852,567	805,250
Repayments on revolving credit facility	(2,017,850)	(918,250)
Repayment of debt assumed in Cenac acquisition	(63,157)	--
Redemption of 7.51% TE Products Senior Notes	(181,571)	--
Repayment of 6.45% TE Products Senior Notes	(180,000)	--
Issuance of Limited Partner Units, net	271,313	53
Issuance of senior notes	996,349	--
Issuance of Junior Subordinated Notes	--	299,517
Debt issuance costs	(9,857)	(3,750)
Settlement of treasury lock agreements	(52,098)	1,443
Payment for termination of interest rate swap	--	(1,235)
Distributions paid	(236,775)	(219,613)
Net cash provided by (used in) financing activities	378,921	(36,585)
Net change in cash and cash equivalents	32	(42)
Cash and cash equivalents, January 1	23	70
Cash and cash equivalents, September 30	$ 55	$ 28

See Notes to Unaudited Condensed Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED PARTNERS' CAPITAL
(Dollars in thousands, except Unit amounts)

	Outstanding Limited Partner Units	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive Loss	Total
Balance, December 31, 2007	89,911,532	$ (87,966)	$ 1,395,150	$ (42,557)	$ 1,264,627
Net income allocation	--	26,741	132,111	--	158,852
Issuance of units in connection with Cenac acquisition on February 1, 2008	4,854,899	--	186,558	--	186,558
Limited Partner Units issued in connection with Distribution Reinvestment Plan	205,288	--	6,773	--	6,773
Units issued in connection with Employee Unit Purchase Plan	16,502	--	570	--	570
Issuance of restricted units under 2006 LTIP	94,900	--	--	--	--
Issuance of Limited Partner Units, net	9,441,380	--	263,970	--	263,970
Cash distributions	--	(39,484)	(197,291)	--	(236,775)
Non-cash contribution	--	--	474	--	474
Amortization of equity awards	--	--	890	--	890
Changes in fair values of crude oil cash flow hedges	--	--	--	15,466	15,466
Changes in fair values of treasury locks	--	--	--	(23,254)	(23,254)
Balance, September 30, 2008	104,524,501	$ (100,709)	$ 1,789,205	$ (50,345)	$ 1,638,151

See Notes to Unaudited Condensed Consolidated Financial Statements.

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands.

NOTE 1. PARTNERSHIP ORGANIZATION AND BASIS OF PRESENTATION

Partnership Organization

TEPPCO Partners, L.P. (the “Partnership”), is a publicly traded Delaware limited partnership and our limited partner units (“Units”) are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “TPP”. As used in this Report, “we,” “us,” “our,” the “Partnership” and “TEPPCO” mean TEPPCO Partners, L.P. and, where the context requires, include our subsidiaries.

We operate through TE Products Pipeline Company, LLC (“TE Products”), TCTM, L.P. (“TCTM”) and TEPPCO Midstream Companies, LLC (“TEPPCO Midstream”), and beginning February 1, 2008, through TEPPCO Marine Services, LLC (“TEPPCO Marine Services”). Texas Eastern Products Pipeline Company, LLC (the “General Partner”), a Delaware limited liability company, serves as our general partner and owns a 2% general partner interest in us. We hold a 99.999% limited partner interest in TCTM, 99.999% membership interests in each of TE Products and TEPPCO Midstream and a 100% membership interest in TEPPCO Marine Services. TEPPCO GP, Inc. (“TEPPCO GP”), our subsidiary, holds a 0.001% general partner interest in TCTM and a 0.001% managing member interest in each of TE Products and TEPPCO Midstream.

Through May 6, 2007, our General Partner was owned by DFI GP Holdings L.P. (“DFIGP”), an affiliate of EPCO, Inc. (“EPCO”), a privately held company controlled by Dan L. Duncan. On May 7, 2007, DFIGP sold all of the membership interests in our General Partner, together with 4,400,000 of our Units, to Enterprise GP Holdings L.P. (“Enterprise GP Holdings”), a publicly traded partnership, also controlled indirectly by Dan L. Duncan. Mr. Duncan and certain of his affiliates, including Enterprise GP Holdings and Dan Duncan LLC, a privately held company controlled by him, control us, our General Partner and Enterprise Products Partners L.P. (“Enterprise Products Partners”) and its affiliates, including Duncan Energy Partners L.P. (“Duncan Energy Partners”). As of May 7, 2007, Enterprise GP Holdings owns and controls the 2% general partner interest in us and has the right (through its 100% ownership of our General Partner) to receive the incentive distribution rights associated with the general partner interest. Enterprise GP Holdings, DFIGP and other entities controlled by Mr. Duncan own 16,950,130 of our Units. Under an amended and restated administrative services agreement (“ASA”), EPCO performs 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.

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements reflect all adjustments that are, in the opinion of our management, of a normal and recurring nature and necessary for a fair statement of our financial position as of September 30, 2008, and the results of our operations and cash flows for the periods presented. The results of operations for the three months and nine months ended September 30, 2008, are not necessarily indicative of results of our operations for the full year 2008. The unaudited condensed consolidated financial statements have been prepared pursuant to the rules and regulations of the U.S. Securities and Exchange Commission (“SEC”). Certain information and note disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles (“GAAP”) have been condensed or omitted pursuant to those rules and regulations. You should read these interim financial statements in conjunction with our consolidated financial statements and notes thereto presented in the TEPPCO Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2007.

NOTE 2. GENERAL ACCOUNTING POLICIES AND RELATED MATTERS

Business Segments

We operate and report in four business segments:

- § pipeline transportation, marketing and storage of refined products, liquefied petroleum gases ("LPGs") and petrochemicals ("Downstream Segment");
- § gathering, pipeline transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals ("Upstream Segment");
- § gathering of natural gas, fractionation of natural gas liquids ("NGLs") and pipeline transportation of NGLs ("Midstream Segment"); and
- § marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges ("Marine Services Segment").

Our reportable segments offer different products and services and are managed separately because each requires different business strategies (see Note 13).

Our interstate pipeline 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, lubrication oils and specialty chemicals, NGLs, natural gas, asphalt, heavy fuel oil and other heated oil products in this Report, collectively, as "petroleum products" or "products."

Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling financial or equity interest, after the elimination of all intercompany accounts and transactions. We evaluate our financial interests in companies to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own.

If an investee is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50% and we exercise significant influence over the entity's operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the entity's operating and financial policies. In consolidation, we eliminate our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates to the extent such amounts are material and remain on our balance sheet (or those of our equity method investments) in inventory or similar accounts. Our investments in Seaway Crude Pipeline Company ("Seaway") and Centennial Pipeline LLC ("Centennial") are accounted for under the equity method of accounting, as we own 50% ownership interests in these entities and have 50% equal management with the other joint venture participants. Our investment in Texas Offshore Port System is accounted for under the equity method of accounting, as we own a 33% ownership interest in this entity and have equal voting rights with the other joint venture participants. Our investment in Jonah Gas Gathering Company ("Jonah") is accounted for under the equity method of accounting, as we have 50% equal management with the other participant, even though we own an approximate 80% economic interest in the partnership.

If our ownership interest in an entity does not provide us with either control or significant influence over the investee, we account for the investment using the cost method.

Environmental Expenditures

We accrue for environmental costs that relate to existing conditions caused by past operations, including conditions with assets we have acquired. Environmental costs include initial site surveys and environmental studies of potentially contaminated sites, costs for remediation and restoration of sites determined to be contaminated and ongoing monitoring costs, as well as damages and other costs, when estimable. We monitor the balance of accrued undiscounted environmental liabilities on a regular basis. We record liabilities for environmental costs at a specific site when our liability for such costs is probable and a reasonable estimate of the associated costs can be made. Adjustments to initial estimates are recorded, from time to time, to reflect changing circumstances and estimates based upon additional information developed in subsequent periods. Estimates of our ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation alternatives available and the evolving nature of environmental laws and regulations. None of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable. Expenditures to mitigate or prevent future environmental contamination are capitalized.

At September 30, 2008 and December 31, 2007, our accrued liabilities for environmental remediation projects totaled $7.1 million and $4.0 million, respectively. These amounts were derived from a range of reasonable estimates based upon studies and site surveys. Unanticipated changes in circumstances and/or legal requirements could result in expenses being incurred in future periods in addition to an increase in actual cash required to remediate contamination for which we are responsible.

Estimates

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

Recent Accounting Developments

The following information summarizes recently issued accounting guidance since those reported in our Annual Report on Form 10-K for the year ended December 31, 2007 that will or may affect our future financial statements.

In March 2008, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 161, *Disclosures about Derivative Instruments and Hedging Activities an – amendment of FASB Statement No. 133*. SFAS 161 changes the disclosure requirements for financial instruments and hedging activities with the intent to provide users of financial statements with an enhanced understanding of (i) how and why an entity uses financial instruments, (ii) how financial instruments and related hedged items are accounted for under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and its related interpretations and (iii) how financial instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 requires qualitative disclosures about objectives and strategies for using financial instruments, quantitative disclosures about fair value amounts of and gains and losses on financial instruments and disclosures about credit risk-related contingent features in financial instrument agreements. This statement has the same scope as SFAS 133, and accordingly applies to all entities. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. SFAS 161 only affects disclosure requirements; therefore, our adoption of this statement effective January 1, 2009 will not impact our financial position, results of operations or cash flows.

In March 2008, the Emerging Issues Task Force ("EITF"), reached consensus on EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*. This guidance prescribes the manner in which a master limited partnership ("MLP") should allocate and present earnings per unit using the two-class method set forth in SFAS No. 128, *Earnings per Share*. Under the two-class method, current period earnings are allocated to the general partner (including any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the MLP's partnership agreement. EITF 07-4 is effective for us on January 1, 2009. We do not believe that EITF 07-4 will have a material impact on our earnings per unit computations and disclosures.

In June 2008, FASB Staff Position ("FSP") No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, was issued. FSP EITF 03-6-1 clarifies that unvested share-based payment awards constitute participating securities, if such awards include nonforfeitable rights to dividends or dividend equivalents. Consequently, awards that are deemed to be participating securities must be allocated earnings in the computation of earnings per share under the two-class method. FSP EITF 03-6-1 is effective for us on January 1, 2009. We do not believe that FSP EITF 03-6-1 will have a material impact on our earnings per unit computations and disclosures.

In February 2008, FSP SFAS No, 157-2, *Effective Date of FASB Statement No. 157*, was issued. FSP 157-2 defers the effective date of SFAS 157, *Fair Value Measurements*, to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As allowed under FSP 157-2, we have not applied the provisions of SFAS 157 to our nonfinancial assets and liabilities measured at fair value, which include certain assets and liabilities acquired in business combinations. On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. See Note 5 for these fair value disclosures. We do not expect any immediate impact from adoption of the remaining portions of SFAS 157 on January 1, 2009.

In light of current market conditions, the FASB has issued additional clarifying guidance regarding the implementation of SFAS 157, particularly with respect to financial assets that do not trade in active markets such as investments in joint ventures. This clarifying guidance did not result in a change in our accounting, reporting or impairment testing for such investments. We continue to monitor developments at the FASB and SEC for new matters and guidance that may affect our valuation processes.

In April 2008, the FASB issued FSP No. 142-3, *Determination of the Useful Life of Intangible Assets* ("FSP 142-3"), which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful lives of recognized intangible assets under SFAS No. 142, *Goodwill and Other Intangible Assets*. This change is intended to improve consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of such assets under SFAS 141(R) and other accounting guidance. The requirement for determining useful lives must be applied prospectively to intangible assets acquired after January 1, 2009 and the disclosure requirements must be applied prospectively to all intangible assets recognized as of, and subsequent to, January 1, 2009. We will adopt the provisions of FSP 142-3 on January 1, 2009.

Revenue Recognition

Our Downstream Segment revenues are earned from pipeline transportation, marketing and storage of refined products and LPGs, intrastate pipeline transportation of petrochemicals, sale of product inventory and other ancillary services. Transportation revenues are recognized as products are delivered to customers. Storage revenues are recognized upon receipt of products into storage and upon performance of storage services. Refined products terminaling revenues are recognized as products are out-loaded. From time to time, we buy and sell products to balance our inventory for operational needs, and the revenues from the sale of product inventory are recognized when the products are sold. Our refined products marketing activities generate revenues by purchasing refined products from our throughput partner and establishing a margin by selling refined products for physical delivery through spot and contract sales. These marketing activities are conducted at our Aberdeen and Boligee truck racks to independent wholesalers and retailers of refined products. Spot purchases and sales are generally contracted to occur on the same day.

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

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

Our Midstream Segment revenues are earned from the gathering of natural gas, pipeline transportation of NGLs and fractionation of NGLs. Gathering revenues are recognized as natural gas is received from the customer. Transportation revenues are recognized as NGLs are delivered. Through March 31, 2008, fractionation revenues were recognized ratably over the contract year as products were delivered. Beginning April 1, 2008, based upon contract terms, fractionation revenues are recognized based upon the volume of NGLs fractionated at a fixed rate per gallon. We generally do not take title to the natural gas gathered, NGLs transported or NGLs fractionated, with the exception of inventory imbalances. Therefore, the results of our Midstream Segment are not directly affected by changes in the prices of natural gas or NGLs.

Our Marine Services Segment revenues are earned from inland and offshore transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges. We also provide offshore well-testing and other offshore services. Our transportation services are generally provided under term contracts (also referred to as affreightment contracts), which are agreements with specific customers to transport cargo from within designated operating areas at set day rates or a set fee per cargo movement. Most of the inland term contracts have one-year terms with the remainder having terms of up to two years. Substantially all of the inland contracts have renewal options, which are exercisable subject to agreement on rates applicable to the option terms. Most of the offshore service and transportation contracts have up to one-year terms with renewal options, which are exercisable subject to agreement on rates applicable to the option terms, or are spot contracts. A spot contract is an agreement with a customer to move cargo within designated operating areas for a rate negotiated at the time the cargo movement takes place. We do not assume ownership of the products we transport in this segment. As is typical for inland and offshore affreightment contracts, the term contracts establish set day rates but do not include revenue or volume guarantees. Most of the contracts include escalation provisions to recover specific increased operating costs such as incremental increases in labor. The costs of fuel and other specified operational fees and costs are directly reimbursed by the customer under most of the contracts.

NOTE 3. ACCOUNTING FOR UNIT-BASED AWARDS

The following table summarizes compensation expense by plan for the three months and nine months ended September 30, 2008 and 2007:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Phantom Unit Plans: (1) (2)				
1999 Phantom Unit Retention Plan	$ (91)	$ (51)	$ (40)	$ 731
2000 Long Term Incentive Plan	39	(25)	(135)	277
2005 Phantom Unit Plan	(32)	(112)	74	429
EPCO, Inc. 2006 TPP Long-Term Incentive Plan:				
Unit options	48	27	111	39
Restricted units (3)	284	135	671	199
Unit appreciation rights (“UARs”) (1) (2)	(1)	20	3	44
Phantom units (1)	--	3	8	7
TEPPCO Unit L.P.	30	--	30	--
Compensation expense allocated under ASA (4)	490	357	1,201	710
Total compensation expense	$ 767	$ 354	$ 1,923	$ 2,436

(1) These awards are accounted for as liability awards under the provisions of SFAS No. 123(R), *Share-Based Payment* (“SFAS 123(R)”). Accruals for plan award payouts are based on the Unit price.

(2) The decrease in compensation expense for the three months ended September 30, 2007 and the three months and nine months ended September 30, 2008, is primarily due to a decrease in the Unit price at September 30, 2007 and September 30, 2008, respectively, as compared to the Unit price at June 30, 2007, June 30, 2008 and December 31, 2007, respectively.

(3) As used in the context of the EPCO, Inc. 2006 TPP Long-Term Incentive Plan, the term “restricted unit” represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires.

(4) Represents compensation expense under equity awards under other EPCO compensation plans allocated to us from EPCO under the ASA in connection with shared service employees working on our behalf.

1999 Plan

The Texas Eastern Products Pipeline Company, LLC 1999 Phantom Unit Retention Plan (“1999 Plan”) provides for the issuance of phantom unit awards as incentives to key employees. In April 2008, 13,000 phantom units vested resulting in a cash payment of $0.4 million. A total of 18,600 phantom units were outstanding under the 1999 Plan at September 30, 2008. These awards cliff vest as follows: 13,000 in April 2009 and 5,600 in January 2010. At September 30, 2008 and December 31, 2007, we had accrued liability balances of $0.5 million and $1.0 million, respectively, for compensation related to the 1999 Plan.

2000 LTIP

The Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan (“2000 LTIP”) provides key employees incentives to achieve improvements in our financial performance. On December 31, 2007, 8,400 phantom units vested and $0.5 million was paid out to participants in the first quarter of 2008. At September 30, 2008, a total of 11,300 phantom units were outstanding under the 2000 LTIP that cliff vest on December 31, 2008 and will be paid out to participants in 2009. At September 30, 2008 and December 31, 2007, we had accrued liability balances of $0.3 million and $0.9 million, respectively, related to the 2000 LTIP.

2005 Phantom Unit Plan

The Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan ("2005 Phantom Unit Plan") provides key employees incentives to achieve improvements in our financial performance. On December 31, 2007, 36,200 phantom units vested and $1.6 million was paid out to participants in the first quarter of 2008. At September 30, 2008, a total of 36,600 phantom units were outstanding under the 2005 Phantom Unit Plan that cliff vest on December 31, 2008 and will be paid out to participants in 2009. At September 30, 2008 and December 31, 2007, we had accrued liability balances of $0.8 million and $2.6 million, respectively, for compensation related to the 2005 Phantom Unit Plan.

2006 LTIP

The EPCO, Inc. 2006 TPP Long-Term Incentive Plan ("2006 LTIP") provides for awards of our Units and other rights to our non-employee directors and to certain employees of EPCO and its affiliates providing services to us. Awards granted under the 2006 LTIP may be in the form of restricted units, phantom units, unit options, UARs and distribution equivalent rights. Subject to adjustment as provided in the 2006 LTIP, awards with respect to up to an aggregate of 5,000,000 Units may be granted under the 2006 LTIP. We reimburse EPCO for the costs allocable to 2006 LTIP awards made to employees who work in our business. The 2006 LTIP is effective until December 8, 2016 or, if earlier, the time which all available Units under the 2006 LTIP have been delivered to participants or the time of termination of the 2006 LTIP by EPCO or the Audit, Conflicts and Governance Committee of the Board of Directors of our General Partner ("ACG Committee"). In May 2008, we granted 200,000 unit options and 95,900 restricted units to certain employees providing services directly to us and 29,429 UARs to a non-executive member of the board of directors in connection with his election to the board. After giving effect to outstanding unit options and restricted units at September 30, 2008, and the forfeiture of restricted units through September 30, 2008, a total of 4,487,700 additional Units could be issued under the 2006 LTIP in the future.

Unit Options

The information in the following table presents unit option activity under the 2006 LTIP for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/Unit)	Weighted-Average Remaining Contractual Term (in years)
Unit Options:			
Outstanding at December 31, 2007 (1)	155,000	$ 45.35	--
Granted during 2008 (2)	200,000	35.86	--
Outstanding at September 30, 2008	355,000	$ 40.00	4.82
Options exercisable at:			
September 30, 2008	--	$ --	--

(1) During 2008, previous unit option grants were amended. The expiration dates of the 2007 awards were modified from May 22, 2017 to December 31, 2012.
(2) The total grant date fair value of these awards was $0.3 million based on the following assumptions: (i) expected life of the option of 4.7 years; (ii) risk-free interest rate of 3.3%; (iii) expected distribution yield on Units of 7.9%; (iv) estimated forfeiture rate of 17%; and (v) expected Unit price volatility on Units of 18.7%.

At September 30, 2008, total unrecognized compensation cost related to nonvested unit options granted under the 2006 LTIP was an estimated $0.6 million. We expect to recognize this cost over a weighted-average period of 3.2 years.

Restricted Units

The following table summarizes information regarding our restricted units for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted Units at December 31, 2007	62,400	
Granted during 2008 (2)	95,900	$ 32.97
Forfeited during 2008	(1,000)	35.86
Restricted Units at September 30, 2008	157,300	

(1) Determined by dividing the aggregate grant date fair value of awards (including an allowance for forfeitures) by the number of awards issued.
(2) Aggregate grant date fair value of restricted unit awards issued during the nine months ended September 30, 2008 was $2.8 million based on grant date market prices of our Units ranging from $34.63 to $35.86 per Unit and an estimated forfeiture rate of 17%.

None of our restricted units vested during the nine months ended September 30, 2008. At September 30, 2008, total unrecognized compensation cost related to restricted units was $4.1 million, and these costs are expected to be recognized over a weighted-average period of 3.05 years.

Phantom Units

At September 30, 2008, a total of 1,647 phantom units were outstanding, which have been awarded under the 2006 LTIP to non-executive members of the board of directors. Each phantom unit will pay out in cash on April 30, 2011 or, if earlier, the date the director is no longer serving on the board of directors, whether by voluntarily resignation or otherwise. Each participant is also entitled to cash distributions equal to the product of the number of phantom units granted to the participant and the per Unit cash distribution that we paid to our unitholders. Phantom unit awards to non-executive directors are accounted for similar to SFAS 123(R) liability awards.

UARs

At September 30, 2008, a total of 431,377 UARs were outstanding, which have been awarded under the 2006 LTIP to non-executive members of the board of directors and to certain employees providing services directly to us.

Non-Executive Members of the Board of Directors. On June 20, 2008, 29,429 UARs were awarded under the 2006 LTIP at an exercise price of $33.98 per Unit to a non-executive member of the board of directors in connection with his election to the board. At September 30, 2008, a total of 95,654 UARs, awarded to non-executive members of the board of directors under the 2006 LTIP, were outstanding at a weighted average exercise price of $41.82 per Unit. The UARs will be subject to five year cliff vesting and will vest earlier if the director dies or is removed from, or not re-elected or appointed to, the board of directors for reasons other than his voluntary resignation or unwillingness to serve. When the UARs become payable, the director will receive a payment in cash equal to the fair market value of the Units subject to the UARs on the payment date over the fair market value of the Units subject to the UARs on the date of grant. UARs awarded to non-executive directors are accounted for similar to SFAS 123(R) liability awards.

Employees. At September 30, 2008, a total of 335,723 UARs, awarded under the 2006 LTIP to certain employees providing services directly to us, were outstanding at an exercise price of $45.35 per Unit. The UARs are subject to five year cliff vesting and are subject to forfeiture. When the UARs become payable, the awards will be redeemed in cash (or, in the sole discretion of the ACG Committee, Units or a combination of cash and Units) equal to the fair market value of the Units subject to the UARs on the payment date over the fair market value of the Units subject to the UARs on the date of grant. In addition, for each calendar quarter from the grant date until the UARs become payable, each holder will receive a cash payment equal to the product of (i) the per Unit cash distribution paid to our unitholders during such calendar quarter less the quarterly distribution amount in effect at the time of grant multiplied by (ii) the number of Units subject to the UAR. UARs awarded to employees are accounted for as liability awards under SFAS 123(R) since the current intent is to settle the awards in cash.

Employee Partnership

On September 4, 2008, EPCO formed a Delaware limited partnership, TEPPCO Unit L.P. ("TEPPCO Unit"), for which it serves as the general partner, to serve as an incentive arrangement for certain employees of EPCO providing services to us. EPCO Holdings, Inc. ("EPCO Holdings"), an affiliate of EPCO, contributed approximately $7.0 million to TEPPCO Unit as a capital contribution with respect to its interest and was admitted as the Class A limited partner of TEPPCO Unit. TEPPCO Unit purchased 241,380 Units directly from us in an unregistered transaction at the public offering price concurrently with the closing of our September 2008 equity offering (see Note 12). Certain EPCO employees who perform services for us, including the executive officers named in the Executive Compensation section of our most recent Annual Report on Form 10-K, were issued Class B limited partner interests and admitted as Class B limited partners of TEPPCO Unit without any capital contribution. The Class B limited partner interests, which entitle the holder to participate in the appreciation in value of our Units, are equity-based compensatory awards designed to incentivize officers and employees of EPCO who perform services for us to enhance the long-term value of our Units.

The Class B limited partner interests in TEPPCO Unit that are owned by EPCO employees are subject to forfeiture if the participating employee's employment with EPCO and its affiliates is terminated prior to September 4, 2013, with the customary exceptions for death, disability or certain retirements. The risk of forfeiture associated with the Class B limited partner interests in TEPPCO Unit will also lapse upon certain change of control events.

Unless otherwise agreed to by EPCO, and a majority in interest of the Class B limited partners of TEPPCO Unit, TEPPCO Unit will terminate at the earlier of September 4, 2013 (five years from the date of TEPPCO Unit's agreement of limited partnership) or a change in control of us, our General Partner or EPCO. Summarized below are certain material terms regarding quarterly cash distributions by TEPPCO Unit to its partners:

- § Distributions of cash flow – Each quarter, 100% of the cash distributions received by TEPPCO Unit from us in that quarter will be distributed to the Class A limited partner until the Class A limited partner has received an amount equal to the Class A preferred return (as defined below), and any excess distributions received by TEPPCO Unit in that quarter will be distributed to the Class B limited partners. The Class A preferred return equals the Class A capital base (as defined below) multiplied by a floating rate determined by EPCO, in its sole discretion, that will be no less than 4.5% and no greater than 5.725% per annum. The Class A limited partner's capital base equals the amount of any other contributions of cash or cash equivalents made by the Class A limited partner to TEPPCO Unit, plus any unpaid Class A preferred return from prior periods, less any distributions made by TEPPCO Unit of proceeds from the sale of Units owned by TEPPCO Unit (as described below).

- § Liquidating Distributions – Upon liquidation of TEPPCO Unit, Units having a fair market value equal to the Class A limited partner capital base will be distributed to EPCO Holdings, plus any accrued

Class A preferred return for the quarter in which liquidation occurs. Any remaining Units will be distributed to the Class B limited partners.

§ Sale Proceeds – If TEPPCO Unit sells any Units that it beneficially owns, the sale proceeds will be distributed to the Class A limited partner and the Class B limited partners in the same manner as liquidating distributions described above.

Compensation expense attributable to these awards was based on the estimated grant date fair value of each award. A portion of the fair value of these equity awards are allocated to us under the ASA as a non-cash expense. We will not reimburse EPCO, TEPPCO Unit or any of their affiliates or partners, through the ASA or otherwise, for any expenses related to TEPPCO Unit, including the $7.0 million contribution to TEPPCO Unit or the purchase of the unregistered Units by TEPPCO Unit. The grant date fair value of the Class B limited partnership interests in TEPPCO Unit was $2.1 million. This fair value was estimated using the Black-Scholes option pricing model, which incorporates various assumptions including (i) an expected life of the awards of five years, (ii) risk-free interest rate of 2.87%, (iii) an expected distribution yield on our Units of 7.28%, and (iv) an expected Unit price volatility for our Units of 16.42%. At September 30, 2008, there was an estimated $1.7 million of unrecognized compensation cost related to TEPPCO Unit. We will recognize our share of these costs in accordance with the ASA over a weighted average period of 4.93 years.

NOTE 4. EMPLOYEE BENEFIT PLANS

Retirement Plan

The TEPPCO Retirement Cash Balance Plan ("TEPPCO RCBP") was a non-contributory, trustee-administered pension plan. 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 this plan.

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 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 had 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 Internal Revenue Service ("IRS") providing IRS approval of the plan termination. For those plan participants who elected to receive an annuity, we purchased an annuity contract from an insurance company in which the plan participants own the annuity, absolving us of any future obligation to the participants.

As of December 31, 2007, all benefit obligations to plan participants have been settled. During the first quarter of 2008, the remaining balance of the TEPPCO RCBP was transferred to an EPCO benefit plan.

EPCO maintains defined contribution plans for the benefit of employees providing services to us, and we reimburse EPCO for the cost of maintaining these plans in accordance with the ASA (see Note 14 for additional information related to the costs and expenses allocated to us for employee benefits).

NOTE 5. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices and interest rates. We do not have foreign exchange risks. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to fair values of certain debt instruments and cash flows resulting from changes in applicable interest rates or commodity prices.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed interest rate borrowings under various debt agreements. From time to time we utilize interest rate swaps and similar arrangements to manage a portion of our interest rate exposure, which allows us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt.

Fair Value Hedges – Interest Rate Swaps

In January 2006, we entered into interest rate swap agreements with a total notional value of $200.0 million to hedge our exposure to increases in the benchmark interest rate underlying our variable rate revolving credit facility. Under the swap agreements, we paid a fixed rate of interest ranging from 4.67% to 4.695% and received a floating rate based on the three-month U.S. Dollar LIBOR rate. At December 31, 2007, the fair value of these interest rate swaps was an asset of $0.3 million. These interest rate swaps expired in January 2008.

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. This swap agreement, designated as a fair value hedge, had a notional value of $210.0 million and was set to mature in January 2028 to match the principal and maturity of the TE Products Senior Notes. During the three months and nine months ended September 30, 2007, we recognized reductions in interest expense of $0.1 million and $0.7 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. In September 2007, we terminated this swap agreement, resulting in a loss of $1.2 million. This loss was deferred as an adjustment to the carrying value of the 7.51% Senior Notes, and approximately $0.2 million of the loss was amortized to interest expense in 2007, with the remaining $1.0 million recognized in interest expense in January 2008 at the time the 7.51% Senior Notes were redeemed (see Note 11).

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 value of $500.0 million and were set to mature in 2012 to match the principal and maturity of the underlying debt. These swap agreements were terminated in 2002 resulting in deferred gains of $44.9 million, which are being amortized using the effective interest method as reductions to future interest expense over the remaining term of the 7.625% Senior Notes. At September 30, 2008 and December 31, 2007, the unamortized balance of the deferred gains was $19.4 million and $23.2 million, respectively. In the event of early extinguishment of the 7.625% Senior Notes, any remaining unamortized gains would be recognized in the statement of consolidated income at the time of extinguishment.

Cash Flow Hedges – Treasury Locks

At times, we may use treasury lock financial instruments to hedge the underlying U.S. treasury rates related to anticipated debt incurrence. Gains or losses on the termination of such instruments are amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. Each of our treasury lock transactions was designated as a cash flow hedge under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted.

In October 2006 and February 2007, we entered into treasury lock agreements, accounted for as cash flow hedges, which extended through June 2007 for a notional value totaling $300.0 million. In May 2007, these treasury locks were terminated concurrent with the issuance of junior subordinated notes (see Note 11). The termination of the treasury locks resulted in gains of $1.4 million, and these gains were recorded in accumulated other comprehensive income. These gains are being amortized using the effective interest method as reductions to future interest expense over the term of the forecasted fixed rate interest payments, which is ten years. Over the next twelve months, we expect to reclassify $0.1 million of accumulated other comprehensive income that was generated by these treasury locks as a reduction to interest expense. In the event of early extinguishment of the junior subordinated notes, any remaining unamortized gains would be recognized in the statement of consolidated income at the time of extinguishment.

In 2007, we entered into treasury locks, accounted for as cash flow hedges, which extended through January 31, 2008 for a notional value totaling $600.0 million. At December 31, 2007, the fair value of the treasury locks was a liability of $25.3 million. In January 2008, these treasury locks were extended through April 30, 2008. In March 2008, these treasury locks were settled concurrently with the issuance of senior notes (see Note 11). The settlement of the treasury locks resulted in losses of $52.1 million, and these losses were recorded in accumulated other comprehensive income. We recognized approximately $3.6 million of this loss in interest expense as a result of interest payments hedged under the treasury locks not occurring as forecasted. The remaining losses are being amortized using the effective interest method as increases to future interest expense over the terms of the forecasted interest payments, which range from five to ten years. Over the next twelve months, we expect to reclassify $5.7 million of accumulated other comprehensive loss that was generated by these treasury locks as an increase to interest expense. In the event of early extinguishment of these senior notes, any remaining unamortized losses would be recognized in the statement of consolidated income at the time of extinguishment.

Commodity Risk Hedging Program

We seek to maintain a position that is substantially balanced between crude oil purchases and related sales and future delivery obligations. As part of our crude oil marketing business, we enter into financial instruments such as swaps and other hedging instruments. The purpose of such hedging activity is to either balance our inventory position or to lock in a profit margin.

At September 30, 2008 and December 31, 2007, we had a limited number of commodity financial instruments that were accounted for as cash flow hedges. The majority of these contracts will expire during 2008, with the remainder expiring during 2009, and any amounts remaining in accumulated other comprehensive income will be recorded in net income upon the contract expiration. Gains and losses on these financial instruments 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. No ineffectiveness was recognized as of September 30, 2008. In addition, we had some commodity financial instruments that did not qualify for hedge accounting. These financial instruments had a minimal impact on our earnings. The fair values of the open positions at September 30, 2008 and December 31, 2007 were liabilities of $2.8 million and $18.9 million, respectively.

Adoption of SFAS 157 – Fair Value Measurements

On January 1, 2008, we adopted the provisions of SFAS No. 157, *Fair Value Measurements*, that apply to financial assets and liabilities. We will adopt the provisions of SFAS 157 that apply to nonfinancial assets and liabilities on January 1, 2009. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Our fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability. These assumptions include estimates of risk. Recognized valuation techniques employ inputs such as product prices, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data, or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the extent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

SFAS 157 established a three-tier hierarchy that classifies fair value amounts recognized or disclosed in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy. The characteristics of fair value amounts classified within each level of the SFAS 157 hierarchy are described as follows:

§ Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur in sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the NYSE or New York Mercantile Exchange). Level 1 primarily consists of financial assets and liabilities such as exchange-traded financial instruments, publicly-traded equity securities and U.S. government treasury securities.

§ Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value of money, volatility factors for stocks, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are validated by inputs other than quoted prices (e.g., interest rates and yield curves at commonly quoted intervals). Level 2 includes non-exchange-traded instruments such as over-the-counter forward contracts, options, and repurchase agreements.

§ Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally-developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Level 3 generally includes specialized or unique financial instruments that are tailored to meet a customer's specific needs.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities measured on a recurring basis at September 30, 2008. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels. At September 30, 2008, we had no Level 1 financial assets and liabilities.

	Level 2	Level 3	Total
Financial assets:			
Commodity financial instruments	$ 24,339	$ 1,597	$ 25,936
Total	$ 24,339	$ 1,597	$ 25,936
Financial liabilities:			
Commodity financial instruments	$ 28,694	$ 58	$ 28,752
Total	$ 28,694	$ 58	$ 28,752
Net financial assets, Level 3		$ 1,539	

The determination of fair values above associated with our commodity financial instrument portfolios are developed using available market information and appropriate valuation techniques in accordance with SFAS 157.

The following table sets forth a reconciliation of changes in the fair value of our net financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Net Commodity Financial Instruments
Balance, January 1, 2008	$ (394)
Total gains included in net income (1)	418
Balance, March 31, 2008	$ 24
Total losses included in net income (1)	(66)
Balance, June 30, 2008	$ (42)
Total gains included in net income (1)	1,581
Ending balance, September 30, 2008	$ 1,539

(1) Total commodity financial instrument gains, recognized in revenues and included in net income on our statements of consolidated income, were $1.6 million and $1.9 million for the three months and nine months ended September 30, 2008, respectively.

NOTE 6. INVENTORIES

Inventories are valued at the lower of cost (based on weighted average cost method) or market. The major components of inventories were as follows:

	September 30, 2008	December 31, 2007
Crude oil (1)	$ 135,684	$ 44,542
Refined products and LPGs (2)	13,209	18,616
Lubrication oils and specialty chemicals	11,631	9,160
Materials and supplies	8,104	7,178
NGLs	1,662	803
Total	$ 170,290	$ 80,299

(1) At September 30, 2008 and December 31, 2007, $117.7 million and $16.5 million, respectively, of our crude oil inventory was subject to forward sales contracts.
(2) Refined products and LPGs inventory is managed on a combined basis.

Due to fluctuating commodity prices, we recognize lower of cost or market ("LCM") adjustments when the carrying value of our inventories exceed their net realizable value. These non-cash charges are a component of costs and expenses in the period they are recognized. For the three months ended September 30, 2008 and for the nine months ended September 30, 2008 and 2007, we recognized LCM adjustments of approximately $9.3 million, $9.4 million and $0.6 million, respectively. For the three months ended September 30, 2007, we had no LCM adjustments.

NOTE 7. PROPERTY, PLANT AND EQUIPMENT

Major categories of property, plant and equipment at September 30, 2008 and December 31, 2007, were as follows:

	Estimated Useful Life In Years	September 30, 2008	December 31, 2007
Plants and pipelines (1)	5-40(4)	$ 1,872,107	$ 1,810,195
Underground and other storage facilities (2)	5-40(5)	286,212	254,677
Transportation equipment (3)	5-10	10,245	7,780
Marine vessels	20-30	445,341	--
Land and right of way		141,547	117,628
Construction work in progress		269,178	185,579
Total property, plant and equipment		$ 3,024,630	$ 2,375,859
Less accumulated depreciation		651,936	582,225
Property, plant and equipment, net		$ 2,372,694	$ 1,793,634

(1) Plants and pipelines include refined products, LPGs, NGL, petrochemical, crude oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings, laboratory and shop equipment; and related assets.
(2) Underground and other storage facilities include underground product storage caverns; storage tanks; and other related assets.
(3) Transportation equipment includes vehicles and similar assets used in our operations.

(4) The estimated useful lives of major components of this category are as follows: pipelines, 20-40 years (with some equipment at 5 years); terminal facilities, 10-40 years; office furniture and equipment, 5-10 years; buildings 20-40 years; and laboratory and shop equipment, 5-40 years.
(5) The estimated useful lives of major components of this category are as follows: underground storage facilities, 20-40 years (with some components at 5 years) and storage tanks, 20-30 years.

The following table summarizes our depreciation expense and capitalized interest amounts for the three months and nine months ended September 30, 2008 and 2007:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Depreciation expense (1)	$ 24,414	$ 20,542	$ 70,261	$ 59,914
Capitalized interest (2)	4,292	2,010	14,177	8,813

(1) Depreciation expense is a component of depreciation and amortization expense as presented in our statements of consolidated income.
(2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.

Asset Retirement Obligations

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of a tangible long-lived asset that results from its acquisition, construction, development or normal operation or a combination of these factors. We have conditional AROs related to the retirement of the Val Verde Gas Gathering Company, L.P. ("Val Verde") natural gas gathering system and to structural restoration work to be completed on leased office space that is required upon our anticipated office lease termination. At September 30, 2008, we have a $1.4 million liability, which represents the fair values of these conditional AROs. We assigned probabilities for settlement dates and settlement methods for use in an expected present value measurement of fair value and recorded conditional AROs.

The following table presents information regarding our AROs:

ARO liability balance, December 31, 2007	$ 1,346
Liabilities incurred	--
Liabilities settled	--
Accretion expense	95
ARO liability balance, September 30, 2008	$ 1,441

Property, plant and equipment at September 30, 2008, includes $0.5 million of asset retirement costs capitalized as an increase in the associated long-lived asset.

NOTE 8. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

We own interests in related businesses that are accounted for using the equity method of accounting. These investments are identified below by reporting business segment (see Note 13 for a general discussion of our business segments). The following table presents our investments in unconsolidated affiliates as of September 30, 2008 and December 31, 2007:

	Ownership Percentage at September 30, 2008	September 30, 2008	December 31, 2007
Downstream Segment:			
Centennial	50.0%	$ 73,616	$ 78,962
Other	25.0%	369	362
Upstream Segment:			
Seaway	50.0%	193,819	188,650
Texas Offshore Port System	33.3%	2,354	--
Midstream Segment:			
Jonah	80.64%	921,219	879,021
Total		$ 1,191,377	$ 1,146,995

The following table summarizes equity earnings by business segment for the three months and nine months ended September 30, 2008 and 2007:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Equity earnings (losses):				
Downstream Segment	$ (2,349)	$ (3,064)	$ (10,066)	$ (8,430)
Upstream Segment	2,748	1,073	9,925	4,310
Midstream Segment	21,863	21,056	67,444	62,430
Intersegment eliminations	(129)	(6)	(4,091)	(3,454)
Total equity earnings	$ 22,133	$ 19,059	$ 63,212	$ 54,856

On a quarterly basis, we monitor the underlying business fundamentals of our investments in unconsolidated affiliates and test such investments for impairment when impairment indicators are present. As a result of our reviews for the third quarter 2008, no impairment charges were required. We have the intent and ability to hold these investments, which are integral to our operations.

Seaway

Through one of our indirect wholly owned subsidiaries, we own a 50% ownership interest in Seaway. The remaining 50% interest is owned by ConocoPhillips. We operate and commercially manage the Seaway assets. Seaway owns pipelines and terminals that carry imported, offshore and domestic onshore 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. Seaway also has a connection to our South Texas system that allows it to receive both onshore and offshore domestic crude oil in the Texas Gulf Coast area for delivery to Cushing. The Seaway Crude Pipeline Company Partnership Agreement provides for varying participation ratios throughout the life of Seaway. Our sharing ratio (including the amount of distributions we receive) of Seaway for each of the nine months ended September 30, 2008 and 2007 was 40% of revenue and expense (and distributions) and will remain at that level in the future. During the nine months ended September 30, 2008 and 2007, we received distributions from Seaway of $7.4 million and $9.2 million, respectively. During the nine months ended September 30, 2008 and 2007, we did not invest any funds in Seaway.

Texas Offshore Port System

In August 2008, we, together with Enterprise Products Partners and Oiltanking Holding Americas, Inc. (“Oiltanking”) announced the formation of a joint venture to design, construct, operate and own a new Texas offshore crude oil port and pipeline system to facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. The joint venture’s primary project, referred to as “TOPS,” includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of total crude oil storage capacity, and (iii) an 85-mile pipeline system that will have the capacity to deliver up to 1.8 million barrels per day of crude oil, that will extend from the offshore port to a Texas City, Texas storage facility. TOPS is expected to begin service as early as the fourth quarter of 2010. The joint venture’s second and complementary project, referred to as the Port Arthur Crude Oil Express (“PACE”) will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. PACE is expected to begin service as early as the third quarter of 2010. Development of the TOPS and PACE projects is supported by long-term contracts with affiliates of Motiva Enterprises, LLC and Exxon Mobil Corporation, which have committed a combined 725,000 barrels per day of crude oil to the projects.

We, Enterprise Products Partners and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. A subsidiary of Enterprise Products Partners acts as construction manager and will act as operator. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures occurring in 2009 and 2010. We and an affiliate of Enterprise Products Partners have each guaranteed up to approximately $700.0 million of the capital contribution obligations of our respective subsidiary partners in the joint venture. At September 30, 2008, we have a payable of $2.3 million for our investment in the joint venture, which will be paid during the fourth quarter of 2008.

Centennial

TE Products owns a 50% ownership interest in 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. Marathon operates the mainline Centennial pipeline, and TE Products operates the Beaumont origination point and the Creal Springs terminal. During the nine months ended September 30, 2008, we did not invest any funds in Centennial. During the nine months ended September 30, 2007, we contributed $11.1 million to Centennial, of which $6.1 million was for contractual obligations that were created upon formation of Centennial and $5.0 million was for debt service requirements. TE Products has received no cash distributions from Centennial since its formation.

Jonah

Enterprise Products Partners, through its affiliate, Enterprise Gas Processing, LLC, is our joint venture partner in Jonah, the partnership through which we have owned our interest in the system serving the Jonah and Pinedale fields in the greater Green River Basin in southwestern Wyoming. The joint venture is governed by a management committee comprised of two representatives approved by Enterprise Products Partners and two representatives approved by us, each with equal voting power. Enterprise Products Partners serves as operator. In June 2008, Jonah completed the Phase V expansion, which increased the combined system capacity of the Jonah and Pinedale fields from 1.5 billion cubic feet (“Bcf”) per day to 2.35 Bcf per day. The expansion is expected to significantly reduce system operating pressures, which is anticipated to lead to increased production rates and ultimate reserve recoveries. Enterprise Products Partners managed the Phase V construction project.

From August 1, 2006 through July 2007, we and Enterprise Products Partners equally shared the costs of the Phase V expansion, and Enterprise Products Partners shared in the incremental cash flow resulting from the operation of those new facilities. During August 2007, with the completion of the first portion of the expansion, we and Enterprise Products Partners began sharing joint venture cash distributions and earnings based on a formula that takes into account the capital contributions of the parties, including expenditures by us prior to the expansion. Based on this formula in the partnership agreement, beginning in August 2007, our ownership interest in Jonah was approximately 80.64%, and Enterprise Products Partners' ownership interest in Jonah was approximately 19.36%. Amounts exceeding an agreed upon base cost estimate of $415.2 million were shared 19.36% by Enterprise Products Partners and 80.64% by us. Our ownership interest in Jonah is currently anticipated to remain at 80.64%. Through September 30, 2008, we have reimbursed Enterprise Products Partners $303.9 million ($42.3 million in 2008, $152.2 million in 2007 and $109.4 million in 2006) for our share of the Phase V cost incurred by it (including its cost of capital incurred prior to the formation of the joint venture of $1.3 million). At September 30, 2008 and December 31, 2007, we had payables to Enterprise Products Partners for costs incurred of $1.3 million and $9.9 million, respectively.

In early 2008, Jonah began an expansion of the portion of its system serving the Pinedale field, which is expected to increase the combined system capacity of the Jonah and Pinedale fields from 2.35 Bcf per day to approximately 2.55 Bcf per day. This project will include an additional 17,000 horsepower of compression at the Paradise and Bird Canyon stations in Sublette County, Wyoming and involve construction of approximately 52 miles of 30-inch and 24-inch diameter pipelines. This expansion is expected to be completed in phases, with final completion expected in early 2009. The total anticipated cost of this system expansion is expected to be approximately $125.0 million. Our share of the costs of the construction is expected to be 80.64%, and Enterprise Products Partners' share is expected to be 19.36%. Enterprise Products Partners is managing this construction project.

During the nine months ended September 30, 2008 and 2007, we received distributions from Jonah of $111.6 million and $77.3 million, respectively. The 2007 amount included $11.6 million of distributions declared in 2006 and paid during the first quarter of 2007. During the nine months ended September 30, 2008 and 2007, we invested $94.9 million and $127.8 million, respectively, in Jonah.

Summarized Financial Information of Unconsolidated Affiliates

Summarized combined income statement data by reporting segment for the three months and nine months ended September 30, 2008 and 2007, is presented below (on a 100% basis):

	For the Three Months Ended					
	September 30, 2008			September 30, 2007		
	Revenues	Operating Income	Net Income (Loss)	Revenues	Operating Income	Net Income
Downstream Segment (1)	$ 9,439	$ 2,438	$ (212)	$ 15,728	$ 6,346	$ 3,682
Upstream Segment	24,603	11,615	11,680	16,802	6,231	6,303
Midstream Segment	58,662	27,007	27,152	47,359	23,223	23,455

	For the Nine Months Ended					
	September 30, 2008			September 30, 2007		
	Revenues	Operating Income	Net Income (Loss)	Revenues	Operating Income	Net Income
Downstream Segment (1)	$ 29,467	$ 4,595	$ (3,484)	$ 43,326	$ 9,786	$ 1,587
Upstream Segment	72,557	37,284	37,401	51,443	20,374	20,623
Midstream Segment	176,979	83,177	83,757	150,282	66,766	67,496

(1) On March 1, 2007, we sold our ownership interest in Mont Belvieu Storage Partners, L.P. ("MB Storage") to Louis Dreyfus Energy Services L.P. ("Louis Dreyfus") (see Note 9).

Summarized combined balance sheet information by reporting segment as of September 30, 2008 and December 31, 2007, is presented below:

	September 30, 2008					
	Current Assets	Noncurrent Assets	Current Liabilities	Long-term Debt	Noncurrent Liabilities	Equity
Downstream Segment	$ 16,394	$ 241,707	$ 21,806	$ 122,350	$ 1,748	$ 112,197
Upstream Segment	43,791	255,412	14,015	--	24	285,164
Midstream Segment	54,896	1,144,252	54,538	--	274	1,144,336

	December 31, 2007					
	Current Assets	Noncurrent Assets	Current Liabilities	Long-term Debt	Noncurrent Liabilities	Equity
Downstream Segment	$ 20,864	$ 248,896	$ 23,814	$ 129,900	$ 365	$ 115,681
Upstream Segment	16,429	251,635	6,457	--	38	261,569
Midstream Segment	55,396	1,065,304	22,545	--	264	1,097,891

NOTE 9. ACQUISITIONS AND DISPOSITIONS

Acquisitions

Cenac

On February 1, 2008, we, through our subsidiary, TEPPCO Marine Services, entered the marine transportation business for refined products, crude oil and condensate. We acquired transportation assets and certain intangible assets that comprised the marine transportation business of Cenac Towing Co., Inc. ("Cenac Towing"), Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr., the sole owner of Cenac Towing Co., Inc. and Cenac Offshore, L.L.C. (collectively, "Cenac"). The aggregate value of total consideration we paid or issued to complete the Cenac acquisition was $444.7 million, which consisted of $258.1 million in cash and 4,854,899 newly issued Units. Additionally, we assumed $63.2 million of Cenac's long-term debt in this transaction. On February 1, 2008, we repaid the $63.2 million of assumed debt in full with borrowings under our term credit agreement (see Note 11).

The following table summarizes the components of total consideration paid or issued in this transaction.

Cash payment for Cenac acquisition	$	256,593
Fair value of our 4,854,899 Units		186,558
Other cash acquisition costs paid to third-parties		1,530
Total consideration	$	444,681

We financed the cash portion of the consideration with borrowings under our term credit agreement (see Note 11). In accordance with purchase accounting, the value of our Units issued in connection with the Cenac acquisition was based on the average closing price of such Units immediately prior to and on the day of February 1, 2008. For the purpose of this calculation, the average closing price was $38.43 per Unit.

We acquired 42 tow boats, 89 tank barges and the economic benefit of certain related commercial agreements. This business serves refineries and storage terminals along the Mississippi, Illinois and Ohio rivers, and the Intracoastal Waterway between Texas and Florida. These assets also gather crude oil from production facilities and platforms along the U.S. Gulf Coast and in the Gulf of Mexico. This acquisition is a natural extension of our existing assets and complements two of our core franchise businesses: the transportation and storage of refined products and the gathering, transportation and storage of crude oil.

The results of operations for the Cenac acquisition are included in our consolidated financial statements beginning at the date of acquisition, in a newly created business segment, Marine Services Segment. Our fleet of acquired tow boats and tank barges will continue to be operated by employees of Cenac under a transitional operating agreement with TEPPCO Marine Services for a period of up to two years following the acquisition. These operations will remain headquartered in Houma, Louisiana during such time.

The purchase agreement gives us the right to repurchase the approximately 4.9 million Units issued in the transaction in connection with proposed sales thereof by Cenac and specified related persons for 10 years. If we or any of our affiliates sell any of the assets acquired from Cenac Towing prior to June 30, 2018 and recognize certain “built-in gains” for federal income tax purposes that are allocable to Cenac Towing, we have indemnification obligations under the purchase agreement to pay Cenac Towing an amount generally intended to compensate for the incremental level of double taxation imposed on Cenac Towing as a result of the sale. The purchase agreement prohibits Cenac from competing with our marine services business for two years or from soliciting employees and service providers of TEPPCO Marine Services and its affiliates for four years. The purchase agreement contains other customary representations, warranties, covenants and indemnification provisions.

This acquisition was accounted for using the purchase method of accounting and, accordingly, the cost has been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary fair values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis. We expect to finalize the purchase price allocation for this transaction during 2008.

The following table summarizes estimated fair values of the assets acquired and liabilities assumed at the date of acquisition.

Property, plant and equipment	$ 360,146
Intangible assets	63,500
Other assets	2,726
Total assets acquired	426,372
Long-term debt	(63,157)
Total liabilities assumed	(63,157)
Total assets acquired less liabilities assumed	363,215
Total consideration given	444,681
Goodwill	$ 81,466

The $63.5 million preliminary fair value of acquired intangible assets represents customer relationships and non-compete agreements. Customer relationship intangible assets represent the estimated economic value attributable to certain relationships acquired in connection with the Cenac acquisition whereby (i) we acquired information about or access to customers and now have regular contact with them and (ii) the customers now have the ability to make direct contact with us. In this context, customer relationships arise from contractual arrangements (such as transportation contracts) and through means other than contracts, such as regular contact by sales or service representative. The values assigned to these intangible assets are amortized to earnings on a straight-line basis over the expected period of economic benefit, which ranges from 2 to 20 years.

Of the $444.7 million in consideration we paid or issued to complete the Cenac acquisition, $81.5 million has been assigned to goodwill. Management attributes the value of this goodwill to potential future benefits we expect to realize as a result of acquiring these assets.

Since the closing date of the Cenac acquisition was February 1, 2008, our statements of consolidated income do not include any earnings from these assets prior to this date. The following table presents selected pro forma earnings information for the three months ended September 30, 2007 and for the nine months ended September 30, 2008 and 2007 as if the Cenac acquisition had been completed on January 1, 2008 and 2007, respectively, instead of February 1, 2008. This information was prepared based on financial data available to us and reflects certain estimates and assumptions made by our management. Our pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had the Cenac acquisition actually occurred on January 1, 2007 or 2008.

	For the Three Months Ended September 30,	For the Nine Months Ended September 30,	
	2007	2008	2007
Pro forma earnings data:			
Revenues	$ 2,607,501	$ 11,206,246	$ 6,683,552
Costs and expenses	2,549,614	11,000,934	6,488,639
Operating income	57,887	205,312	194,913
Net income	49,052	160,926	234,373
Basic and diluted earnings per unit:			
Units outstanding, as reported	89,868	95,145	89,835
Units outstanding, pro forma	94,723	100,000	94,690
Basic and diluted earnings per unit, as reported	$ 0.44	$ 1.39	$ 2.17
Basic and diluted earnings per unit, pro forma	$ 0.43	$ 1.34	$ 2.07

Horizon

On February 29, 2008, we expanded our Marine Services Segment with the acquisition of marine assets from Horizon Maritime, L.L.C. ("Horizon"), a privately-held Houston-based company and an affiliate of Mr. Cenac for $80.8 million in cash. We acquired 7 tow boats, 17 tank barges, rights to two tow boats under construction and certain related commercial and other agreements (or the associated economic benefits). In April 2008, we paid $3.0 million to Horizon pursuant to the purchase agreement upon delivery of one of the tow boats under construction, and in June 2008, we paid $3.8 million upon delivery of the second tow boat. The acquired vessels transport asphalt, heavy fuel oil and other heated oil products to storage facilities and refineries along the Mississippi, Illinois and Ohio Rivers, and the Intracoastal Waterway. We financed the acquisition with borrowings under our term credit agreement.

The results of operations for the Horizon acquisition are included in our consolidated financial statements beginning at the date of acquisition, in our Marine Services Segment. This acquisition was accounted for using the purchase method of accounting and, accordingly, the cost has been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary fair values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis. We expect to finalize the purchase price allocation for this transaction during 2008. The following table summarizes estimated fair values of the assets acquired and liabilities assumed at the date of acquisition.

Property, plant and equipment	$	71,216
Intangible assets		6,500
Other assets		981
Total assets acquired		78,697
Total consideration given		87,525
Goodwill	$	8,828

The $6.5 million preliminary fair value of acquired intangible assets represents customer relationships and non-compete agreements. Customer relationship intangible assets represent the estimated economic value attributable to certain relationships acquired in connection with the Horizon acquisition whereby (i) we acquired information about or access to customers and now have regular contact with them and (ii) the customers now have the ability to make direct contact with us. In this context, customer relationships arise from contractual arrangements (such as transportation contracts) and through means other than contracts, such as regular contact by sales or service representative. The values assigned to these intangible assets are amortized to earnings on a straight-line basis over the expected period of economic benefit, which ranges from 2 to 9 years.

Of the $87.5 million in consideration we paid to complete the acquisition of the Horizon business, $8.8 million has been assigned to goodwill. Management attributes the value of this goodwill to potential future benefits we expect to realize as a result of acquiring these assets and further expanding our Marine Services Segment.

Lubrication and Other Fuel Oil Assets

On August 1, 2008, we purchased lubrication and other fuel oil assets, located in Wyoming, from Quality Petroleum, Inc. for approximately $7.5 million. The assets, included in our Upstream Segment, consist of operating inventory, buildings, land and various equipment and the assignment of certain distributor agreements. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price primarily to property, plant and equipment, goodwill, inventory and intangible assets. We recorded $0.6 million of goodwill related to this acquisition.

Cavern Assets

On July 31, 2007, we purchased assets from Duke Energy Ohio, Inc. and Ohio River Valley Propane, LLC for approximately $6.0 million. The assets, included in our Downstream Segment, consist of an active 170,000 barrel LPG storage cavern, the associated piping and related equipment and a one bay truck rack. These assets are located adjacent to our Todhunter facility near Middleton, Ohio and are connected to our existing LPG pipeline. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price to property, plant and equipment.

Crude Oil Pipeline Assets

On September 27, 2007, we purchased assets from Shell Pipeline Company LP for approximately $6.8 million. The assets, included in our Upstream Segment, consist of approximately 44 miles of pipeline in South Texas and related equipment. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price to property, plant and equipment.

Dispositions

MB Storage and Other Related Assets

On March 1, 2007, TE Products sold its 49.5% ownership interest in MB Storage, its 50% ownership interest in Mont Belvieu Venture, LLC (the general partner of MB Storage) and other related assets to Louis Dreyfus for a total of approximately $156.1 million in cash, which includes approximately $18.5 million for other TE Products assets. This sale was in compliance with the October 2006 order and consent agreement with the Bureau of Competition of the Federal Trade Commission (“FTC”) and was completed in accordance with the terms and conditions approved by the FTC in February 2007. We used the proceeds from the transaction to partially fund our 2007 portion of the Jonah Phase V expansion and other organic growth projects. We recognized gains of approximately $59.6 million and $13.2 million related to the sale of our equity interests and other related assets of TE Products, respectively, which are included in gain on sale of ownership interest in MB Storage and gain on the sale of assets, respectively, in our statements of consolidated income.

In accordance with a transition services agreement between TE Products and Louis Dreyfus effective as of March 1, 2007, TE Products will provide certain administrative services to MB Storage for a period of up to two years after the sale, for a fee equal to 110% of the direct costs and expenses TE Products and its affiliates incur to provide the transition services to MB Storage. Payments for these services will be made according to the terms specified in the transition services agreement.

Other Refined Products Assets

On January 23, 2007, we sold a 10-mile, 18-inch segment of pipeline to an affiliate of Enterprise Products Partners for approximately $8.0 million in cash. These assets were part of our Downstream Segment and had a net book value of approximately $2.5 million. The sales proceeds were used to fund construction of a replacement pipeline in the area, in which the new pipeline provides greater operational capability and flexibility. We recognized a gain of approximately $5.5 million on this transaction, which is included in gain on sale of assets in our statements of consolidated income.

NOTE 10. INTANGIBLE ASSETS AND GOODWILL

Intangible Assets

The following table summarizes our intangible assets, including excess investments, being amortized at September 30, 2008 and December 31, 2007:

	September 30, 2008		December 31, 2007	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible assets:				
Downstream Segment:				
Transportation agreements	$ 1,000	$ (395)	$ 1,000	$ (358)
Other	5,244	(652)	4,927	(325)
Subtotal	6,244	(1,047)	5,927	(683)
Upstream Segment:				
Transportation agreements	888	(380)	888	(335)
Other	11,255	(3,492)	10,005	(3,046)
Subtotal	12,143	(3,872)	10,893	(3,381)
Midstream Segment:				
Gathering agreements	239,649	(121,574)	239,649	(107,356)
Fractionation agreement	38,000	(19,950)	38,000	(18,525)
Other	306	(161)	306	(149)
Subtotal	277,955	(141,685)	277,955	(126,030)
Marine Services Segment:				
Customer relationship intangibles	51,320	(2,260)	--	--
Other	18,680	(3,108)	--	--
Subtotal	70,000	(5,368)	--	--
Total intangible assets	366,342	(151,972)	294,775	(130,094)
Excess investments: (1)				
Downstream Segment (2)	33,390	(25,012)	33,390	(21,861)
Upstream Segment (3)	26,908	(5,649)	26,908	(5,135)
Midstream Segment (4)	7,469	(193)	6,988	(95)
Subtotal	67,767	(30,854)	67,286	(27,091)
Total intangible assets, including excess investments	$ 434,109	$ (182,826)	$ 362,061	$ (157,185)

(1) Excess investments are included in “Equity Investments” in our consolidated balance sheets.
(2) Relates to our investment in Centennial.
(3) Relates to our investment in Seaway.
(4) Relates to our investment in Jonah.

The following table presents the amortization expense of our intangible assets by segment for the three months and nine months ended September 30, 2008 and 2007:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Intangible assets:				
Downstream Segment	$ 121	$ 191	$ 364	$ 490
Upstream Segment	192	157	491	497
Midstream Segment	5,299	5,566	15,655	16,747
Marine Services Segment	2,012	--	5,368	--
Subtotal	7,624	5,914	21,878	17,734
Excess investments: (1)				
Downstream Segment	1,117	1,897	3,151	3,490
Upstream Segment	171	171	514	514
Midstream Segment	33	29	98	62
Subtotal	1,321	2,097	3,763	4,066
Total amortization expense	$ 8,945	$ 8,011	$ 25,641	$ 21,800

(1) Amortization of excess investments is included in equity earnings.

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:

	Intangible Assets	Excess Investments
2008	$ 29,283	$ 5,895
2009	26,374	4,774
2010	24,516	1,031
2011	22,630	1,031
2012	17,158	1,031
2013	15,606	1,031

Goodwill

The following table presents the carrying amount of goodwill at September 30, 2008 and December 31, 2007, by business segment:

	September 30, 2008	December 31, 2007
Downstream Segment	$ 1,339	$ 1,339
Upstream Segment	14,771	14,167
Marine Services Segment	90,294	--
Total goodwill	$ 106,404	$ 15,506

NOTE 11. DEBT OBLIGATIONS

The following table summarizes the principal amounts outstanding under all of our debt instruments at September 30, 2008 and December 31, 2007:

	September 30, 2008	December 31, 2007
Short-term senior debt obligations:		
6.45% TE Products Senior Notes, due January 2008 (1)	$ --	$ 180,000
7.51% TE Products Senior Notes, due January 2028 (1)	--	175,000
Total principal amount of short-term senior debt obligations	--	355,000
Adjustment to carrying value associated with hedges of fair value and unamortized discounts (2)	--	(1,024)
Total short-term senior debt obligations	$ --	$ 353,976
Long-term:		
Senior debt obligations: (3)		
Revolving Credit Facility, due December 2012	$ 324,717	$ 490,000
7.625% Senior Notes, due February 2012	500,000	500,000
6.125% Senior Notes, due February 2013	200,000	200,000
5.90% Senior Notes, due April 2013	400,000	--
6.65% Senior Notes, due April 2018	350,000	--
7.55% Senior Notes, due April 2038	250,000	--
Total principal amount of long-term senior debt obligations	2,024,717	1,190,000
7.000% Junior Subordinated Notes, due June 2067 (3)	300,000	300,000
Total principal amount of long-term debt obligations	2,324,717	1,490,000
Adjustment to carrying value associated with hedges of fair value and unamortized discounts (4)	14,028	21,083
Total long-term debt obligations	2,338,745	1,511,083
Total Debt Instruments (4)	$ 2,338,745	$ 1,865,059
Standby letters of credit outstanding (5)	$ --	$ 23,494

(1) In January 2008, TE Products retired all of its outstanding debt by repaying at maturity $180.0 million principal amount of its 6.45% TE Products Senior Notes due 2008 and redeeming the remaining $175.0 million principal amount of its 7.51% TE Products Senior Notes due 2028. The redemption price for the 7.51% TE Products Senior Notes due 2028 was 103.755% (or $181.6 million, which included a $6.6 million make-whole premium) of the principal amount plus accrued and unpaid interest to January 28, 2008, the date of redemption, of $0.5 million.

(2) Includes $1.0 million related to fair value hedges and $2 thousand in unamortized discount. In January 2008, with the redemption of the 7.51% TE Products Senior Notes, the remaining unamortized loss was recognized in the statement of consolidated income.

(3) TE Products, TCTM, TEPPCO Midstream and Val Verde (collectively, the "Subsidiary Guarantors") have issued full, unconditional, joint and several guarantees of our senior notes, junior subordinated notes and revolving credit facility.

(4) From time to time we enter into interest rate swap agreements to hedge our exposure to changes in the fair value on a portion of the debt obligations presented above (see Note 5). At September 30, 2008 and December 31, 2007, amount includes $5.4 million and $2.1 million of unamortized discounts, respectively, and $19.4 million and $23.2 million related to fair value hedges, respectively.

(5) Letters of credit were issued in connection with crude oil purchased during the respective quarter. Payables related to these purchases of crude oil are generally paid during the following quarter.

Revolving Credit Facility

We have in place an unsecured revolving credit facility ("Revolving Credit Facility"), which matures on December 12, 2012. The Revolving Credit Facility allows us to request unlimited one-year extensions of the maturity date, subject to lender approval and satisfaction of certain other conditions. In July 2008, we received confirmations from participating lenders making effective our exercise of the accordion feature under the facility, and increased the bank commitments thereunder from $700.0 million to $950.0 million. The aggregate outstanding principal amount of swing line loans or same day borrowings permitted under the Revolving Credit Facility is $40.0 million. The interest rate is based, at our option, on either the lender's base rate, or LIBOR rate, plus a margin, in effect at the time of the borrowings. The applicable margin with respect to LIBOR rate borrowings is based on our senior unsecured non-credit enhanced long-term debt rating issued by Standard & Poor's Rating Services ("S&P") and Moody's Investors Service, Inc. ("Moody's"). The Revolving Credit Facility contains a term-out option in which we may, on the maturity date, convert the principal balance of all revolving loans then outstanding into a non-revolving one-year term loan. Upon the conversion of the revolving loans to term loans pursuant to the term-out option, the applicable LIBOR spread will increase by 0.125% per year, and if immediately prior to such borrowing the total outstanding revolver borrowings then outstanding exceeds 50% of the total lender commitments, the applicable LIBOR spread with respect to borrowings will increase by an additional 10 basis points.

During September 2008, Lehman Brothers Bank, FSB ("Lehman"), which had a 4.05% participation in our Revolving Credit Facility, stopped funding its commitment following the bankruptcy filing of its parent. Assuming that future fundings are not received for the Lehman percentage commitment, aggregate available capacity would be reduced by approximately $38.5 million.

The Revolving Credit Facility contains financial covenants that require us to maintain a ratio of Consolidated Funded Debt to Pro Forma EBITDA (as defined and calculated in the facility) of less than 5.00 to 1.00 (and, if after giving effect to a permitted acquisition the ratio exceeds 5.00 to 1.00, the threshold ratio will be increased to 5.50 to 1.00 for the fiscal quarter in which such acquisition occurs and the first full fiscal quarter following such acquisition). Other restrictive covenants in the Revolving Credit Facility limit our ability, and the ability of certain of our subsidiaries, to, among other things, incur certain additional indebtedness, make distributions in excess of Available Cash (see Note 12), incur certain liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets. The credit agreement restricts the amount of outstanding debt of the Jonah joint venture to debt owing to the owners of its partnership interests and other third-party debt in the aggregate principal amount of $50.0 million and allows for the issuance of certain hybrid securities of up to 15% of our Consolidated Total Capitalization (as defined therein). In September 2008, we used proceeds from our equity offering (see Note 12) to repay a portion of the then outstanding balance of the Revolving Credit Facility. At September 30, 2008, $324.7 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 3.56%, and our available borrowing capacity under the facility was approximately $600.0 million. At September 30, 2008, we were in compliance with the covenants of the Revolving Credit Facility.

Senior Notes

On January 27, 1998, TE Products issued $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"). Interest on the TE Products Senior Notes was payable semiannually in arrears on January 15 and July 15 of each year. The 6.45% TE Products Senior Notes were issued at a discount of $0.3 million and were being accreted to their face value over the term of the notes. The 6.45% TE Products Senior Notes due 2008 were redeemed at maturity on January 15, 2008. The 7.51% TE Products Senior Notes due 2028, issued at par, became redeemable at any time after January 15, 2008, at the option of TE Products, in whole or in part, at varying fixed annual redemption prices. In October 2007, TE Products repurchased $35.0 million principal amount of the 7.51% TE Products Senior Notes for $36.1 million and accrued interest. On January 28, 2008, TE Products redeemed the remaining $175.0

million of 7.51% TE Products Senior Notes at a redemption price of 103.755% of the principal amount plus accrued and unpaid interest at the date of redemption. We funded the retirement of both series of senior notes with borrowings under our term credit agreement.

On February 20, 2002 and January 30, 2003, we issued $500.0 million principal amount of 7.625% Senior Notes due 2012 and $200.0 million principal amount of 6.125% Senior Notes due 2013, respectively. These senior notes were issued at discounts of $2.2 million and $1.4 million, respectively, and are being accreted to their face value over the applicable term of the senior 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.

On March 27, 2008, we issued (i) $250.0 million principal amount of 5.90% Senior Notes due 2013, (ii) $350.0 million principal amount of 6.65% Senior Notes due 2018, and (iii) $400.0 million principal amount of 7.55% Senior Notes due 2038. The senior notes were issued at discounts of $0.2 million, $1.3 million and $2.2 million, respectively, and are being accreted to their face value over the applicable terms of the senior 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 50 basis points.

The indentures governing our senior notes contain covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indentures do not limit our ability to incur additional indebtedness. At September 30, 2008, we were in compliance with the covenants of our senior notes.

Junior Subordinated Notes

In May 2007, we issued and sold $300.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due June 1, 2067 ("Junior Subordinated Notes"). Our payment obligations under the Junior Subordinated Notes are subordinated to all of our current and future senior indebtedness (as defined in the related indenture). The Subsidiary Guarantors have issued full, unconditional, and joint and several guarantees, on a junior subordinated basis, of payment of the principal of, premium, if any, and interest on the Junior Subordinated Notes.

The indenture governing the Junior Subordinated Notes does not limit our ability to incur additional debt, including debt that ranks senior to or equally with the Junior Subordinated Notes. The indenture allows us to defer interest payments on one or more occasions for up to ten consecutive years, subject to certain conditions. The indenture also provides that during any period in which we defer interest payments on the Junior Subordinated Notes, subject to certain exceptions, (i) we cannot declare or make any distributions with respect to, or redeem, purchase or make a liquidation payment with respect to, any of our equity securities; (ii) neither we nor the Subsidiary Guarantors will make, and we and the Subsidiary Guarantors will cause our respective majority-owned subsidiaries not to make, any payment of interest, principal or premium, if any, on or repay, purchase or redeem any of our or the Subsidiary Guarantors' debt securities (including securities similar to the Junior Subordinated Notes) that contractually rank equally with or junior to the Junior Subordinated Notes or the guarantees, as applicable; and (iii) neither we nor the Subsidiary Guarantors will make, and we and the Subsidiary Guarantors will cause our respective majority-owned subsidiaries not to make, any payments under a guarantee of debt securities (including under a guarantee of debt securities that are similar to the Junior Subordinated Notes) that contractually ranks equally with or junior to the Junior Subordinated Notes or the guarantees, as applicable.

The Junior Subordinated Notes bear interest at a fixed annual rate of 7.000% from May 2007 to June 1, 2017, payable semi-annually in arrears on June 1 and December 1 of each year, commencing December 1, 2007.

After June 1, 2017, the Junior Subordinated Notes will bear interest at a variable annual rate equal to the 3-month LIBOR rate for the related interest period plus 2.7775%, payable quarterly in arrears on March 1, June 1, September 1 and December 1 of each year commencing September 1, 2017. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to certain provisions. Deferred interest will accumulate additional interest at the then-prevailing interest rate on the Junior Subordinated Notes. The Junior Subordinated Notes mature in June 2067. The Junior Subordinated Notes are redeemable in whole or in part prior to June 1, 2017 for a “make-whole” redemption price and thereafter at a redemption price equal to 100% of their principal amount plus accrued interest. The Junior Subordinated Notes are also redeemable prior to June 1, 2017 in whole (but not in part) upon the occurrence of certain tax or rating agency events at specified redemption prices. At September 30, 2008, we were in compliance with the covenants of the Junior Subordinated Notes.

In connection with the issuance of the Junior Subordinated Notes, we and our Subsidiary Guarantors entered into a replacement capital covenant in favor of holders of a designated series of senior long-term indebtedness (as provided in the underlying documents) pursuant to which we and our Subsidiary Guarantors agreed for the benefit of such debt holders that we would not redeem or repurchase or otherwise satisfy, discharge or defease any of the Junior Subordinated Notes on or before June 1, 2037, unless, subject to certain limitations, during the 180 days prior to the date of that redemption, repurchase, defeasance or purchase, we have or one of our subsidiaries has received a specified amount of proceeds from the sale of qualifying securities that have characteristics that are the same as, or more equity-like than, the applicable characteristics of the Junior Subordinated Notes. The replacement capital covenant is not a term of the indenture or the Junior Subordinated Notes.

Term Credit Agreement

We had in place a senior unsecured term credit agreement (“Term Credit Agreement”), with a borrowing capacity of $1.0 billion and a maturity date of December 19, 2008. During the first quarter of 2008, we borrowed $1.0 billion under the Term Credit Agreement to finance the retirement of TE Products’ senior notes and the Cenac and Horizon acquisitions and for other partnership purposes. In March 2008, we repaid the outstanding balance of the Term Credit Agreement with proceeds from the issuance of senior notes and other cash on hand and terminated the agreement.

Debt Obligations of Unconsolidated Affiliates

We have one unconsolidated affiliate, Centennial, with long-term debt obligations. The following table shows the total debt of Centennial at September 30, 2008 (on a 100% basis) and the corresponding scheduled maturities of such debt.

	Scheduled Maturities of Debt
2008	$ 2,550
2009	9,900
2010	9,100
2011	9,000
2012	8,900
After 2012	93,000
Total scheduled maturities of debt	$ 132,450

At September 30, 2008 and December 31, 2007, Centennial’s debt obligations consisted of $132.5 million and $140.0 million, respectively, borrowed under a master shelf loan agreement. Borrowings under the master shelf agreement mature in May 2024 and are collateralized by substantially all of Centennial’s assets and severally guaranteed by Centennial’s owners. In January 2008, we entered into an amended and restated guaranty agreement

("Amended Guaranty") in which we, TCTM, TEPPCO Midstream and TE Products (collectively, "TEPPCO Guarantors") are required, on a joint and several basis, to pay 50% of any past-due amount under Centennial's master shelf loan agreement not paid by Centennial (see Note 16).

NOTE 12. PARTNERS' CAPITAL AND DISTRIBUTIONS

Our Units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Partnership Agreement. We are managed by our General Partner.

In accordance with the Partnership Agreement, capital accounts are maintained for our General Partner and limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our consolidated financial statements. In connection with the amendment of our Partnership Agreement in December 2006, the General Partner's obligation to make capital contributions to maintain its 2% capital account was eliminated.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and General Partner will receive. 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 GAAP in our financial statements.

Equity Offerings and Registration Statements

In general, the Partnership Agreement authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as may be established by our General Partner in its sole discretion (subject, under certain circumstances, to the approval of our unitholders).

In September 2008, we filed a universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities and removed from registration securities remaining under our previous universal shelf registration statement.

On September 9, 2008, we issued and sold in an underwritten public offering 9.2 million Units at a price to the public of $29.00 per Unit, including 1.2 million Units sold upon exercise of the underwriters' over-allotment option granted in connection with the offering. The proceeds from the offering, net of underwriting discount and offering expenses, totaled approximately $257.0 million. Concurrently with this offering, we sold 241,380 unregistered Units at the public offering price of $29.00 to TEPPCO Unit, an affiliate of EPCO in which certain EPCO employees who perform services for us, including the executive officers named in the Executive Compensation section of our recent Annual Report on Form 10-K, were issued Class B limited partner interests to incentivize them to enhance the long-term value of our Units. The net proceeds from the offering and the unregistered issuance to TEPPCO Unit were used to reduce indebtedness under our Revolving Credit Facility. For additional information regarding TEPPCO Unit and the equity-based compensatory awards issued therein, please see Note 3.

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 shown in the following table:

	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%
Over First Target – Cash distributions greater than $0.325 per Unit	75%	25%

The following table reflects the allocation of total distributions paid during the nine months ended September 30, 2008 and 2007.

	For the Nine Months Ended September 30, 2008	2007
Limited Partner Units	$ 197,291	$ 183,693
General Partner Ownership Interest	4,026	3,749
General Partner Incentive	35,458	32,171
Total Cash Distributions Paid	$ 236,775	$ 219,613
Total Cash Distributions Paid Per Unit	$ 2.115	$ 2.045

Our quarterly cash distributions for 2008 are presented in the following table:

	Cash Distribution History: Distribution per Unit	Record Date	Payment Date
1st Quarter 2008	$ 0.7100	Apr. 30, 2008	May 7, 2008
2nd Quarter 2008	$ 0.7100	Jul. 31, 2008	Aug. 7, 2008
3rd Quarter 2008 (1)	$ 0.7250	Oct. 31, 2008	Nov. 6, 2008

(1) The third quarter 2008 cash distribution totaled approximately $91.2 million.

EPCO, Inc. TPP Employee Unit Purchase Plan

The EPCO, Inc. TPP Employee Unit Purchase Plan (the "Unit Purchase Plan") provides for discounted purchases of our Units by employees of EPCO and its affiliates. A maximum of 1,000,000 Units may be delivered under the Unit Purchase Plan (subject to adjustment as provided in the plan). The Unit Purchase Plan is effective until December 8, 2016, or, if earlier, at the time that all available Units under the plan have been purchased on behalf of the participants or the time of termination of the plan by EPCO or the Chairman or Vice Chairman of EPCO. As of September 30, 2008, 21,009 Units have been issued to employees under this plan.

Distribution Reinvestment Plan

Our distribution reinvestment plan ("DRIP") provides for the issuance of up to 10,000,000 Units. Units purchased through the DRIP may be acquired at a discount rating from 0% to 5% (currently set at 5%), which will be set from time to time by us. As of September 30, 2008, 245,084 Units have been issued in connection with the DRIP.

General Partner's Interest

At September 30, 2008 and December 31, 2007, we had deficit balances of $100.7 million and $88.0 million, respectively, in our General Partner's equity account. These negative balances do not represent assets to us and do not represent obligations of the General Partner to contribute cash or other property to us. The General Partner's equity account generally consists of its cumulative share of our net income less cash distributions made to it plus capital contributions that it has made to us (see our Statement of Consolidated Partners' Capital for a detail of the General Partner's equity account). For the nine months ended September 30, 2008, our General Partner was allocated $26.7 million (representing 16.83%) of our net income and received $39.5 million in cash distributions.

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 previous years, resulted in a deficit in the General Partner's equity account at December 31, 2007 and September 30, 2008. Future cash distributions that exceed net income will result in an increase in the deficit balance in the General Partner's equity account.

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

Accumulated Other Comprehensive Income (Loss)

SFAS No. 130, *Reporting Comprehensive Income* requires certain items such as foreign currency translation adjustments, gains or losses associated with pension or other postretirement benefits, prior service costs or credits associated with pension or other postretirement benefits, transition assets or obligations associated with pension or other postretirement benefits and unrealized gains and losses on certain investments in debt and equity securities to be reported in a financial statement. As of and for the nine months ended September 30, 2008, the components of accumulated other comprehensive income (loss) reflected on our consolidated balance sheet were composed of crude oil hedges and treasury locks. The majority of these crude oil hedges have forward positions that expire during 2008, with the remainder expiring during 2009. 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 (loss) until they are recognized in net income in future periods upon the contract expiration. The amounts related to settlements of treasury lock agreements are being amortized into earnings over the terms of the respective debt (see Note 5).

The accumulated balance of other comprehensive income (loss) is as follows:

Balance at December 31, 2007	$ (42,557)
Changes in fair values of crude oil cash flow hedges	15,466
Settlement of treasury locks	(52,098)
Amortization of treasury lock proceeds into earnings	(80)
Changes in fair values of treasury locks	25,296
Ineffectiveness of treasury locks	42
Transfer portion of interest payment hedged under treasury locks not occurring as forecasted to earnings	3,586
Balance at September 30, 2008	$ (50,345)

NOTE 13. BUSINESS SEGMENTS

We have four reporting segments:

§ Our Downstream Segment, which is engaged in the pipeline transportation, marketing and storage of refined products, LPGs and petrochemicals;
§ Our Upstream Segment, which is engaged in the gathering, pipeline transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals;
§ Our Midstream Segment, which is engaged in the gathering of natural gas, fractionation of NGLs and pipeline transportation of NGLs; and
§ Our Marine Services Segment, which is engaged in the marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges.

The amounts indicated below as “Partnership and Other” for income and expense items (including operating income) relate primarily to intersegment eliminations from activities among our reporting segments. Amounts indicated below as “Partnership and Other” for assets and capital expenditures include the elimination of intersegment related party receivables and investment balances among our reporting segments and assets that we hold that have not been allocated to any of our reporting segments (including such items as corporate furniture and fixtures, vehicles, computer hardware and software, prepaid insurance and unamortized debt issuance costs on debt issued at the Partnership level).

Our Downstream Segment revenues are earned from pipeline transportation, marketing and storage of refined products and LPGs, intrastate pipeline transportation of petrochemicals, sale of product inventory and other ancillary services. We generally realize higher revenues in the Downstream Segment during the first and fourth quarters of each year since LPGs volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating. 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, although recent high gasoline prices have moderated this trend somewhat. The two largest operating expense items of the Downstream Segment are labor and electric power. 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 investment in Centennial (see Note 8).

Our Upstream Segment revenues are earned from gathering, pipeline transporting, marketing and storing crude oil and distributing lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating crude oil purchased at the lease along our pipeline systems, and 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. Revenues are also generated from trade documentation and terminaling services, primarily at Cushing, Oklahoma, and Midland, Texas. Our Upstream Segment also includes our equity investments in Seaway and Texas Offshore Port System (see Note 8). The Seaway system 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. Seaway also has a connection to our South Texas system that allows it to receive both onshore and offshore domestic crude oil in the Texas Gulf Coast area for delivery to Cushing. Texas Offshore Port System, a joint venture between us and affiliates of Enterprise Products Partners and Oiltanking, was formed to design, construct, operate and own a new Texas offshore crude oil port and pipeline system.

Our Midstream Segment revenues are earned from 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 from West Texas and New Mexico to Mont Belvieu; and the fractionation of NGLs in Colorado. Our Midstream Segment also includes our equity investment in Jonah (see Note 8). Jonah, a joint venture between us and an affiliate of Enterprise Products Partners, owns a natural gas gathering system in the Green River Basin in southwestern Wyoming.

Our Marine Services Segment revenues are earned from the marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges. We entered the marine transportation business in February 2008 with the acquisition of assets and certain intangible assets from Cenac and Horizon on February 1, 2008 and February 29, 2008, respectively (see Note 9). These businesses service refineries and storage terminals along the Mississippi, Illinois and Ohio rivers, the Intracoastal Waterway between Texas and Florida and the Tennessee-Tombigbee Waterway system. These assets also gather crude oil from production facilities and platforms along the U.S. Gulf Coast and in the Gulf of Mexico.

The following table presents our measurement of earnings before interest expense for the three months and nine months ended September 30, 2008 and 2007:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Total operating revenues	$ 4,205,744	$ 2,580,657	$ 11,194,695	$ 6,608,522
Less: Total costs and expenses	4,145,884	2,525,938	10,992,040	6,419,640
Operating income	59,860	54,719	202,655	188,882
Add: Gain on sale of ownership interest in MB Storage	--	(20)	--	59,628
Equity earnings	22,133	19,059	63,212	54,856
Interest income	289	454	880	1,241
Other income – net	106	306	905	1,085
Earnings before interest expense and provision for income taxes	$ 82,388	$ 74,518	$ 267,652	$ 305,692

A reconciliation of our earnings before interest expense and provision for income taxes to net income for the three months and nine months ended September 30, 2008 and 2007 is as follows:

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
Earnings before interest expense and provision for income taxes	$ 82,388	$ 74,518	$ 267,652	$ 305,692
Interest expense – net	(34,301)	(26,901)	(105,906)	(71,897)
Income before provision for income taxes	48,087	47,617	161,746	233,795
Provision for income taxes	1,056	(14)	2,894	213
Net income	$ 47,031	$ 47,631	$ 158,852	$ 233,582

The table below includes information by segment, together with reconciliations to our consolidated totals for the periods indicated:

	Downstream Segment	Upstream Segment	Midstream Segment	Marine Services Segment	Partnership and Other	Consolidated
Revenues from third parties:						
Three months ended September 30, 2008	$ 94,552	$ 4,032,177	$ 26,934	$ 46,018	$ --	$ 4,199,681
Three months ended September 30, 2007	83,393	2,464,750	27,672	--	--	2,575,815
Nine months ended September 30, 2008	264,209	10,712,443	80,727	119,590	--	11,176,969
Nine months ended September 30, 2007	257,858	6,254,605	81,464	--	--	6,593,927
Revenues from related parties:						
Three months ended September 30, 2008	$ 2,500	$ 207	$ 3,391	$ --	$ (35)	$ 6,063
Three months ended September 30, 2007	1,135	281	3,478	--	(52)	4,842
Nine months ended September 30, 2008	6,978	599	10,283	--	(134)	17,726
Nine months ended September 30, 2007	4,768	749	9,493	--	(415)	14,595
Intersegment and intrasegment revenues:						
Three months ended September 30, 2008	$ --	$ --	$ --	$ --	$ --	$ --
Three months ended September 30, 2007	--	--	--	--	--	--
Nine months ended September 30, 2008	--	--	--	--	--	--
Nine months ended September 30, 2007	--	80	--	--	(80)	--
Total revenues:						
Three months ended September 30, 2008	$ 97,052	$ 4,032,384	$ 30,325	$ 46,018	$ (35)	$ 4,205,744
Three months ended September 30, 2007	84,528	2,465,031	31,150	--	(52)	2,580,657
Nine months ended September 30, 2008	271,187	10,713,042	91,010	119,590	(134)	11,194,695
Nine months ended September 30, 2007	262,626	6,255,434	90,957	--	(495)	6,608,522
Depreciation and amortization:						
Three months ended September 30, 2008	$ 10,736	$ 5,096	$ 9,982	$ 6,257	$ --	$ 32,071
Three months ended September 30, 2007	11,282	5,133	10,071	--	--	26,486
Nine months ended September 30, 2008	31,474	14,842	29,573	16,345	--	92,234
Nine months ended September 30, 2007	34,142	13,349	30,244	--	--	77,735

	Downstream Segment	Upstream Segment	Midstream Segment	Marine Services Segment	Partnership and Other	Consolidated
Operating income:						
Three months ended September 30, 2008	$ 18,671	$ 26,903	$ 5,803	$ 8,354	$ 129	$ 59,860
Three months ended September 30, 2007	26,646	20,602	7,465	--	6	54,719
Nine months ended September 30, 2008	70,654	81,871	22,467	23,572	4,091	202,655
Nine months ended September 30, 2007	101,533	63,660	20,235	--	3,454	188,882
Equity earnings (losses):						
Three months ended September 30, 2008	$ (2,349)	$ 2,748	$ 21,863	$ --	$ (129)	$ 22,133
Three months ended September 30, 2007	(3,064)	1,073	21,056	--	(6)	19,059
Nine months ended September 30, 2008	(10,066)	9,925	67,444	--	(4,091)	63,212
Nine months ended September 30, 2007	(8,430)	4,310	62,430	--	(3,454)	54,856
Earnings before interest expense and provision for income taxes:						
Three months ended September 30, 2008	$ 16,500	$ 29,766	$ 27,763	$ 8,359	$ --	$ 82,388
Three months ended September 30, 2007	24,096	21,719	28,703	--	--	74,518
Nine months ended September 30, 2008	61,293	92,539	90,237	23,583	--	267,652
Nine months ended September 30, 2007	154,454	68,114	83,124	--	--	305,692
Segment assets:						
At September 30, 2008	$ 1,289,196	$ 2,527,885	$ 1,516,569	$ 636,508	$ 15,467	$ 5,985,625
At December 31, 2007	1,221,316	2,084,830	1,512,621	--	(68,710)	4,750,057
Capital expenditures:						
At September 30, 2008	$ 158,293	$ 22,306	$ 3,964	$ 23,600	$ 6,999	$ 215,162
At December 31, 2007	165,353	54,583	7,412	--	924	228,272
Investments in unconsolidated affiliates:						
At September 30, 2008	$ 64,888	$ 196,173	$ 921,219	$ --	$ 9,097	$ 1,191,377
At December 31, 2007	79,324	188,650	879,021	--	--	1,146,995
Intangible assets:						
At September 30, 2008	$ 5,197	$ 8,271	$ 136,270	$ 64,632	$ --	$ 214,370
At December 31, 2007	5,244	7,512	151,925	--	--	164,681
Goodwill:						
At September 30, 2008	$ 1,339	$ 14,771	$ --	$ 90,294	$ --	$ 106,404
At December 31, 2007	1,339	14,167	--	--	--	15,506

NOTE 14. RELATED PARTY TRANSACTIONS

The following table summarizes related party transactions for the three months and nine months ended September 30, 2008 and 2007:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Revenues from EPCO and affiliates:				
Sales of petroleum products (1)	$ 181	$ 91	$ 485	$ 196
Transportation – NGLs (2)	3,391	3,478	10,182	9,493
Transportation – LPGs (3)	1,392	695	4,691	2,968
Transportation – Refined products	--	61	--	105
Other operating revenues (4)	1,077	301	2,302	1,508
Revenues from unconsolidated affiliates:				
Other operating revenues (5)	22	216	66	325
Related party revenues	$ 6,063	$ 4,842	$ 17,726	$ 14,595
Costs and Expenses from EPCO and affiliates:				
Purchases of petroleum products (6)	$ 51,443	$ 17,133	$ 101,668	$ 40,373
Operating expense (7)	27,132	24,126	75,392	72,890
General and administrative (8)	7,340	6,568	24,117	19,150
Costs and Expenses from unconsolidated affiliates:				
Purchases of petroleum products (9)	1,845	2,341	5,387	2,341
Operating expense (10)	1,122	2,701	5,023	6,363
Costs and Expenses from Cenac and affiliates:				
Operating expense (11)	13,810	--	32,327	--
Related party expenses	$ 102,692	$ 52,869	$ 243,914	$ 141,117

(1) Includes sales from TE Products and Lubrication Services, LLC (“LSI”) to Enterprise Products Partners and certain of its subsidiaries.
(2) Includes revenues from NGL transportation on the Chaparral and Panola NGL pipelines from Enterprise Products Partners and certain of its subsidiaries.
(3) Includes revenues from LPG transportation on the TE Products pipeline from Enterprise Products Partners and certain of its subsidiaries.
(4) Includes other operating revenues on the TE Products pipeline and the Val Verde system from Enterprise Products Partners and certain of its subsidiaries.
(5) Includes sales of petroleum products, management fees and rental revenues from Centennial, Jonah and Seaway.
(6) Includes TCO purchases of condensate of $46.8 million, $12.6 million, $88.3 million and $28.2 million from Enterprise Products Partners and certain of its subsidiaries for the three months and nine months ended September 30, 2008 and 2007, respectively, and expenses related to TCO’s and LSI’s use of an affiliate of EPCO as a transporter.
(7) Includes operating payroll, payroll related expenses and other operating expenses, including reimbursements related to employee benefits and employee benefit plans, incurred by EPCO in managing us and our subsidiaries in accordance with the ASA. Also includes insurance expense for the three months and nine months ended September 30, 2008 and 2007, of $2.7 million, $2.8 million, $7.8 million and $11.6 million, respectively, related to premiums paid by EPCO on our behalf. The majority of our insurance coverage, including property, liability, business interruption, auto and directors’ and officers’ liability insurance, is obtained through EPCO.
(8) Includes administrative payroll, payroll related expenses and other administrative expenses, including reimbursements related to employee benefits and employee benefit plans, incurred by EPCO in managing and operating us and our subsidiaries in accordance with the ASA.
(9) Includes TCO purchases of petroleum products from Jonah and Seaway and pipeline transportation expense from Seaway.
(10) Includes rental expense and other operating expense.

(11) Includes reimbursement for operating payroll, payroll related expenses, certain repairs and maintenance expenses and insurance premiums on our equipment, as well as payment of a $42 thousand monthly service fee and a 5% overhead fee charged on direct costs incurred by Cenac to operate the marine assets in accordance with the transitional operating agreement with Cenac. In accordance with the transitional operating agreement, our fleet of acquired tow boats and tank barges (including those acquired from Horizon) are operated by employees of Cenac for a period of up to two years following the acquisition.

The following table summarizes the related party balances at September 30, 2008 and December 31, 2007:

	September 30, 2008	December 31, 2007
Accounts receivable, related parties (1)	$ 6,410	$ 6,525
Accounts payable, related parties (2)	38,940	38,980

(1) Relates to sales and transportation services provided to Enterprise Products Partners and certain of its subsidiaries and EPCO and certain of its affiliates and direct payroll, payroll related costs and other operational expenses charged to unconsolidated affiliates.
(2) Relates to direct payroll, payroll related costs and other operational related charges from Enterprise Products Partners and certain of its subsidiaries, EPCO and certain of its affiliates and Cenac and affiliates, and transportation and other services provided by unconsolidated affiliates and advances from Seaway for operating expenses.

We are affiliated with EPCO and other companies controlled by Mr. Duncan, and our transactions and agreements with them are not necessarily on an arm's length basis. As a result, we cannot provide assurance that the terms and provisions of such transactions or agreements are at least as favorable to us as we could have obtained from unaffiliated third parties.

Relationship with EPCO and Affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities:

§ EPCO and its consolidated private company subsidiaries;
§ Texas Eastern Products Pipeline Company, LLC, our General Partner;
§ Enterprise GP Holdings, which owns and controls our General Partner;
§ Enterprise Products Partners, which is controlled by affiliates of EPCO, including Enterprise GP Holdings;
§ Duncan Energy Partners, which is controlled by affiliates of EPCO;
§ Enterprise Gas Processing LLC, which is controlled by affiliates of EPCO and is our joint venture partner in Jonah;
§ Enterprise Offshore Port System, LLC, which is controlled by affiliates of EPCO and is one of our joint venture partners in Texas Offshore Port System; and
§ TEPPCO Unit (see Note 3).

Dan L. Duncan directly owns and controls EPCO and, through Dan Duncan LLC, owns and controls EPE Holdings, LLC, the general partner of Enterprise GP Holdings. Enterprise GP Holdings owns all of the membership interests of our General Partner. The principal business activity of our General Partner is to act as our managing partner. The executive officers of our General Partner are employees of EPCO (see Note 1).

We and our General Partner are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are separate from those of EPCO and its other affiliates. EPCO and its consolidated private company subsidiaries and affiliates depend on the cash distributions they receive from our General Partner and other investments to fund their operations and to meet their debt obligations. We paid cash distributions to our General Partner of $39.5 million and $35.9 million during the nine months ended September 30, 2008 and 2007, respectively.

The limited partner interests in us that are owned or controlled by EPCO and certain of its affiliates, other than those interests owned by Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of an affiliate of EPCO. All of the membership interests in our General Partner and the limited partner interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. If Enterprise GP Holdings were to default under its credit facility, its lender banks could own our General Partner.

EPCO Administrative Services Agreement

We do not have any employees. We are managed by our General Partner, and all of our management, administrative and operating functions are performed by employees of EPCO, pursuant to the ASA or by other service providers. We, Enterprise Products Partners, Duncan Energy Partners, Enterprise GP Holdings and our respective general partners are parties to the ASA. The ACG Committees of each general partner have approved the ASA.

Under the ASA, we reimburse EPCO for all costs and expenses it incurs in providing management, administrative and operating services for us, including compensation of employees (i.e., salaries, medical benefits and retirement benefits) (see Note 1). Since the vast majority of such expenses are charged to us on an actual basis (i.e., no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a standalone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis.

Jonah Joint Venture

Enterprise Products Partners (through an affiliate) is our joint venture partner in Jonah, the partnership through which we have owned our interest in the system serving the Jonah and Pinedale fields. Through September 30, 2008, we have reimbursed Enterprise Products Partners $303.9 million ($42.3 million in 2008, $152.2 million in 2007 and $109.4 million in 2006) for our share of the Phase V cost incurred by it (including its cost of capital incurred prior to the formation of the joint venture of $1.3 million). At September 30, 2008 and December 31, 2007, we had payables to Enterprise Products Partners for costs incurred of $1.3 million and $9.9 million, respectively (see Note 8). At September 30, 2008 and December 31, 2007, we had receivables from Jonah of $4.6 million and $6.0 million, respectively, for operating expenses. During the nine months ended September 30, 2008 and 2007, we received distributions from Jonah of $111.6 million and $77.3 million, respectively. The 2007 amount included $11.6 million of distributions declared in 2006 and paid during the first quarter of 2007. During the nine months ended September 30, 2008 and 2007, Jonah paid distributions of $26.8 million and $4.0 million, respectively, to the affiliate of Enterprise Products Partners that is our joint venture partner.

We have agreed to indemnify Enterprise Products Partners from any and all losses, claims, demands, suits, liability, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the formation of the Jonah joint venture, Jonah’s ownership or operation of the Jonah-Pinedale system prior to the effective date of the joint venture, and any environmental activity, or violation of or liability under environmental laws arising from or related to the condition of the Jonah-Pinedale system prior to the effective date of the joint venture. In general, a claim for indemnification cannot be filed until the losses suffered by Enterprise Products Partners exceed $1.0 million, and the maximum potential amount of future payments under the indemnity is limited to $100.0 million. However, if certain representations or warranties are breached, the maximum potential amount of future payments under the indemnity is capped at $207.6 million. All indemnity payments are net of insurance recoveries that Enterprise Products Partners may receive from third-party insurers. We carry insurance coverage that may offset any payments required under the indemnity. We do not expect that these indemnities will have a material adverse effect on our financial position, results of operations or cash flows.

Texas Offshore Port System Joint Venture

Enterprise Products Partners (through an affiliate) is one of our joint venture partners in Texas Offshore Port System (see Note 8). Through September 30, 2008, we have a payable of $2.3 million for our contribution to our investment in Texas Offshore Port System, which will be paid in the fourth quarter of 2008.

Sale of General Partner to Enterprise GP Holdings; Relationship with Energy Transfer Equity

On May 7, 2007, all of the membership interests in our General Partner, together with 4,400,000 of our Units, were sold by DFIGP to Enterprise GP Holdings, a publicly traded partnership also controlled indirectly by Dan L. Duncan. As of May 7, 2007, Enterprise GP Holdings owns and controls the 2% general partner interest in us and has the right (through its 100% ownership of our General Partner) to receive the incentive distribution rights associated with the general partner interest. Enterprise GP Holdings, DFIGP and other entities controlled by Mr. Duncan own 16,950,130 of our Units.

Concurrently with the acquisition of our General Partner, Enterprise GP Holdings acquired non-controlling ownership interests, accounted for as equity method investments, in Energy Transfer Equity, L.P. ("Energy Transfer Equity") and LE GP, LLC, the general partner of Energy Transfer Equity.

Other Transactions

On January 23, 2007, we sold a 10-mile, 18-inch segment of pipeline to an affiliate of Enterprise Products Partners for approximately $8.0 million in cash. These assets were part of our Downstream Segment and had a net book value of approximately $2.5 million. The sales proceeds were used to fund construction of a replacement pipeline in the area, in which the new pipeline provides greater operational capability and flexibility. We recognized a gain of approximately $5.5 million on this transaction (see Note 9).

Relationship with Unconsolidated Affiliates

Our significant related party revenues and expense transactions with unconsolidated affiliates consist of management, rental and other revenues, transportation expense related to movements on Centennial and Seaway and rental expense related to the lease of pipeline capacity on Centennial. For additional information regarding our unconsolidated affiliates, see Note 8.

See "Jonah Joint Venture" and "Texas Offshore Port System Joint Venture" within this Note 14 for descriptions of ongoing transactions involving our Jonah and Texas Offshore Port System joint ventures with Enterprise Products Partners.

NOTE 15. EARNINGS PER UNIT

Basic earnings per Unit is computed by dividing net income or loss allocated to limited partner interests by the weighted average number of distribution-bearing Units outstanding during a period. The amount of net income allocated to limited partner interests is derived by subtracting our General Partner's share of the net income from net income. Our 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 12). Diluted earnings per Unit is computed by dividing net income or loss allocated to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing Units outstanding during a period (as used in determining basic earnings per Unit); and (ii) the number of incremental Units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net operating losses, restricted units and incremental option units are excluded from the calculation of diluted earnings per Unit due to their anti-dilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase Units at an average market value during the period. The amount of Units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities. In May 2007 and 2008, we granted 155,000 and 200,000 unit options, respectively, to employees providing services to us (see Note 3).

The following table shows the computation of basic and diluted earnings per Unit for the three months and nine months ended September 30, 2008 and 2007:

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
Net income	$ 47,031	$ 47,631	$ 158,852	$ 233,582
General Partner interest in net income	17.06%	16.47%	16.83%	16.47%
Earnings allocated to General Partner	$ 8,024	$ 7,975	$ 26,741	$ 38,476
BASIC EARNINGS PER UNIT:				
Numerator:				
Limited partners' interest in net income	$ 39,007	$ 39,656	$ 132,111	$ 195,106
Denominator:				
Units	97,158	89,806	95,035	89,805
Time-vested restricted units	158	62	110	30
Total Weighted average Units outstanding	97,316	89,868	95,145	89,835
Basic earnings per Unit:				
Limited partners' interest in net income	$ 0.40	$ 0.44	$ 1.39	$ 2.17
DILUTED EARNINGS PER UNIT:				
Numerator:				
Limited partners' interest in net income	$ 39,007	$ 39,656	$ 132,111	$ 195,106
Denominator:				
Units	97,158	89,806	95,035	89,805
Time-vested restricted units	158	62	110	30
Incremental option units	--	--	--	--
Total Weighted average Units outstanding	97,316	89,868	95,145	89,835
Diluted earnings per Unit:				
Limited partners' interest in net income	$ 0.40	$ 0.44	$ 1.39	$ 2.17

Our General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase, in accordance with our Partnership Agreement. At September 30, 2008 and 2007, we had outstanding 104,524,501 and 89,868,586 Units, respectively.

NOTE 16. COMMITMENTS AND CONTINGENCIES

Litigation

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 pursued certification as a class and have significantly increased their demand to approximately $175.0 million. 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.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of our other unitholders, and derivatively on our behalf, concerning proposals made to our unitholders in our definitive proxy statement filed with the SEC on September 11, 2006 ("Proxy Statement") and other transactions involving us and Enterprise Products Partners or its affiliates. Mr. Brinckerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants the General Partner; the Board of Directors of the General Partner; EPCO; Enterprise Products Partners and certain of its affiliates and Dan L. Duncan. We are named as a nominal defendant.

The amended complaint alleges, among other things, that certain of the transactions adopted at a special meeting of our unitholders on December 8, 2006, including a reduction of the General Partner's maximum percentage interest in our distributions in exchange for Units (the "Issuance Proposal"), were unfair to our unitholders and constituted a breach by the defendants of fiduciary duties owed to our unitholders and that the Proxy Statement failed to provide our unitholders with all material facts necessary for them to make an informed decision whether to vote in favor of or against the proposals. The amended complaint further alleges that, since Mr. Duncan acquired control of the General Partner in 2005, the defendants, in breach of their fiduciary duties to us and our unitholders, have caused us to enter into certain transactions with Enterprise Products Partners or its affiliates that were unfair to us or otherwise unfairly favored Enterprise Products Partners or its affiliates over us. The amended complaint alleges that such transactions include the Jonah joint venture entered into by us and an Enterprise Products Partners affiliate in August 2006 (citing the fact that our ACG Committee did not obtain a fairness opinion from an independent investment banking firm in approving the transaction), and the sale by us to an Enterprise Products Partners' affiliate of the Pioneer plant in March 2006. As more fully described in the Proxy Statement, the ACG Committee recommended the Issuance Proposal for approval by the Board of Directors of the General Partner. The amended complaint also alleges that Richard S. Snell, Michael B. Bracy and Murray H. Hutchison, constituting the three members of the ACG Committee at the time, cannot be considered independent because of their alleged ownership of securities in Enterprise Products Partners and its affiliates and/or their relationships with Mr. Duncan.

The amended complaint seeks relief (i) awarding damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the complaint; (ii) rescinding all actions taken pursuant to the Proxy vote and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts.

In addition to the proceedings 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 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 pipelines and other 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 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 September 30, 2008 and December 31, 2007, we had accrued liabilities of $7.1 million and $4.0 million, respectively, related to sites requiring environmental remediation activities.

In 1999, our Arcadia, Louisiana, facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of environmental contamination. Effective March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility. This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility. At September 30, 2008, we have an accrued liability of $0.6 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.

We are 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.

The FERC, pursuant to the Interstate Commerce Act of 1887, as amended, the Energy Policy Act of 1992 and rules and orders promulgated thereunder, 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 the 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 with interest 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. A successful challenge of our rates could adversely affect our revenues.

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.

The intrastate liquids pipeline transportation and gas gathering 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. 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 or if the states in which we operate adopt policies imposing more onerous regulation on gathering. Additional rules and legislation pertaining to these matters are considered and adopted from time to time at both state and federal levels. We cannot predict what effect, if any, such regulatory changes and legislation might have on our operations or revenues.

Operating Leases

We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. Total rental expense included in operating costs and expenses was $4.6 million, $4.0 million, $15.2 million and $17.6 million for the three months and nine months ended September 30, 2008 and 2007, respectively. There have been no material changes in our operating lease commitments since December 31, 2007.

Contractual Obligations

In March 2008, we issued $1.0 billion of senior notes due 2013, 2018 and 2038 (see Note 11). Other than the issuance of these senior notes, there have been no significant changes in our schedule of maturities of long-term debt or other contractual obligations since the year ended December 31, 2007.

The following table summarizes our maturities of long-term debt obligations at September 30, 2008:

	Payment or Settlement due by Period						
	Total	**2008**	**2009**	**2010**	**2011**	**2012**	**Thereafter**
Maturities of long-term debt (1)	$ 2,324,717	$ --	$ --	$ --	$ --	$ 824,717	$ 1,500,000
Interest payments (2)	$ 2,692,176	$ 154,584	$ 151,173	$ 151,173	$ 132,110	$ 97,761	$ 2,005,375

(1) We have long-term payment obligations under our Revolving Credit Facility, our senior notes and our Junior Subordinated Notes. Amounts shown in the table represent our scheduled future maturities of long-term debt principal for the periods indicated (see Note 11 for additional information regarding our consolidated debt obligations).
(2) Includes interest payments due on our senior notes and junior subordinated notes and interest payments and commitment fees due on our Revolving Credit Facility. The interest amount calculated on the Revolving Credit Facility and the junior subordinated notes is based on the assumption that the amount outstanding and the interest rate charged both remain at their current levels.

Other

Guarantees

At September 30, 2008 and December 31, 2007, Centennial's debt obligations consisted of $132.5 million and $140.0 million, respectively, borrowed under a master shelf loan agreement. In January 2008, we entered into an Amended Guaranty agreement with Centennial's lenders, under which the TEPPCO Guarantors are required, on a joint and several basis, to pay 50% of any past-due amount under Centennial's master shelf loan agreement not paid by Centennial. The Amended Guaranty also has a credit maintenance requirement whereby we may be required to provide additional credit support in the form of a letter of credit or pay certain fees if either of our credit ratings from Standard & Poor's Ratings Group and Moody's Investors Service, Inc. falls below investment grade levels as specified in the Amended Guaranty. If Centennial defaults on its debt obligations, the estimated maximum potential amount of future payments for the TEPPCO Guarantors and Marathon is $66.2 million each at September 30, 2008. At September 30, 2008, we have a liability of $9.1 million, which is based upon the expected present value of amounts we would have to pay under the guarantee.

TE Products, Marathon and Centennial have also 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, at September 30, 2008, TE Products has a liability of $3.9 million, which is based upon the expected present value of amounts we would have to pay under the guarantee. If a catastrophic event were to occur and we were required to contribute cash to Centennial, such contributions might be covered by our insurance (net of deductible), depending upon the nature of the catastrophic event.

One of our subsidiaries, TCO, has entered into master equipment lease agreements with finance companies for the use of various pieces of equipment. Lease expense related to this equipment is approximately $5.2 million per year. 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. We do not believe that any performance under the guarantee would have a material effect on our financial condition, results of operations or cash flows.

Motiva Project

In December 2006, we signed an agreement with Motiva Enterprises, LLC ("Motiva") for us to construct and operate a new refined products storage facility to support the expansion of Motiva's refinery in Port Arthur, Texas. Under the terms of the agreement, we are constructing a 5.4 million barrel refined products storage facility for gasoline and distillates. The agreement also provides for a 15-year throughput and dedication of volume, which will commence upon completion of the refinery expansion. The project includes the construction of 20 storage tanks, five 5.4-mile product pipelines connecting the storage facility to Motiva's refinery, 21,000 horsepower of pumping capacity, and distribution pipeline connections to the Colonial, Explorer and Magtex pipelines. The storage and pipeline project is expected to be completed by January 1, 2010. As a part of a separate but complementary initiative, we are constructing an 11-mile, 20-inch pipeline to connect the new storage facility in Port Arthur to our refined products terminal in Beaumont, Texas, which is the primary origination facility for our mainline system. These projects will facilitate connections to additional markets through the Colonial, Explorer and Magtex pipeline systems and provide the Motiva refinery with access to our pipeline system. The total cost of the project is expected to be approximately $310.0 million, which includes $20.0 million for the 11-mile, 20-inch pipeline, $30.0 million of capitalized interest and $17.0 million of mutually agreed upon scope changes requested by Motiva. Through September 30, 2008, we have spent approximately $89.8 million on this construction project. Under the terms of the agreement, if Motiva cancels the agreement prior to the commencement date of the project, Motiva will reimburse us the actual reasonable expenses we have incurred after the effective date of the agreement, including both internal and external costs that would be capitalized as a part of the project, plus a ten percent cancellation fee.

Texas Offshore Port System

We, through a subsidiary, own a one-third interest in the Texas Offshore Port System joint venture. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such expenditures occurring in 2009 and 2010. We have guaranteed up to approximately $700.0 million of the capital expenditure obligations of our subsidiary in the joint venture. See Note 8 for further information.

NOTE 17. SUPPLEMENTAL CASH FLOW INFORMATION

The following table provides information regarding (i) the net effect of changes in our operating assets and liabilities, (ii) non-cash investing and financing activities and (iii) cash payments for interest for the nine months ended September 30, 2008 and 2007:

	For the Nine Months Ended September 30, 2008	2007
Decrease (increase) in:		
Accounts receivable, trade	$ (333,633)	$ (296,058)
Accounts receivable, related parties	222	(5,556)
Inventories	(86,545)	(61,729)
Other current assets	(15,067)	(5,240)
Other	(25,758)	(16,529)
Increase (decrease) in:		
Accounts payable and accrued expenses	411,621	331,312
Accounts payable, related parties	6,169	(672)
Other	19,557	1,022
Net effect of changes in operating accounts	$ (23,434)	$ (53,450)
Non-cash investing activities:		
Payable to Enterprise Gas Processing, LLC for spending for Phase V expansion of Jonah Gas Gathering Company (see Note 8)	$ 1,323	$ 12,968
Payable to Texas Offshore Port System (see Note 8)	$ 2,347	$ --
Non-cash financing activities:		
Issuance of Units in Cenac acquisition (see Note 9)	$ 186,558	$ --
Supplemental disclosure of cash flows:		
Cash paid for interest (net of amounts capitalized)	$ 81,889	$ 73,086

We determine net cash flows provided by operating activities using the indirect method, which adjusts net income for items that did not affect cash. Under GAAP, we use the accrual basis of accounting to determine net income. This basis requires that we record revenue when earned and expenses when incurred. Earned revenues may include credit sales that have not been collected in cash and expenses incurred that may not have been paid in cash.

The extent to which changes in operating accounts influence net cash flows provided by operating activities generally depends on the following:

- § The timing of cash receipts from revenue transactions and cash payments for expense transactions near the end of each reporting period. For example, if significant cash receipts are posted on the last day of the current reporting period, but subsequent payments on expense invoices are made on the first day of the next reporting period, net cash flows provided by operating activities will reflect an increase in the current reporting period that will be reduced as payments are made in the next period.

- § If commodity or other prices increase between reporting periods, changes in accounts receivable and accounts payable and accrued expenses may appear larger than in previous periods; however, overall levels of receivables and payables may still reflect normal ranges.

- § Additions to inventory for forward sales transactions or other reasons or increased expenditures for prepaid items would be reflected as a use of cash and reduce overall cash provided by operating activities in a given reporting period. As these assets are charged to expense in subsequent periods, the expense amount is reflected as a positive change in operating accounts; however, there is no impact on operating cash flows.

In addition to the adjustments noted above, non-cash charges in the income statement are added back to net income and noncash credits are deducted to compute net cash flows provided by operating activities. Examples of noncash charges include depreciation and amortization.

NOTE 18. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

TE Products, TCTM, TEPPCO Midstream and Val Verde have issued full, unconditional, and joint and several guarantees of our senior notes, our Junior Subordinated Notes (collectively “the Guaranteed Debt”), our Revolving Credit Facility, and prior to its termination, our Term Credit Facility. TE Products, TCTM, TEPPCO Midstream and Val Verde are collectively referred to as the “Guarantor Subsidiaries.”

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

	September 30, 2008				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 117,143	$ 98,174	$ 1,869,562	$ (114,079)	$ 1,970,800
Property, plant and equipment – net	--	1,248,928	1,123,766	--	2,372,694
Equity investments	1,419,218	1,355,230	196,193	(1,779,264)	1,191,377
Intercompany notes receivable	2,485,250	--	--	(2,485,250)	--
Intangible assets	--	121,886	92,484	--	214,370
Goodwill	--	--	106,404	--	106,404
Other assets	14,673	31,918	83,389	--	129,980
Total assets	$ 4,036,284	$ 2,856,136	$ 3,471,798	$ (4,378,593)	$ 5,985,625
Liabilities and partners' capital					
Current liabilities	$ 50,492	$ 110,243	$ 1,931,935	$ (114,079)	$ 1,978,591
Long-term debt	2,338,745	--	--	--	2,338,745
Intercompany notes payable	--	1,596,500	888,750	(2,485,250)	--
Other long-term liabilities	8,896	18,190	3,052	--	30,138
Total partners' capital	1,638,151	1,131,203	648,061	(1,779,264)	1,638,151
Total liabilities and partners' capital	$ 4,036,284	$ 2,856,136	$ 3,471,798	$ (4,378,593)	$ 5,985,625

	December 31, 2007				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 32,302	$ 77,083	$ 1,499,653	$ (93,049)	$ 1,515,989
Property, plant and equipment – net	--	1,142,630	651,004	--	1,793,634
Equity investments	1,286,021	1,347,313	188,669	(1,675,008)	1,146,995
Intercompany notes receivable	1,511,168	--	--	(1,511,168)	--
Intangible assets	--	136,050	28,631	--	164,681
Goodwill	--	--	15,506	--	15,506
Other assets	8,580	34,839	69,895	(62)	113,252
Total assets	$ 2,838,071	$ 2,737,915	$ 2,453,358	$ (3,279,287)	$ 4,750,057
Liabilities and partners' capital					
Current liabilities	$ 61,926	$ 493,184	$ 1,485,164	$ (93,049)	$ 1,947,225
Long-term debt	1,511,083	--	--	--	1,511,083
Intercompany notes payable	--	1,006,801	504,367	(1,511,168)	--
Other long term liabilities	435	24,466	2,283	(62)	27,122
Total partners' capital	1,264,627	1,213,464	461,544	(1,675,008)	1,264,627
Total liabilities and partners' capital	$ 2,838,071	$ 2,737,915	$ 2,453,358	$ (3,279,287)	$ 4,750,057

	For the Three Months Ended September 30, 2008				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ --	$ 97,014	$ 4,108,765	$ (35)	$ 4,205,744
Costs and expenses	--	76,850	4,069,199	(164)	4,145,885
Gains on sales of assets	--	--	(1)	--	(1)
Operating income	--	20,164	39,567	129	59,860
Interest expense – net	--	(18,820)	(15,481)	--	(34,301)
Equity earnings	47,031	44,318	2,748	(71,964)	22,133
Other income – net	--	211	184	--	395
Income before provision for income taxes	47,031	45,873	27,018	(71,835)	48,087
Provision for income taxes	--	399	657	--	1,056
Net income	$ 47,031	$ 45,474	$ 26,361	$ (71,835)	$ 47,031

	For the Three Months Ended September 30, 2007				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ --	$ 92,339	$ 2,488,370	$ (52)	$ 2,580,657
Costs and expenses	--	69,254	2,456,744	(58)	2,525,940
Gains on sales of assets	--	(2)	--	--	(2)
Operating income	--	23,087	31,626	6	54,719
Interest expense – net	--	(20,131)	(6,770)	--	(26,901)
Gain on sale of ownership interest in MB Storage	--	(20)	--	--	(20)
Equity earnings	47,631	44,180	1,073	(73,825)	19,059
Other income – net	--	615	145	--	760
Income before provision for income taxes	47,631	47,731	26,074	(73,819)	47,617
Provision for income taxes	--	100	(114)	--	(14)
Net income	$ 47,631	$ 47,631	$ 26,188	$ (73,819)	$ 47,631

	For the Nine Months Ended September 30, 2008				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ --	$ 288,148	$ 10,906,681	$ (134)	$ 11,194,695
Costs and expenses	--	215,075	10,781,191	(4,225)	10,992,041
Gains on sales of assets	--	--	(1)	--	(1)
Operating income	--	73,073	125,491	4,091	202,655
Interest expense – net	--	(62,996)	(42,910)	--	(105,906)
Equity earnings	158,852	142,315	9,925	(247,880)	63,212
Other income – net	--	793	992	--	1,785
Income before provision for income taxes	158,852	153,185	93,498	(243,789)	161,746
Provision for income taxes	--	888	2,006	--	2,894
Net income	$ 158,852	$ 152,297	$ 91,492	$ (243,789)	$ 158,852

	For the Nine Months Ended September 30, 2007				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ --	$ 278,944	$ 6,330,073	$ (495)	$ 6,608,522
Costs and expenses	--	202,876	6,239,366	(3,949)	6,438,293
Gains on sales of assets	--	(18,653)	--	--	(18,653)
Operating income	--	94,721	90,707	3,454	188,882
Interest expense – net	--	(51,435)	(20,462)	--	(71,897)
Gain on sale of ownership interest in MB Storage	--	59,628	--	--	59,628
Equity earnings	233,582	128,339	4,310	(311,375)	54,856
Other income – net	--	1,934	392	--	2,326
Income before provision for income taxes	233,582	233,187	74,947	(307,921)	233,795
Provision for income taxes	--	(395)	608	--	213
Net income	$ 233,582	$ 233,582	$ 74,339	$ (307,921)	$ 233,582

	For the Nine Months Ended September 30, 2008				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating activities:					
Net cash from operating activities	$ (805,635)	$ 297,738	$ 142,275	$ 660,491	$ 294,869
Cash flows from investing activities					
Cash used for business combinations	--	--	(351,866)	--	(351,866)
Investment in Jonah	--	(94,875)	--	--	(94,875)
Capital expenditures	--	(143,690)	(71,472)	--	(215,162)
Other, net	--	(317)	(11,538)	--	(11,855)
Net used in investing activities	--	(238,882)	(434,876)	--	(673,758)
Cash flows from financing activities					
Proceeds from term credit facility	1,000,000	--	--	--	1,000,000
Repayments on term credit facility	(1,000,000)	--	--	--	(1,000,000)
Proceeds on revolving credit facility	1,852,567	--	--	--	1,852,567
Repayments on revolving credit facility	(2,017,850)	--	--	--	(2,017,850)
Repayment of debt assumed in Cenac acquisition	--	--	(63,157)	--	(63,157)
Redemption of 7.51% TE Products Senior Notes	--	(181,571)	--	--	(181,571)
Repayment of 6.45% TE Products Senior Notes	--	(180,000)	--	--	(180,000)
Issuance of Limited Partner Units, net	271,313	--	--	--	271,313
Issuance of senior notes	996,349	--	--	--	996,349
Debt issuance costs	(9,857)	--	--	--	(9,857)
Settlement of treasury lock agreements	(52,098)	--	--	--	(52,098)
Intercompany debt activities	--	539,420	436,838	(976,258)	--
Distributions	(236,775)	(236,775)	(81,074)	317,849	(236,775)
Cash flows from financing activities	803,649	(58,926)	292,607	(658,409)	378,921
Net change in cash and cash equivalents	(1,986)	(70)	6	2,082	32
Cash and cash equivalents, January 1	8,147	70	22	(8,216)	23
Cash and cash equivalents, September 30	$ 6,161	$ --	$ 28	$ (6,134)	$ 55

	For the Nine Months Ended September 30, 2007				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating activities:					
Net cash from operating activities	$ 39,830	$ 146,245	$ 131,683	$ (98,572)	$ 219,186
Cash flows from investing activities					
Proceeds from sales of assets	--	26,541	1,230	--	27,771
Proceeds from sale of ownership interest	--	137,326	--	--	137,326
Purchase of assets	--	(6,016)	(6,717)	--	(12,733)
Investment in Centennial	--	(11,081)	--	--	(11,081)
Investment in Jonah	--	(127,775)	--	--	(127,775)
Capital expenditures	--	(108,133)	(56,028)	--	(164,161)
Other, net	--	(16,932)	(12,182)	(2,876)	(31,990)
Net used in investing activities	--	(106,070)	(73,697)	(2,876)	(182,643)
Cash flows from financing activities					
Proceeds on revolving credit facility	805,250	--	--	--	805,250
Repayments on revolving credit facility	(918,250)	--	--	--	(918,250)
Issuance of Limited Partner Units, net	53	--	--	--	53
Issuance of Junior Subordinated Notes	299,517	--	--	--	299,517
Debt issuance costs	(3,750)	--	--	--	(3,750)
Intercompany debt activities	--	180,910	5,607	(186,517)	--
Distributions	(219,613)	(219,613)	(63,637)	283,250	(219,613)
Other, net	1,390	(1,236)	2	52	208
Cash flows from financing activities	(35,403)	(39,939)	(58,028)	96,785	(36,585)
Net change in cash and cash equivalents	4,427	236	(42)	(4,663)	(42)
Cash and cash equivalents, January 1	10,975	--	70	(10,975)	70
Cash and cash equivalents, September 30	$ 15,402	$ 236	$ 28	$ (15,638)	$ 28

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

For the three months and nine months ended September 30, 2008 and 2007

The following information should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes included in this report. The following information and such unaudited condensed consolidated financial statements should be read in conjunction with the financial statements and related notes, together with our discussion and analysis of financial position and results of operations included in our Annual Report on Form 10-K for the year ended December 31, 2007. Our discussion and analysis includes the following:

- Key References Used in this Quarterly Report.
- Cautionary Note Regarding Forward-Looking Statements.
- Overview of Critical Accounting Policies and Estimates.
- Overview of Business.
- Recent Developments – Discusses recent developments during the quarter ended September 30, 2008.
- Results of Operations – Discusses material period-to-period variances in the statements of consolidated income.
- Financial Condition and Liquidity – Analyzes cash flows and financial position.
- Other Considerations – Addresses available sources of liquidity, and certain trends, future plans and contingencies.
- Recent Accounting Pronouncements.

As generally used in the energy industry and in this discussion, the identified terms have the following meanings:

/d	= per day
BBtus	= billion British Thermal units
Bcf	= billion cubic feet
MMBtus	= million British Thermal units
MMcf	= million cubic feet
Mcf	= thousand cubic feet
MMBbls	= million barrels

Our financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP").

Key References Used in this Quarterly Report

Unless the context requires otherwise, references to "*we*," "*us*," "*our*," the "*Partnership*" or "*TEPPCO*" are intended to mean the business and operations of TEPPCO Partners, L.P. and its consolidated subsidiaries.

References to "*TE Products*," "*TCTM*," "*TEPPCO Midstream*" and "*TEPPCO Marine Services*" mean TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and TEPPCO Marine Services, LLC, our subsidiaries.

References to "*General Partner*" mean Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and owned by Enterprise GP Holdings L.P., a publicly traded partnership, controlled indirectly by EPCO, Inc.

References to "*Enterprise GP Holdings*" mean Enterprise GP Holdings L.P., a publicly traded partnership that owns our General Partner and Enterprise Products GP, LLC, the general partner of Enterprise Products Partners L.P.

References to “*Enterprise Products Partners*” mean Enterprise Products Partners L.P., and its consolidated subsidiaries, a publicly traded Delaware limited partnership, which is an affiliate of ours.

References to “*EPCO*” mean EPCO, Inc., a privately-held company that is affiliated with our General Partner. Dan L. Duncan is the Group Co-Chairman and controlling shareholder of EPCO.

Cautionary Note Regarding Forward-Looking Statements

The matters discussed in this Quarterly Report on Form 10-Q (this “Report”) include “forward-looking statements.” 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, anticipated outcome of various legal and regulatory proceedings, plans, references to future success or events, anticipated market or industry developments, 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 or energy transportation companies, changes in laws or regulations and other factors, many of which are beyond our control. For example, the demand for refined products is dependent upon the price, prevailing economic conditions and demographic changes in the markets served, trucking and railroad freight, agricultural usage and military usage; the demand for propane is sensitive to the weather and prevailing economic conditions; the demand for petrochemicals is dependent upon prices for products produced from petrochemicals; the demand for crude oil and petroleum products is dependent upon the price of crude oil and the products produced from the refining of crude oil; the demand for natural gas is dependent upon the price of natural gas and the locations in which natural gas is drilled; and the demand for marine transportation services is dependent upon the demand for products and prevailing economic conditions. Further, the success of our new marine services business is dependent upon, among other things, our ability to effectively assimilate and provide for the operation of that business, maintain key personnel and customer relationships and obtain favorable contract renewals. 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 and the cost and ability of complying with government regulations of the marine transportation industry. 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 additional cautionary discussion of risks and uncertainties under the captions “Risk Factors,” “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and elsewhere in this Report and in our Annual Report on Form 10-K for the year ended December 31, 2007.

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 us or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this Report and in our future periodic reports filed with the U.S. Securities and Exchange Commission (“SEC”). In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Report may not occur.

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, 2007. 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; reserves for environmental matters; depreciation methods and estimated useful lives of property, plant and equipment; and goodwill and 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, results of operations and cash flows.

Overview of Business

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 operate and report in four business segments:

§ Our Downstream Segment, which is engaged in the pipeline transportation, marketing and storage of refined products, liquefied petroleum gases ("LPGs") and petrochemicals;
§ Our Upstream Segment, which is engaged in the gathering, pipeline transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals;
§ Our Midstream Segment, which is engaged in the gathering of natural gas, pipeline transportation of natural gas liquids ("NGLs") and fractionation of NGLs; and
§ Our Marine Services Segment, which is engaged in the marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges.

Please refer to Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Overview of Business in our Annual Report on Form 10-K for the year ended December 31, 2007 for an overview of how revenues are earned in each segment and other factors affecting the results and financial position of our businesses.

As part of our growth strategy, we engage from time to time in discussions with potential sellers and strategic partners regarding the possible purchase of assets, pursuit of joint ventures or other expansion opportunities that complement our principal lines of business. These potential expansion opportunities consist of both smaller transactions, as well as larger transactions that could have a material impact on our capital structure and operating results. We cannot predict the likelihood of completing, or the timing of, any such transactions.

Recent Developments

Texas Offshore Port System Joint Venture

In August 2008, we, together with Enterprise Products Partners and Oiltanking Holding Americas, Inc. ("Oiltanking") announced the formation of a joint venture to design, construct, operate and own a new Texas offshore crude oil port and pipeline system to facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of total crude oil storage capacity, and (iii) an 85-mile pipeline system that will have the capacity to deliver up to 1.8 million barrels per day of crude oil, that will extend from the offshore port to a Texas City, Texas storage facility. TOPS is expected to begin service as early as the fourth quarter of 2010. The joint venture's second and complementary project, referred to as the Port Arthur Crude Oil Express ("PACE") will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and

1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. PACE is expected to begin service as early as the third quarter of 2010. Development of the TOPS and PACE projects is supported by long-term contracts with affiliates of Motiva Enterprises, LLC and Exxon Mobil Corporation, which have committed a combined 725,000 barrels per day of crude oil to the projects.

We, Enterprise Products Partners and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. A subsidiary of Enterprise Products Partners acts as construction manager and will act as operator. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures occurring in 2009 and 2010. We and an affiliate of Enterprise Products Partners have each guaranteed up to approximately $700.0 million of the capital contribution obligations of our respective subsidiary partners in the joint venture. At September 30, 2008, we have a payable of $2.3 million for our investment in the joint venture, which will be paid during the fourth quarter of 2008.

The joint venture is an integral part of our strategic plan for growing the Partnership. Demand for the project is being driven by planned and expected refinery expansions along the U.S. Gulf Coast, expected increased shipping traffic and operating limitations of ship channels. Further, the joint venture complements our 5.4 million barrel refined products storage facility currently under construction in Port Arthur to support the expansion of Motiva Enterprises, LLC's nearby refinery, which is expected to double its existing capacity in 2010.

Equity Offering and Registration Statement

In September 2008, we filed a universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities and removed from registration securities remaining under our previous universal shelf registration statement.

On September 9, 2008, we issued and sold in an underwritten public offering 9.2 million Units at a price to the public of $29.00 per Unit, including 1.2 million Units sold upon exercise of the underwriters' over-allotment option granted in connection with the offering. The proceeds from the offering, net of underwriting discount and offering expenses, totaled approximately $257.0 million. Concurrently with this offering, we sold 241,380 unregistered Units at the public offering price of $29.00 to TEPPCO Unit L.P. ("TEPPCO Unit"), an affiliate of EPCO in which certain EPCO employees who perform services for us, including the executive officers named in the Executive Compensation section of our most recent Annual Report on Form 10-K, were issued Class B limited partner interests to incentivize them to enhance the long-term value of our Units. The net proceeds from the offering and the unregistered issuance to TEPPCO Unit were used to reduce indebtedness under our revolving credit facility. For additional information regarding TEPPCO Unit and the equity-based compensatory awards issued therein, please see Note 3 in the Notes to Unaudited Condensed Consolidated Financial Statements.

Expansion of Inland Waterway Distribution Network

In August 2008, we commenced operations at our new 500,000 barrel Boligee refined products terminal in Greene County, Alabama. Located along the Tennessee Tombigbee waterway, the facility provides gasoline, diesel and ethanol storage capabilities and provides for direct access to most U.S. Gulf Coast refining centers through an interconnect with the Colonial pipeline system. Additionally, the intermodal terminal offers truck and marine transportation options and future rail capabilities. The facility will also serve as an origination point for refined products delivered to our 130,000 barrel terminal in Aberdeen, Mississippi.

Acquisition of Lubrication and Other Fuel Oil Assets

On August 1, 2008, we purchased lubrication and other fuel oil assets, located in Wyoming, from Quality Petroleum, Inc. ("Quality Petroleum") for approximately $7.5 million. The assets, included in our Upstream Segment, consist of operating inventory, buildings, land and various equipment and the assignment of certain distributor agreements. We funded the purchase through borrowings under our revolving credit facility. For additional information regarding this acquisition, see Note 9 in the Notes to Unaudited Condensed Consolidated Financial Statements.

Results of Operations

The following table summarizes financial information by business segment for the three months and nine months ended September 30, 2008 and 2007 (in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Operating revenues:				
Downstream Segment	$ 97,052	$ 84,528	$ 271,187	$ 262,626
Upstream Segment	4,032,384	2,465,031	10,713,042	6,255,434
Midstream Segment	30,325	31,150	91,010	90,957
Marine Services Segment	46,018	--	119,590	--
Intersegment eliminations	(35)	(52)	(134)	(495)
Total operating revenues	4,205,744	2,580,657	11,194,695	6,608,522
Operating income:				
Downstream Segment	18,671	26,646	70,654	101,533
Upstream Segment	26,903	20,602	81,871	63,660
Midstream Segment	5,803	7,465	22,467	20,235
Marine Services Segment	8,354	--	23,572	--
Intersegment eliminations	129	6	4,091	3,454
Total operating income	59,860	54,719	202,655	188,882
Equity earnings (losses):				
Downstream Segment	(2,349)	(3,064)	(10,066)	(8,430)
Upstream Segment	2,748	1,073	9,925	4,310
Midstream Segment	21,863	21,056	67,444	62,430
Intersegment eliminations	(129)	(6)	(4,091)	(3,454)
Total equity earnings	22,133	19,059	63,212	54,856
Earnings before interest:(1)				
Downstream Segment	16,500	24,096	61,293	154,454
Upstream Segment	29,766	21,719	92,539	68,114
Midstream Segment	27,763	28,703	90,237	83,124
Marine Services Segment	8,359	--	23,583	--
Interest expense	(38,593)	(28,911)	(120,083)	(80,710)
Interest capitalized	4,292	2,010	14,177	8,813
Income before provision for income taxes	48,087	47,617	161,746	233,795
Provision for income taxes	1,056	(14)	2,894	213
Net income	$ 47,031	$ 47,631	$ 158,852	$ 233,582

(1) See Note 13 in the Notes to Unaudited Condensed Consolidated Financial Statements for a reconciliation of earnings before interest to net income.

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

Downstream Segment

The following table provides financial information for the Downstream Segment for the three months and nine months ended September 30, 2008 and 2007 (in thousands):

	For the Three Months Ended September 30,		Increase	For the Nine Months Ended September 30,		Increase
	2008	**2007**	**(Decrease)**	**2008**	**2007**	**(Decrease)**
Operating revenues:						
Sales of petroleum products	$ 12,964	$ 5,600	$ 7,364	$ 21,271	$ 24,379	$ (3,108)
Transportation – Refined products	42,203	48,123	(5,920)	123,602	126,976	(3,374)
Transportation – LPGs	16,335	16,735	(400)	68,589	69,535	(946)
Other	25,550	14,070	11,480	57,725	41,736	15,989
Total operating revenues	97,052	84,528	12,524	271,187	262,626	8,561
Costs and expenses:						
Purchases of petroleum products	12,873	5,465	7,408	21,089	24,170	(3,081)
Operating expense	38,230	25,165	13,065	95,558	71,459	24,099
Operating fuel and power	8,830	9,438	(608)	29,806	29,255	551
General and administrative	4,212	3,953	259	12,375	12,272	103
Depreciation and amortization	10,736	11,282	(546)	31,474	34,142	(2,668)
Taxes – other than income taxes	3,500	2,581	919	10,231	8,448	1,783
Gains on sales of assets	--	(2)	2	--	(18,653)	18,653
Total costs and expenses	78,381	57,882	20,499	200,533	161,093	39,440
Operating income	18,671	26,646	(7,975)	70,654	101,533	(30,879)
Gain on sale of ownership interest In Mont Belvieu Storage Partners, L.P. (“MB Storage”)	--	(20)	20	--	59,628	(59,628)
Equity losses	(2,349)	(3,064)	715	(10,066)	(8,430)	(1,636)
Interest income	170	231	(61)	498	662	(164)
Other income – net	8	303	(295)	207	1,061	(854)
Earnings before interest	$ 16,500	$ 24,096	$ (7,596)	$ 61,293	$ 154,454	$ (93,161)

The following table presents volumes delivered in barrels and average tariff per barrel for the three months and nine months ended September 30, 2008 and 2007 (in thousands, except tariff information):

	For the Three Months Ended September 30,		Percentage Increase	For the Nine Months Ended September 30,		Percentage Increase
	2008	**2007**	**(Decrease)**	**2008**	**2007**	**(Decrease)**
Volumes Delivered:						
Refined products (1)	41,162	48,947	(16%)	121,574	129,623	(6%)
LPGs	6,725	7,080	(5%)	26,263	29,567	(11%)
Total	47,887	56,027	(15%)	147,837	159,190	(7%)
Average Tariff per Barrel:						
Refined products	$ 1.03	$ 0.98	5%	$ 1.02	$ 0.98	4%
LPGs	2.43	2.36	3%	2.61	2.27	15%
Average system tariff per barrel	1.22	1.16	5%	1.30	1.23	6%

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(1) Includes 7,355 and 10,001 barrels and 20,600 and 26,660 barrels delivered via the Centennial Pipeline during the three months and nine months ended September 30, 2008 and 2007, respectively.

We generally realize higher revenues in the Downstream Segment during the first and fourth quarters of each year since LPGs volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating, and due to the demand for normal butane, which is used for the blending of gasoline. 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, although recent high gasoline prices have moderated this trend somewhat. 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.

Three Months Ended September 30, 2008 Compared with Three Months Ended September 30, 2007

We conduct distribution and marketing operations and terminaling services for our throughput partner at our Aberdeen, Mississippi and Boligee, Alabama terminals. We also purchase petroleum products from our throughput partner that we in turn sell through spot and contract sales at our Aberdeen and Boligee truck racks to independent wholesalers and retailers of refined products. Sales and purchases related to these petroleum products marketing activities increased $7.4 million each for the three months ended September 30, 2008, compared with the three months ended September 30, 2007. The increases in purchases and sales were primarily a result of the start-up at the Boligee terminal in August 2008 and the completion of unplanned maintenance on storage tanks at the Aberdeen terminal during the quarter, which had been ongoing since the first quarter of 2008.

Revenues from refined products transportation decreased $5.9 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, primarily due a 16% decrease in refined products volumes delivered, partially offset by a 5% increase in the average tariff per barrel. Volume decreases were primarily due to product supply disruptions resulting from downtime at several refineries along the upper Texas Gulf Coast following Hurricanes Gustav and Ike, reduced demand for transportation fuels due to high prices and higher than usual demand from the Gulf Coast in the 2007 period due to Midwest refinery downtime. The refined products average tariff per barrel increased 5% primarily due to tariff increases that went into effect on April 1 and July 1, 2008.

In August and September 2008, the U.S. Gulf Coast was impacted by Hurricanes Gustav and Ike, respectively. These hurricanes resulted in a reduction in availability of product for shipment due to refinery shutdowns in preparation for the storms and reduced pipeline capacity due to electric power outages in the wake of the storms. While it is difficult to accurately measure the lost revenues as a result of the hurricanes, we estimate that the third quarter 2008 revenues of our Downstream Segment were reduced by approximately $3.0 million.

Revenues from LPGs transportation decreased $0.4 million for the three months ended September 30, 2008, compared to the three months ended September 30, 2007, primarily due to a 5% decrease in transportation volumes delivered, partially offset by a 3% increase in the average tariff per barrel. Isobutane transportation volumes were lower in the 2008 period due to reduced demand resulting from a refinery turnaround and unplanned refinery disruptions in the Midwest. Propane transportation volumes were lower in the 2008 period compared to the prior year period due to the negative demand impact of high prices. The LPGs average rate per barrel increased 3% due to a July 2008 tariff increase partially offset by an increased proportion of shorter haul deliveries to the Midwest market areas as compared to the Northeast market areas.

Other operating revenues increased $11.5 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, primarily due to an $11.1 million increase in product inventory sales in connection with an exchange contract modification and a $0.4 million increase in upsystem product exchange revenue. Periodic inventory sales and purchases occur to balance product grades within the pipeline system as part of routine pipeline operations. These increased revenues from product inventory sales were partially offset by a lower of cost or market adjustment to reduce the value of remaining product inventory to market values at September 30, 2008, as discussed below.

Costs and expenses increased $20.5 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007. Purchases of petroleum products, discussed above, increased $7.4 million, compared with the prior year period. Operating expenses increased $13.1 million primarily due to a $7.7 million lower of cost or market ("LCM") adjustment on inventory (see Note 6 in the Notes to the Unaudited Condensed Consolidated Financial Statements), a $6.5 million increase in pipeline operating and maintenance costs primarily related to periodic tank maintenance requirements pursuant to recommended industry practices outlined in American Petroleum Institute ("API") 653 in the 2008 period and other repairs and maintenance on various sections of pipeline, a $0.4 million increase in expenses related to pipeline tariffs for terminal deliveries and a $0.3 million decrease in product measurement gains. These increases in operating expenses were partially offset by a $0.8 million decrease in transportation expense related to movements on Centennial and a $0.8 million decrease in pipeline rental expense on a third party pipeline. Operating fuel and power decreased $0.6 million primarily due to lower mainline transportation volumes. General and administrative expenses increased $0.3 million primarily due to higher labor and benefits expense and higher legal expenses. Depreciation and amortization expense decreased $0.5 million primarily due to asset retirements in 2007, partially offset by assets placed into service in the 2008 period. Taxes – other than income taxes increased $0.9 million primarily due to true-ups of property tax accruals and a higher asset base.

Net losses from equity investments decreased for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, as shown below (in thousands):

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	Increase (Decrease)
Centennial	$ (2,369)	$ (2,800)	$ 431
MB Storage	--	(279)	279
Other	20	15	5
Total equity losses	$ (2,349)	$ (3,064)	$ 715

Equity losses in Centennial decreased $0.4 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, primarily due to lower operating expenses and lower amortization expense related to our excess investment in Centennial as a result of lower volumes, partially offset by lower transportation revenues, resulting from reduced demand for transportation of refined products from the U.S. Gulf Coast to the mid-continent and the effects of Hurricane Ike which resulted in a combination of system downtime and reduced availability of supply due to delayed refinery startups after the storm. Volumes on Centennial averaged 105,700 barrels per day during the three months ended September 30, 2008, compared with 180,800 barrels per day during the three months ended September 30, 2007.

Due to the sale of MB Storage on March 1, 2007 to Louis Dreyfus Energy Services L.P. ("Louis Dreyfus") (see Note 9 in the Notes to Unaudited Condensed Consolidated Financial Statements), there were no equity losses in MB Storage for the three months ended September 30, 2008, compared with $0.3 million in losses for the three months ended September 30, 2007. During the third quarter of 2007, we recorded $0.3 million of expense relating to post closing adjustments associated with the March 1, 2007 sale of TE Products' interest in MB Storage.

Other income – net decreased $0.3 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, due to the receipt of various right-of-way payments in 2007.

Nine Months Ended September 30, 2008 Compared with Nine Months Ended September 30, 2007

Sales and purchases related to petroleum products marketing activities each decreased $3.1 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007. The decreases in purchases and sales were primarily a result of unplanned maintenance on storage tanks at the Aberdeen terminal during the nine months ended September 30, 2008, partially offset by the start-up of the Boligee terminal in August 2008.

Revenues from refined products transportation decreased $3.4 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, primarily due to a 6% decrease in refined products delivered, partially offset by a 4% increase in the average tariff per barrel. The refined products volume decreases were primarily due to lower distillate volumes resulting from product supply disruptions from downtime at several refineries along the upper Texas Gulf Coast following Hurricanes Gustav and Ike, as discussed above, and higher than usual demand from the Gulf Coast in the 2007 period due to Midwest refinery turnarounds. These decreases were partially offset by increased jet fuel deliveries and higher tariffs from rate increases that went into effect in April and July 2008. Additionally, revenues were increased by the recognition of $2.1 million of deferred revenue in the second quarter of 2008 related to time limit expirations under two transportation agreements without the customers recovering the deferred revenue.

Revenues from LPG transportation decreased $0.9 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, primarily due to lower isobutane deliveries in the Midwest and decreased propane deliveries in the Northeast market areas as a result of high product prices and warmer weather during the first quarter of 2008. LPG transportation volumes in the 2007 period include approximately 2.2 million barrels related to short-haul propane movements on a pipeline that was sold on March 1, 2007 to Louis Dreyfus. The LPGs average rate per barrel increased 15% from the prior year period primarily as a result of decreased short-haul deliveries due to the pipeline sale and a July 2008 tariff increase.

Other operating revenues increased $16.0 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, primarily due to an $11.1 million increase in product inventory sales in connection with an exchange contract modification, a $2.3 million increase in refined products excess inventory revenue, a $1.3 million increase in refined products terminaling revenue and a $0.7 million increase in upsystem product exchange revenue.

Costs and expenses increased $39.4 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007. Purchases of petroleum products, discussed above, decreased $3.1 million, compared with the prior year period. Operating expenses increased $24.1 million primarily due to a $16.0 million increase in pipeline operating and maintenance costs principally related to periodic tank maintenance requirements in the 2008 period and other repairs and maintenance expenses on various pipeline segments, a $7.7 million LCM adjustment on inventory (see Note 6 in the Notes to Unaudited Condensed Consolidated Financial Statements), a $2.4 million write-off of project costs, a $1.1 million increase in environmental assessments and remediation costs and a $0.6 million increase in labor and benefits expense. These increases in operating expenses were partially offset by a $1.1 million decrease in insurance premiums, a $1.0 million decrease in transportation expense related to movements on Centennial and a $0.7 million decrease in pipeline inspection and repair costs associated with our integrity management program. Operating fuel and power increased $0.6 million primarily due to higher power rates as a result of the increased cost of fuel and true-ups of power accruals. General and administrative expenses increased $0.1 million primarily due to higher labor and benefits expense partially offset by lower consulting and contract services. Depreciation and amortization expense decreased $2.7 million primarily due to asset retirements in 2007, partially offset by assets placed into service in the 2008 period. Taxes – other than income taxes increased $1.8 million primarily due to true-ups of property tax accruals and a higher asset base. During the nine months ended September 30, 2007, we recognized a net gain of $18.7 million from the sales of various assets in the Downstream Segment to Enterprise Products Partners and Louis Dreyfus (see Note 9 in the Notes to Unaudited Condensed Consolidated Financial Statements).

Net losses from equity investments increased for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, as shown below (in thousands):

	For the Nine Months Ended September 30,		Increase
	2008	2007	(Decrease)
Centennial	$ (10,122)	$ (9,549)	$ (573)
MB Storage	--	1,089	(1,089)
Other	56	30	26
Total equity losses	$ (10,066)	$ (8,430)	$ (1,636)

Equity losses in Centennial increased $0.6 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, primarily due to lower transportation volumes primarily from the effects of Hurricane Ike, as discussed above, partially offset by lower operating expenses. Volumes on Centennial averaged 115,000 barrels per day during the nine months ended September 30, 2008, compared with 146,000 barrels per day during the nine months ended September 30, 2007.

Due to the sale of MB Storage on March 1, 2007 to Louis Dreyfus (see Note 9 in the Notes to Unaudited Condensed Consolidated Financial Statements), there were no equity earnings in MB Storage for the nine months ended September 30, 2008, compared with $1.1 million in earnings for the nine months ended September 30, 2007. On March 1, 2007, TE Products sold its 49.5% ownership interest in MB Storage and its 50% ownership interest in Mont Belvieu Venture, LLC (the general partner of MB Storage) to Louis Dreyfus for approximately $137.6 million in cash (see Note 9 in the Notes to Unaudited Condensed Consolidated Financial Statements). We recognized a gain of approximately $59.6 million related to the sale of our equity interests, which is included in gain on sale of ownership interest in MB Storage in our statements of consolidated income.

Other income – net decreased $0.9 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, due to the receipt of various right-of-way payments in 2007.

Upstream Segment

The following table provides financial information for the Upstream Segment for the three months and nine months ended September 30, 2008 and 2007 (in thousands):

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	Increase (Decrease)	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007	Increase (Decrease)
Operating revenues: (1)						
Sales of petroleum products (2)	$ 4,012,714	$ 2,450,147	$ 1,562,567	$ 10,655,650	$ 6,215,043	$ 4,440,607
Transportation – Crude oil	15,759	12,332	3,427	48,491	32,702	15,789
Other	3,911	2,552	1,359	8,901	7,689	1,212
Total operating revenues	4,032,384	2,465,031	1,567,353	10,713,042	6,255,434	4,457,608
Costs and expenses: (1)						
Purchases of petroleum products (2)	3,976,775	2,421,285	1,555,490	10,554,953	6,121,329	4,433,624
Operating expense	17,693	13,146	4,547	43,738	41,984	1,754
Operating fuel and power	2,089	1,671	418	5,680	5,371	309
General and administrative	2,133	1,593	540	6,604	5,191	1,413
Depreciation and amortization	5,096	5,133	(37)	14,842	13,349	1,493
Taxes – other than income taxes.	1,696	1,601	95	5,355	4,550	805
Gains on sales of assets.	(1)	--	(1)	(1)	--	(1)
Total costs and expenses	4,005,481	2,444,429	1,561,052	10,631,171	6,191,774	4,439,397
Operating income	26,903	20,602	6,301	81,871	63,660	18,211
Equity earnings	2,748	1,073	1,675	9,925	4,310	5,615
Interest income	17	41	(24)	45	120	(75)
Other income – net	98	3	95	698	24	674
Earnings before interest	$ 29,766	$ 21,719	$ 8,047	$ 92,539	$ 68,114	$ 24,425

(1) Amounts in this table are presented after elimination of intercompany transactions, including sales and purchases of petroleum products.
(2) Petroleum products include crude oil, lubrication oils and specialty chemicals.

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, in each case, prior to the elimination of intercompany sales, revenues and purchases between wholly-owned subsidiaries. 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 nine months ended September 30, 2008 and 2007 is presented below (in thousands, except per barrel and per gallon amounts):

	For the Three Months Ended September 30,		Percentage Increase	For the Nine Months Ended September 30,		Percentage Increase
	2008	2007	(Decrease)	2008	2007	(Decrease)
Margins: (1)						
Crude oil marketing	$ 17,161	$ 15,305	12%	$ 53,060	$ 55,690	(5%)
Lubrication oil sales	4,184	2,267	85%	9,938	6,496	53%
Revenues: (1)						
Crude oil transportation	25,587	20,072	27%	73,047	53,886	36%
Crude oil terminaling	4,766	3,550	34%	13,143	10,344	27%
Total margins/revenues	$ 51,698	$ 41,194	25%	$ 149,188	$ 126,416	18%
Total barrels/gallons:						
Crude oil marketing (barrels) (1)	67,087	59,788	12%	186,285	173,792	7%
Lubrication oil volume (gallons)	6,255	3,971	58%	14,055	11,321	24%
Crude oil transportation (barrels)	26,460	24,899	6%	83,670	71,214	17%
Crude oil terminaling (barrels)	41,705	31,804	31%	114,564	103,003	11%
Margin per barrel or gallon:						
Crude oil marketing (per barrel) (1)	$ 0.256	$ 0.256	--	$ 0.285	$ 0.320	(11%)
Lubrication oil margin (per gallon)	0.669	0.571	17%	0.707	0.574	23%
Average tariff per barrel:						
Crude oil transportation	$ 0.967	$ 0.806	20%	$ 0.873	$ 0.757	15%
Crude oil terminaling	0.114	0.112	2%	0.115	0.100	14%

(1) Amounts in this table are presented prior to the eliminations of intercompany sales, revenues and purchases between TEPPCO Crude Oil, LLC ("TCO") and TEPPCO Crude Pipeline, LLC ("TCPL"), both of which are our wholly-owned subsidiaries. TCO is a significant shipper on TCPL. Crude oil marketing volumes also include inter-region transfers, which are transfers among TCO's various geographically managed regions.

The following table reconciles the Upstream Segment margin to operating income using the information presented in the statements of consolidated income and the Upstream Segment financial information on the preceding page (in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Sales of petroleum products	$ 4,012,714	$ 2,450,147	$ 10,655,650	$ 6,215,043
Transportation – Crude oil	15,759	12,332	48,491	32,702
Less: Purchases of petroleum products	(3,976,775)	(2,421,285)	(10,554,953)	(6,121,329)
Total margins/revenues	51,698	41,194	149,188	126,416
Other operating revenues	3,911	2,552	8,901	7,689
Net operating revenues	55,609	43,746	158,089	134,105
Operating expense	17,693	13,146	43,738	41,984
Operating fuel and power	2,089	1,671	5,680	5,371
General and administrative expense	2,133	1,593	6,604	5,191
Depreciation and amortization	5,096	5,133	14,842	13,349
Taxes – other than income taxes	1,696	1,601	5,355	4,550
Gains on sales of assets	(1)	--	(1)	--
Operating income	$ 26,903	$ 20,602	$ 81,871	$ 63,660

Three Months Ended September 30, 2008 Compared with Three Months Ended September 30, 2007

Sales of petroleum products and purchases of petroleum products increased $1,562.6 million and $1,555.5 million, respectively, for the three months ended September 30, 2008, compared with the three months ended September 30, 2007. Operating income increased $6.3 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007. The increases in sales and purchases were primarily a result of a 12% increase in volumes marketed related to the completion of organic growth projects, primarily on our West Texas system and increases in the price of crude oil. The average New York Mercantile Exchange ("NYMEX") price of crude oil was $118.22 per barrel for the three months ended September 30, 2008, compared with $75.15 per barrel for the three months ended September 30, 2007. Increased overall volumes transported and marketed, partially offset by increased costs and expenses discussed below, were the primary factors resulting in an increase in operating income.

Crude oil marketing margin increased $1.9 million, primarily due to increased volumes marketed and a $1.0 million increase in unrealized gains relating to marking crude oil grade and location swap contracts to current market value, partially offset by increased transportation costs, including higher fuel costs. Lubrication oil sales margin increased $1.9 million on higher volumes primarily due to increased sales of higher margin specialty chemicals and additional margin resulting from the acquisition of Quality Petroleum on August 1, 2008 (see Note 9 in the Notes to Unaudited Condensed Consolidated Financial Statements). Crude oil transportation revenues (prior to intercompany eliminations) increased $5.5 million and the average tariff per barrel increased 20% primarily due to higher transportation volumes on most of our crude oil gathering systems and increases in the tariff rates on certain systems in the third and fourth quarters of 2007 and in July 2008. Increased transportation revenues on our Red River and South Texas systems resulted from movements on higher tariff segments. Additionally, the completion of organic growth projects on our West Texas and South Texas systems increased transportation revenues and volumes on those systems. Our South Texas system benefitted from increased volumes coming into the system from U.S. Gulf of Mexico production and our West Texas system volumes increased due to higher truck and lease gathering volumes. Our Basin system volumes decreased due to decreased long-haul transportation from West Texas to Cushing, Oklahoma. Crude oil terminaling revenues increased $1.2 million as a result of increased pumpover volumes at Cushing, partially offset by decreased volumes at Midland, Texas, due to crude oil market conditions. Terminaling volumes increased 31% primarily due to the completion of three tanks in September 2007, the completion of a tank in August 2008 and as a result of a draw down in inventory at Cushing in September 2008 because several mid-continent and Midwest refiners were unable to obtain U.S. Gulf of Mexico crude oil supply.

Other operating revenues increased $1.4 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, primarily due to $0.9 million of other operating revenues resulting from the Quality Petroleum acquisition on August 1, 2008 and due to higher revenues from documentation and other services to support customers' trading activity at Midland and Cushing.

Costs and expenses increased $1,561.1 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007. Purchases of petroleum products, discussed above, increased $1,555.5 million compared with the prior year period. Operating expenses increased $4.5 million from the prior year period, primarily due to a $3.7 million increase in pipeline operating and maintenance expenses primarily related to periodic tank maintenance requirements pursuant to API 653 in the 2008 period, $1.1 million of expense related to initial project development costs for Texas Offshore Port System, a $0.7 million increase in labor and benefits expense, a $0.6 million increase in pipeline inspection and repair costs associated with our integrity management program and a $0.4 million LCM adjustment, partially offset by a $1.9 million decrease in product measurement losses. Operating fuel and power increased $0.4 million primarily as a result of higher fuel costs and higher transportation volumes. General and administrative expenses increased $0.5 million, primarily due to higher legal expenses. Depreciation and amortization expense and taxes – other than income remained relatively unchanged between periods.

Equity earnings from our investment in Seaway increased $1.7 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007. Our sharing ratio of the revenue and expense of Seaway for 2008 and 2007 is 40% (see Note 8 in the Notes to Unaudited Condensed Consolidated Financial Statements). Equity earnings from our investment in Seaway increased primarily due to increased transportation revenues from volumes transported on a spot basis, which are transported at higher tariff rates, and an increase in long-haul transportation volumes compared to the prior year period as a result of the unexpected temporary shutdown of several regional refineries for maintenance and repairs in the 2007 period. These increases were partially offset by a decrease in transportation volumes resulting from downtime of the long-haul system and the Texas City terminal resulting from Hurricane Ike and increased pipeline operating and maintenance expenses, including expenses of $0.4 million for repairs and maintenance resulting from Hurricane Ike. Long-haul volumes on Seaway averaged 192,636 barrels per day during the three months ended September 30, 2008, compared with 103,740 barrels per day during the three months ended September 30, 2007. For further information on distributions from Seaway, see Note 8 in the Notes to Unaudited Condensed Consolidated Financial Statements.

Nine Months Ended September 30, 2008 Compared with Nine Months Ended September 30, 2007

Sales of petroleum products and purchases of petroleum products increased $4,440.6 million and $4,433.6 million, respectively, for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007. Operating income increased $18.2 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007. The increases in sales and purchases were primarily a result of increased volumes marketed and increases in the price of crude oil. The average NYMEX price of crude oil was $113.28 per barrel for the nine months ended September 30, 2008, compared with $66.15 per barrel for the nine months ended September 30, 2007. Increased volumes transported and marketed, partially offset by increased costs and expenses discussed below, were the primary factors resulting in an increase in operating income.

Crude oil marketing margin decreased $2.6 million, primarily due to increased transportation costs, including increased fuel costs, partially offset by increased volumes marketed and a $0.7 million increase in unrealized gains relating to marking crude oil grade and location swap contracts to current market value. Lubrication oil sales margin increased $3.4 million on higher volumes primarily due to increased sales of higher margin specialty chemicals and additional margin resulting from the acquisition of Quality Petroleum on August 1, 2008. Crude oil transportation revenues (prior to intercompany eliminations) increased $19.2 million primarily due to higher transportation volumes on most of our crude oil gathering systems and increases in the tariff rates on certain systems in 2007 and in July 2008. Increased transportation revenues on our Red River, South Texas and Basin systems resulted from movements on higher tariff segments. Additionally, the completion of organic growth projects on our West Texas and South Texas systems increased transportation revenues and volumes on those systems. Crude oil terminaling revenues increased $2.8 million as a result of increased pumpover volumes at Cushing, partially offset by decreased volumes at Midland due to crude oil market conditions. Terminaling volumes increased 11% primarily due to the completion of three tanks in September 2007, the completion of a tank in August 2008 and as a result of a draw down in inventory at Cushing in September 2008 because several mid-continent and Midwest refiners were unable to obtain U.S. Gulf of Mexico crude oil supply.

Other operating revenues increased $1.2 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, primarily due to $0.9 million of other operating revenues resulting from the Quality Petroleum acquisition on August 1, 2008 and due to higher revenues from documentation and other services to support customers’ trading activity at Midland and Cushing.

Costs and expenses increased $4,439.4 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007. Purchases of petroleum products, discussed above, increased $4,433.6 million compared with the prior year period. Operating expenses increased $1.8 million from the prior year period, primarily due to a $7.5 million increase in pipeline operating and maintenance expenses primarily related to periodic tank maintenance requirements, $1.1 million of expense related to initial project development costs for Texas Offshore Port System and a $0.4 million increase in pipeline inspection and repair costs associated with our integrity management program, partially offset by a $5.7 million decrease in product measurement losses, a $0.7 million decrease in insurance premiums and a $0.4 million decrease in labor and benefits expense. Operating fuel and power increased $0.3 million primarily as a result of higher fuel costs and higher transportation volumes.

General and administrative expenses increased $1.4 million, primarily due to a $0.5 million write-off of project costs, a $0.5 million increase in labor and benefits expense and a $0.3 million increase in professional services and supplies expense. Depreciation and amortization expense increased $1.5 million primarily due to assets placed into service in 2007. Taxes – other than income taxes increased $0.8 million due to increases in property tax accruals and a higher property asset base in 2008.

Equity earnings from our investment in Seaway increased $5.6 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007. Equity earnings from our investment in Seaway increased primarily due to increased transportation revenues from volumes transported on a spot basis, which are transported at higher tariff rates, and an increase in long-haul transportation volumes compared to the prior year period as a result of the unexpected temporary shutdown of several regional refineries for maintenance and repairs in the 2007 period. These increases were partially offset by a decrease in transportation volumes resulting from the effects of Hurricane Ike as discussed above. Increased pipeline operating and maintenance expenses, including expenses of $0.4 million of repairs and maintenance resulting from Hurricane Ike, were partially offset by lower product measurement losses. Long-haul volumes on Seaway averaged 191,941 barrels per day during the nine months ended September 30, 2008, compared with 136,394 barrels per day during the nine months ended September 30, 2007.

Other income – net increased $0.7 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, primarily due to the receipt of $0.6 million of royalty income.

Midstream Segment

The following table provides financial information for the Midstream Segment for the three months and nine months ended September 30, 2008 and 2007 (in thousands):

	For the Three Months Ended September 30,		Increase	For the Nine Months Ended September 30,		Increase
	2008	2007	(Decrease)	2008	2007	(Decrease)
Operating revenues: (1)						
Gathering – Natural gas – Val Verde	$ 14,620	$ 15,429	$ (809)	$ 42,822	$ 46,289	$ (3,467)
Transportation – NGLs (1)	12,560	12,023	537	38,218	34,062	4,156
Other	3,145	3,698	(553)	9,970	10,606	(636)
Total operating revenues	30,325	31,150	(825)	91,010	90,957	53
Costs and expenses:						
Operating expense	6,746	7,064	(318)	16,120	21,095	(4,975)
Operating fuel and power	4,838	3,951	887	12,999	10,537	2,462
General and administrative expense	2,196	1,850	346	7,522	6,695	827
Depreciation and amortization	9,982	10,071	(89)	29,573	30,244	(671)
Taxes – other than income taxes	760	749	11	2,329	2,151	178
Total costs and expenses	24,522	23,685	837	68,543	70,722	(2,179)
Operating income	5,803	7,465	(1,662)	22,467	20,235	2,232
Equity earnings – Jonah	21,863	21,056	807	67,444	62,430	5,014
Interest income	97	182	(85)	326	459	(133)
Other income – net	--	--	--	--	--	--
Earnings before interest	$ 27,763	$ 28,703	$ (940)	$ 90,237	$ 83,124	$ 7,113

(1) Includes transportation revenue from Enterprise Products Partners of $3.4 million, $3.5 million, $10.2 million and $13.2 million for the three months and nine months ended September 30, 2008 and 2007, respectively.

The following table presents volume and average rate information for the three months and nine months ended September 30, 2008 and 2007 (in thousands, except average fee and average rate amounts and as otherwise indicated):

	For the Three Months Ended September 30,		Percentage Increase	For the Nine Months Ended September 30,		Percentage Increase
	2008	2007	(Decrease)	2008	2007	(Decrease)
Gathering – Natural Gas – Jonah: (1)						
MMcf	184,093	151,845	21%	524,668	424,304	24%
BBtus	202,536	167,498	21%	579,687	467,808	24%
Average fee per MMcf	$ 0.250	$ 0.239	5%	$ 0.255	$ 0.230	11%
Average fee per MMBtu	$ 0.228	$ 0.216	5%	$ 0.231	$ 0.209	11%
Gathering – Natural Gas – Val Verde: (1)						
MMcf	43,927	44,225	(1%)	123,731	131,279	(6%)
BBtu	39,437	39,311	--	110,419	116,408	(5%)
Average fee per MMcf	$ 0.333	$ 0.349	(5%)	$ 0.346	$ 0.353	(2%)
Average fee per MMBtu	$ 0.371	$ 0.392	(5%)	$ 0.388	$ 0.398	(2%)
Transportation – NGLs:						
Transportation barrels	14,564	16,612	(12%)	47,085	47,455	(1%)
Lease barrels (2)	2,528	3,702	(32%)	8,421	9,370	(10%)
Average rate per barrel	$ 0.810	$ 0.683	19%	$ 0.763	$ 0.683	12%
Natural Gas Sales – Jonah:						
BBtu	1,092	3,931	(72%)	3,934	11,978	(67%)
Average fee per MMBtu	$ 5.88	$ 3.01	95%	$ 7.06	$ 4.28	65%
Fractionation – NGLs:						
Barrels	1,036	1,044	(1%)	3,180	3,097	3%
Average rate per barrel	$ 1.785	$ 1.781	--	$ 1.742	$ 1.776	(2%)
Sales – Condensate – Jonah: (3)						
Barrels	1.9	0.9	111%	62.3	70.6	(12%)
Average rate per barrel	$ 105.56	$ 67.34	57%	$ 84.07	$ 54.76	54%

(1) The majority of volumes in Val Verde's contracts are measured in MMcf, while the majority of volumes in Jonah's contracts are measured in MMBtu. Both measures are shown for each asset for comparability purposes.
(2) Revenues associated with capacity leases are classified as other operating revenues in our statements of consolidated income.
(3) All of Jonah's condensate volumes are sold to TCO.

Three Months Ended September 30, 2008 Compared with Three Months Ended September 30, 2007

Natural gas gathering revenues from the Val Verde system decreased $0.8 million, and volumes gathered decreased 0.3 Bcf for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, primarily due to the natural decline of coal bed methane production in the fields in which the Val Verde gathering system operates. For the three months ended September 30, 2008, Val Verde's gathering volumes averaged 478 MMcf per day, compared with 481 MMcf per day for the three months ended September 30, 2007. Val Verde's average natural gas gathering fees decreased 5% primarily due to higher volumes from a third party natural gas connection that has lower rates and lower gathering volumes, partially offset by annual rate escalations.

Revenues from the transportation of NGLs increased $0.5 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, primarily due to an increase in the average rate on the Chaparral Pipeline as a result of transporting a higher percentage of long-haul volumes on the pipeline and an increase in the average rate on the Panola Pipeline, partially offset by lower transportation volumes due to the unexpected reduction of deliveries on the Chaparral and Panola Pipelines resulting from the effects of Hurricane Ike.

Other operating revenues decreased $0.6 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, primarily due to decreases on the Chaparral and Panola Pipelines as a result of decreased revenues and volumes from pipeline capacity leases. Volumes transported under pipeline capacity leases decreased 32% during the three months ended September 30, 2008, compared with the three months ended September 30, 2007, due to customers shipping less NGLs under the capacity lease agreements and due to the effects of Hurricane Ike, as discussed above.

Costs and expenses increased $0.8 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007. Operating expenses decreased $0.3 million from the prior year period, primarily due to a $1.0 million decrease as a result of lower product measurement losses, a $0.4 million decrease in pipeline inspection and repair costs associated with our integrity management program and a $0.4 million decrease in insurance premiums, partially offset by a $1.2 million LCM adjustment. Operating fuel and power increased $0.9 million primarily due to higher power costs on the Chaparral Pipeline. General and administrative expenses increased $0.3 million due to higher professional services expense. Depreciation and amortization expense and taxes – other than income taxes remained relatively unchanged between periods.

Equity earnings from our investment in Jonah increased $0.8 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, primarily due to an increase in natural gas gathering revenues, partially offset by a $3.5 million increase in operating, general and administrative expenses and a $3.0 million increase in depreciation and amortization expense. For the three months ended September 30, 2008, our sharing in the earnings of Jonah was 80.64%, compared with 84.18% in the prior year period, as a result of certain milestones provided for in the joint venture agreement being reached in the construction of the Phase V expansion (see Note 8 in the Notes to Unaudited Condensed Consolidated Financial Statements). Jonah's depreciation and amortization expense increased $3.0 million primarily relating to the Phase V expansion being placed in service. Jonah's natural gas gathering revenues increased $9.8 million and gathering volumes increased 32.2 Bcf primarily as a result of the completion of the Phase V expansion, partially offset by a decrease in gathering volumes resulting from the temporary shutdown of a connecting pipeline system for maintenance. For the three months ended September 30, 2008 and 2007, Jonah's gathering volumes averaged approximately 2.0 Bcf per day and 1.7 Bcf per day, respectively.

The decrease in Jonah's natural gas sales volumes for the three months ended September 30, 2008, compared with the prior year period, was primarily a result of certain shippers selling gas themselves, rather than through Jonah. The increase in Jonah's natural gas sales average fee per MMBtu was primarily a result of higher market prices in the 2008 period. As a result of lower gathering system pressures, more condensate was being removed at the wellhead and sold by producers, instead of being gathered by Jonah, resulting in a decrease in Jonah's condensate sales volumes from the prior year period. The increase in Jonah's average condensate rate per barrel was primarily a result of higher market prices in the current period compared with the three months ended September 30, 2007.

Nine Months Ended September 30, 2008 Compared with Nine Months Ended September 30, 2007

Natural gas gathering revenues from the Val Verde system decreased $3.5 million, and volumes gathered decreased 7.5 Bcf for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, primarily due to lower production as a result of more severe winter weather during the first quarter of 2008 and the natural decline of coal bed methane production in the fields in which the Val Verde gathering system operates. For the nine months ended September 30, 2008, Val Verde's gathering volumes averaged 452 MMcf per day, compared with 481 MMcf per day for the nine months ended September 30, 2007. Val Verde's average natural gas gathering fees decreased 2% primarily due to higher volumes from a third party natural gas connection that has lower rates and lower gathering volumes, partially offset by annual rate escalations.

Revenues from the transportation of NGLs increased $4.2 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, primarily due to an increase in the average rate on the Chaparral Pipeline as a result of transporting a higher percentage of long-haul volumes on the system and an increase in the average rate on the Panola Pipeline, partially offset by lower transportation volumes due to the unexpected reduction of deliveries on the Chaparral and Panola Pipelines resulting from the effects of Hurricane Ike, as discussed above.

Other operating revenues decreased $0.6 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, primarily due to decreases on the Chaparral and Panola Pipelines as a result of decreased revenues and volumes from pipeline capacity leases. Volumes transported under pipeline capacity leases decreased 10% during the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, due to customers shipping less NGLs under the capacity lease agreements and due to the effects of Hurricane Ike.

Costs and expenses decreased $2.2 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007. Operating expenses decreased $5.0 million from the prior year period, primarily due to a $4.5 million decrease as a result of lower product measurement losses, a $2.3 million decrease in insurance premiums, a $1.4 million decrease in pipeline inspection and repair costs associated with our integrity management program and a $0.7 million decrease in labor and benefits expense, partially offset by a $2.5 million increase in pipeline operating and maintenance expenses and $1.3 million in LCM adjustments. Operating fuel and power increased $2.5 million primarily due to higher power costs on the Chaparral Pipeline. General and administrative expenses increased $0.8 million primarily due to higher labor and benefits expense and higher professional services expense. Depreciation and amortization expense decreased $0.7 million primarily due to a decrease in amortization expense on Val Verde as a result of a decrease in volumes on contracts which are included in intangible assets and amortized under the units-of-production method. Taxes – other than income taxes increased $0.2 million primarily due to true-ups of property tax accruals.

Equity earnings from our investment in Jonah increased $5.0 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007. Earnings increased primarily due to a $36.4 million increase in natural gas gathering revenues and an increase in volumes from the completion of the Phase V expansion, partially offset by an $11.6 million increase in depreciation and amortization expense primarily relating to portions of the Phase V expansion being placed in service as they were completed and a $3.2 million increase in operating, general and administrative expenses. For the nine months ended September 30, 2008 and 2007, Jonah's gathering volumes averaged approximately 1.9 Bcf per day and 1.5 Bcf per day, respectively, and total volumes gathered increased 100.3 Bcf. For the nine months ended September 30, 2008, our sharing in the earnings of Jonah was 80.64%, compared with 93.26% in the prior year period, as a result of certain milestones provided for in the joint venture agreement being reached in the construction of the Phase V expansion (see Note 8 in the Notes to Unaudited Condensed Consolidated Financial Statements).

The decrease in Jonah's natural gas sales volumes for the nine months ended September 30, 2008, compared with the prior year period, was primarily a result of certain shippers selling gas themselves, rather than through Jonah. The increase in Jonah's natural gas sales average fee per MMBtu was primarily a result of higher market prices in the 2008 period. As a result of lower gathering system pressures, more condensate was being removed at the wellhead and sold by producers, instead of being gathered by Jonah, resulting in a decrease in Jonah's condensate sales volumes from the prior year period. The increase in Jonah's average condensate rate per barrel was primarily a result of higher market prices in the current period compared with the nine months ended September 30, 2007.

Marine Services Segment

We conduct business in our Marine Services Segment through TEPPCO Marine Services. Demand for our marine transportation services is driven primarily by demand for refined products, crude oil and other hydrocarbon-based products in the areas in which we operate. We generate revenue in this segment primarily by charging customers for the inland and offshore transportation and distribution of their products utilizing our 113 tank barges and 51 tow boats. We also provide offshore well-testing and other offshore services. Approximately 6 of our tow boats and 8 of our tank barges are dedicated to offshore activities. We do not assume ownership of the products we transport in this segment.

Our transportation services are generally provided under term contracts (also referred to as affreightment contracts), which are agreements with specific customers to transport cargo from within designated operating areas at set day rates or a set fee per cargo movement. Most of the inland term contracts have one-year terms with the remainder having terms of up to two years. Substantially all of the inland contracts have renewal options, which are exercisable subject to agreement on rates applicable to the option terms. Since our acquisition of Cenac and Horizon (see Note 9 in the Notes to Unaudited Condensed Consolidated Financial Statements), as the customer contracts become subject to annual renewal, we have obtained renewals of substantially all contracts at increased day rates. Most of the offshore service and transportation contracts have up to one-year terms with renewal options, which are exercisable subject to agreement on rates applicable to the option terms, or are spot contracts. A spot contract is an agreement with a customer to move cargo within designated operating areas for a rate negotiated at the time the cargo movement takes place.

As is typical for inland and offshore affreightment contracts, the term contracts establish set day rates but do not include revenue or volume guarantees. Most of the contracts include escalation provisions to recover specific increased operating costs such as incremental increases in labor. The costs of fuel and other specified operational fees and costs are directly reimbursed by the customer under most of the contracts. We are responsible for the remaining operating costs, such as equipment maintenance costs, various inspection costs, the cost of maintaining insurance coverage on the vessels under these contracts, and for other operating costs under our other contracts that do not contain such reimbursement or escalation provisions.

The following table provides financial information for the Marine Services Segment for the three months and nine months ended September 30, 2008 and 2007 (in thousands):

	For the Three Months Ended September 30,		Increase	For the Nine Months Ended September 30,		Increase
	2008	2007	(Decrease)	2008	2007	(Decrease)
Operating revenues:						
Transportation – Marine	$ 46,018	$ --	$ 46,018	$ 119,584	$ --	$ 119,584
Other	--	--	--	6	--	6
Total operating revenues	46,018	--	46,018	119,590	--	119,590
Costs and expenses:						
Operating expense	18,199	--	18,199	45,794	--	45,794
Operating fuel and power	10,197	--	10,197	27,916	--	27,916
General and administrative	2,305	--	2,305	4,119	--	4,119
Depreciation and amortization	6,257	--	6,257	16,345	--	16,345
Taxes – other than income taxes	706	--	706	1,844	--	1,844
Total costs and expenses	37,664	--	37,664	96,018	--	96,018
Operating income	8,354	--	8,354	23,572	--	23,572
Interest income	5	--	5	11	--	11
Earnings before interest	$ 8,359	$ --	$ 8,359	$ 23,583	$ --	$ 23,583

Three Months Ended September 30, 2008 Compared with Three Months Ended September 30, 2007

Revenues from marine transportation were $46.0 million for the three months ended September 30, 2008, of which $41.6 million related to inland transportation services and $4.4 million related to offshore transportation and well-testing services. Inland and offshore transportation service revenue included $11.2 million and $0.4 million, respectively, of reimbursements for the cost of fuel and other specified operational fees reimbursed by customers. Revenues were primarily influenced by rates on term contracts along with industry demand, high utilization rates of tank barges and reimbursements of costs of fuel and other specified operational fees that are recovered under most of the transportation contracts.

Costs and expenses were $37.7 million for the three months ended September 30, 2008. Operating expenses were $18.2 million, consisting primarily of $9.2 million of payments under the transitional operating agreement for vessel personnel salaries, related employee benefits and other expenses, $2.7 million of tow boat and tank barge maintenance expenses, $2.2 million in operating supplies and expenses, $1.8 million for third-party services, and $0.7 million in insurance premiums. Under the transitional operating agreement, we reimburse Cenac for personnel salaries and related employee benefit expenses, certain repairs and maintenance expenses and insurance premiums on our equipment, as well as payment of a monthly service fee. Operating fuel and power was $10.2 million relating to diesel fuel consumed under the term contracts, under which substantially all fuel costs are directly reimbursed by the customer to recover the cost of fuel. General and administrative expenses were $2.3 million, consisting primarily of a $1.3 million write-off of receivables as a result of a customer bankruptcy and the remainder being the monthly service fee and overhead fees that we paid to Cenac under the transitional operating agreement. Depreciation and amortization expense was $6.3 million, consisting of $4.3 million of depreciation expense on tow boats and tank barges and $2.0 million of amortization expense related to customer relationship intangible assets, non-compete agreements and other intangible assets acquired in the Cenac and Horizon acquisitions. Taxes – other than income taxes was $0.7 million and related primarily to payroll taxes.

Nine Months Ended September 30, 2008 Compared with Nine Months Ended September 30, 2007

Revenues from marine transportation were $119.6 million for the nine months ended September 30, 2008, of which $101.9 million related to inland transportation services and $17.7 million related to offshore transportation and well-testing services.   Inland and offshore transportation service revenue included $30.2 million and $1.7 million, respectively, of reimbursements for the cost of fuel and other specified operational fees reimbursed by customers. Revenues were primarily influenced by rates on term contracts along with industry demand, high utilization rates of tank barges and reimbursements of costs of fuel and other specified operational fees that are recovered under most of the transportation contracts.

Costs and expenses were $96.0 million for the nine months ended September 30, 2008. Operating expenses were $45.8 million, consisting primarily of $25.6 million of payments under the transitional operating agreement for vessel personnel salaries, related employee benefits and other expenses, $6.2 million for third-party services, $5.7 million of tow boat and tank barge maintenance expenses, $5.1 million in operating supplies and expenses, and $1.9 million in insurance premiums. Operating fuel and power was $27.9 million relating to diesel fuel consumed under the term contracts, under which substantially all fuel costs are directly reimbursed by the customer to recover the cost of fuel. General and administrative expenses were $4.1 million, consisting primarily of $2.8 million related to the monthly service fee and overhead fees that we paid to Cenac under the transitional operating agreement and a $1.3 million write-off of receivables as a result of a customer bankruptcy. Depreciation and amortization expense was $16.3 million, consisting of $11.0 million of depreciation expense on tow boats and tank barges and $5.3 million of amortization expense related to customer relationship intangible assets, non-compete agreements and other intangible assets acquired in the Cenac and Horizon acquisitions. Taxes – other than income taxes was $1.8 million and related primarily to payroll taxes.

Interest Expense and Capitalized Interest

Three Months Ended September 30, 2008 Compared with Three Months Ended September 30, 2007

Interest expense increased $9.7 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, primarily due to higher outstanding borrowings in the 2008 period, partially offset by lower short-term floating interest rates in the 2008 period.

Capitalized interest (included in interest expense, net in our statements of consolidated income) increased $2.3 million for the three months ended September 30, 2008, compared with the three months ended September 30, 2007, primarily due to higher construction work-in-progress balances in the 2008 period as compared to the 2007 period.

Nine Months Ended September 30, 2008 Compared with Nine Months Ended September 30, 2007

Interest expense increased $39.4 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, primarily due to higher outstanding borrowings in the 2008 period and $8.7 million in interest expense recognized upon the redemption of the 7.51% TE Products Senior Notes on January 28, 2008. Of the $8.7 million of expense, $6.6 million related to a make-whole premium paid with the redemption of the senior notes (see Note 11 in the Notes to Unaudited Condensed Consolidated Financial Statements), $1.0 million related to the remaining unamortized interest rate swap loss that had been deferred as an adjustment to the carrying value of the senior notes (see Note 5 in the Notes to Unaudited Condensed Consolidated Financial Statements) and $1.1 million related to unamortized debt issuance costs on the senior notes. Additionally, the increase in interest expense was due to $3.6 million of interest expense in the 2008 period resulting from interest payments hedged under treasury locks not occurring as forecasted (see Note 5 in the Notes to Unaudited Condensed Consolidated Financial Statements). These increases were partially offset by lower short-term floating interest rates in the 2008 period.

Capitalized interest (included in interest expense, net in our statements of consolidated income) increased $5.4 million for the nine months ended September 30, 2008, compared with the nine months ended September 30, 2007, primarily due to higher construction work-in-progress balances in the 2008 period as compared to the 2007 period.

Income Taxes – Revised Texas Franchise Tax

Provision for income taxes is applicable to our state tax obligations under the Revised Texas Franchise Tax enacted in May 2006. At September 30, 2008 and December 31, 2007, we had current tax liabilities of $2.3 million and $1.2 million, respectively, and deferred tax assets of less than $0.1 million and less than $0.1 million, respectively. During the three months and nine months ended September 30, 2008 and 2007, we recorded increases in current income tax liabilities of $1.1 million, less than $0.1 million, $2.9 million and $0.9 million, respectively. During the nine months ended September 30, 2007, we recorded a $0.7 million reduction to deferred tax liability. The offsetting net charges to deferred tax expense and income tax expense are shown on our statements of consolidated income as provision for income taxes.

Financial Condition and Liquidity

Cash generated from operations, borrowings under our credit facilities and debt and equity offerings are our primary sources of liquidity. At September 30, 2008 and December 31, 2007, we had working capital deficits of $7.8 million and $431.2 million, respectively. Of the $431.2 million deficit at December 31, 2007, $354.0 million related to the classification of the TE Products' Senior Notes as short-term (see Note 11 in the Notes to Unaudited Condensed Consolidated Financial Statements and Credit Facilities below). At September 30, 2008, we had approximately $600.0 million in available borrowing capacity under our variable rate revolving credit facility to cover any working capital needs (see Note 11 in the Notes to Unaudited Condensed Consolidated Financial

Statements and Credit Facilities below). Cash flows for the nine months ended September 30, 2008 and 2007 were as follows (in thousands):

	For the Nine Months Ended September 30,	
	2008	2007
Cash provided by (used in):		
Operating activities	$ 294,869	$ 219,186
Investing activities	(673,758)	(182,643)
Financing activities	378,921	(36,585)

Operating Activities

Net cash flow provided by operating activities was $294.9 million for the nine months ended September 30, 2008 compared to $219.2 million for the nine months ended September 30, 2007. The following were the principal factors resulting in the $75.7 million increase in net cash flows provided by operating activities:

§ Cash flow from operating activities increased due to the timing of cash receipts and cash disbursements related to working capital components.

§ Cash distributions received from unconsolidated affiliates increased $22.0 million. Distributions from our equity investment in Jonah increased $34.2 million primarily due to increased revenues and volumes generated from completion of the Phase V expansion. Distributions received from our equity investment in Seaway decreased $1.8 million primarily due to its operating cash requirements.   In the 2007 period, we received distributions from our equity investment in MB Storage of $10.4 million. We sold our interest in MB Storage on March 1, 2007.

§ Cash paid for interest, net of amounts capitalized, increased $8.8 million period-to-period primarily due to the increase in debt outstanding, including higher outstanding balances on our variable rate revolving credit facility. Excluding the effects of hedging activities and interest capitalized during the year ended December 31, 2008, we expect interest payments on our fixed rate senior notes and junior subordinated notes for 2008 to be approximately $123.1 million. We expect to make our interest payments with cash flows from operating activities.

Investing Activities

Net cash flow used in investing activities was $673.8 million for the nine months ended September 30, 2008 compared to $182.6 million for the nine months ended September 30, 2007. The following were the principal factors resulting in the $491.2 million increase in net cash flows used in investing activities:

§ Cash used for business combinations was $351.9 million during the nine months ended September 30, 2008, of which $258.1 million was for the Cenac acquisition, $87.5 million was for the Horizon acquisition and $6.3 million was for the Quality Petroleum acquisition in August 2008 (see Note 9 in the Notes to Unaudited Condensed Consolidated Financial Statements).

§ Capital expenditures increased $51.0 million primarily due to an increase in organic growth projects period-to-period and higher spending to sustain existing operations, including pipeline integrity (see “Other Considerations – Future Capital Needs and Commitments” below). Cash paid for linefill on assets owned decreased $15.1 million period-to-period primarily due to the timing of completion of organic growth projects in our Upstream Segment.

§ Proceeds from the sales of assets and ownership interests during the nine months ended September 30, 2007 were $165.1 million, which includes $137.3 million from the sale of TE Products’ ownership interests in MB Storage and its general partner and $18.5 million for the sale of other Downstream Segment assets, all to Louis Dreyfus on March 1, 2007; $8.0 million for the sale of Downstream Segment assets to Enterprise Products Partners in January 2007 (see Note 9 in the Notes to Unaudited Condensed Consolidated Financial Statements) and $1.3 million for the sale of various Upstream Segment assets in the third quarter of 2007.

§ Investments in unconsolidated affiliates decreased $44.0 million, which includes an $11.1 million decrease in contributions to Centennial and a $32.9 million decrease in contributions to Jonah primarily related to timing of capital expenditures on its Phase V expansion. During the nine months ended September 30, 2007, TE Products contributed $11.1 million to Centennial, of which $6.1 million was for contractual obligations that were created upon formation of Centennial and $5.0 million was for debt service requirements.

§ Cash paid for the acquisition of assets for the nine months ended September 30, 2007 was $12.7 million, of which $6.0 million was for Downstream Segment assets and $6.7 million was for Upstream Segment assets.

§ During the nine months ended September 30, 2008 and 2007, we paid $0.3 million and $2.5 million, respectively, related to customer reimbursable commitments.

§ At September 30, 2007, we had restricted cash of $2.9 million related to a U.S. Department of Justice penalty that was subsequently paid in the fourth quarter of 2007.

Financing Activities

Cash flows provided by financing activities totaled $378.9 million for the nine months ended September 30, 2008, compared to cash flows used in financing activities of $36.6 million for the nine months ended September 30, 2007. The following were the principal factors resulting in the $415.5 million increase in cash provided by financing activities:

§ During the nine months ended September 30, 2008, we used $1.0 billion of proceeds from our term credit agreement (i) to fund the cash portion of our Cenac and Horizon acquisitions, (ii) to fund the redemption of our 7.51% TE Products Senior Notes in January 2008 and the repayment of our 6.45% TE Products Senior Notes, which matured in January 2008, (iii) to repay $63.2 million of debt assumed in the Cenac acquisition, and (iv) for other general partnership purposes. We used the proceeds from the issuance of senior notes in March 2008 to repay the outstanding balance of $1.0 billion under the term credit agreement (see Note 11 in the Notes to Unaudited Condensed Consolidated Financial Statements). Debt issuance costs paid during the nine months ended September 30, 2008 were $9.9 million.

§ We received $295.8 million from the issuance in May 2007 of our 7.000% junior subordinated notes due September 2067 (net of debt issuance costs of $3.8 million) (see Note 11 in the Notes to Unaudited Condensed Consolidated Financial Statements).

§ Net repayments under our revolving credit facility increased $52.3 million.

§ We paid $52.1 million to settle treasury locks in March 2008 (see Note 5 in the Notes to Unaudited Condensed Consolidated Financial Statements) upon the issuance of senior notes. We received $1.4 million in proceeds from the termination of treasury locks in May 2007, and we paid $1.2 million for the termination of an interest rate swap in September 2007.

§ Cash distributions to our partners increased $17.2 million period-to-period due to an increase in the number of Units outstanding and an increase in our quarterly cash distribution rate per Unit. We paid cash distributions of $236.8 million ($2.115 per Unit) and $219.6 million ($2.045 per Unit) during the nine months ended September 30, 2008 and 2007, respectively. Additionally, we declared a cash distribution of $0.725 per Unit for the quarter ended September 30, 2008. We paid the distribution of $91.2 million on November 6, 2008 to unitholders of record on October 31, 2008.

§ We received $257.0 million in net proceeds from an underwritten equity offering in September 2008 from the public issuance of 9.2 million Units (see Note 12 in the Notes to Unaudited Condensed Consolidated Financial Statements) and $7.0 million from the sale of 241,380 unregistered Units to TEPPCO Unit (see Note 3 in the Notes to Unaudited Condensed Consolidated Financial Statements).

§ Net proceeds from to the issuance of Units to employees under the employee unit purchase plan and the issuance of Units in connection with our distribution reinvestment plan ("DRIP") were $7.3 million for the nine months ended September 30, 2008, compared to $0.1 million for the nine months ended September 30, 2007 (see Note 12 in the Notes to Unaudited Condensed Consolidated Financial Statements).

Other Considerations

Equity Offering and Registration Statement

In September 2008, we filed a universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities and removed from registration securities remaining under our previous universal shelf registration statement.

On September 9, 2008, we issued and sold in an underwritten public offering 9.2 million Units at a price to the public of $29.00 per Unit, including 1.2 million Units sold upon exercise of the underwriters' over-allotment option granted in connection with the offering. The proceeds from the offering, net of underwriting discount and offering expenses, totaled approximately $257.0 million. Concurrently with this offering, we sold 241,380 unregistered Units at the public offering price of $29.00 to TEPPCO Unit (see "Recent Developments" above). The net proceeds from the offering and the unregistered issuance to TEPPCO Unit were used to reduce indebtedness under our revolving credit facility.

We also have on file with the SEC a registration statement registering the issuance of up to 10,000,000 Units in connection with our DRIP. The DRIP provides unitholders of record and beneficial owners of our Units a voluntary means by which they can increase the number of Units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional Units of our Partnership. As of September 30, 2008, 245,084 Units have been issued since the implementation of the DRIP, generating $7.3 million in net proceeds that we used for general partnership purposes. In November 2008, affiliates of EPCO reinvested $3.3 million in Units issued under the DRIP.

Credit Facilities

We have in place an unsecured revolving credit facility, including the issuance of letters of credit ("Revolving Credit Facility"), which matures on December 12, 2012. The Revolving Credit Facility allows us to request unlimited one-year extensions of the maturity date, subject to lender approval and satisfaction of certain other conditions. In July 2008, we received confirmations from participating lenders making effective our exercise of the accordion feature under the facility, and increased the bank commitments thereunder from $700.0 million to $950.0 million. The aggregate outstanding principal amount of swing line loans or same day borrowings permitted under the Revolving Credit Facility is $40.0 million. The interest rate is based, at our option, on either the lender's base rate, or LIBOR rate, plus a margin, in effect at the time of the borrowings. At September 30, 2008, $324.7 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 3.56%, leaving approximately $600.0 million in available borrowing capacity. At September 30, 2008, we were in compliance with the covenants of the Revolving Credit Facility.

During September 2008, Lehman Brothers Bank, FSB ("Lehman"), which had a 4.05% participation in our Revolving Credit Facility, stopped funding its commitment following the bankruptcy filing of its parent. Assuming that future fundings are not received for the Lehman percentage commitment, aggregate available capacity would be reduced by approximately $38.5 million.

We had in place a senior unsecured term credit agreement ("Term Credit Agreement"), with a borrowing capacity of $1.0 billion and a maturity date of December 19, 2008. During the first quarter of 2008, we borrowed $1.0 billion to finance the retirement of TE Products' senior notes, the cash portion of our Cenac and Horizon acquisitions and other partnership purposes. In March 2008, we repaid the outstanding balance with proceeds from the issuance of senior notes and other cash on hand and terminated the credit agreement.

See Note 11 in the Notes to Unaudited Condensed Consolidated Financial Statements for further information on these credit facilities.

Senior Notes

On March 27, 2008, we issued and sold in an underwritten public offering (i) $250.0 million principal amount of 5.90% Senior Notes due 2013, (ii) $350.0 million principal amount of 6.65% Senior Notes due 2018, and (iii) $400.0 million principal amount of 7.55% Senior Notes due 2038. The proceeds of this offering were used to repay borrowings outstanding under our Term Credit Agreement, which was terminated in March 2008 (see Note 11 in the Notes to Unaudited Condensed Consolidated Financial Statements). The Senior Notes were issued at discounts of $0.2 million, $1.3 million and $2.2 million, respectively, and are being accreted to their face value over the applicable terms of the senior 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 50 basis points. The indentures governing our senior notes contain covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indentures do not limit our ability to incur additional indebtedness. At September 30, 2008, we were in compliance with the covenants of these senior notes.

Retirement of TE Products Senior Notes

In January 2008, TE Products retired all of its outstanding debt by repaying at maturity $180.0 million principal amount of its 6.45% TE Products Senior Notes due 2008 and redeeming the remaining $175.0 million principal amount of its 7.51% TE Products Senior Notes due 2028. The redemption price for the 7.51% TE Products Senior Notes due 2028 was 103.755% of the principal amount plus accrued and unpaid interest to January 28, 2008, the date of redemption. We funded the retirement of the TE Products debt with borrowings under our Term Credit Agreement. For further information, please see Note 11 in the Notes to Unaudited Condensed Consolidated Financial Statements.

Future Capital Needs and Commitments

We estimate that capital expenditures, excluding acquisitions and joint venture contributions, for 2008 will be in the range of $310.0 million to $330.0 million (including approximately $14.0 million of capitalized interest). Excluding capitalized interest, we expect to spend in the range of $233.0 million to $253.0 million for revenue generating projects, which includes $133.0 million for our expected spending on the Motiva project. We expect to spend approximately $53.0 million to sustain existing operations (including $19.0 million for pipeline integrity) 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 $10.0 million to improve operational efficiencies and reduce costs among all of our business segments.

Additionally, we expect to invest approximately $132.0 million (including approximately $5.0 million of capitalized interest) in our Jonah joint venture during 2008 for the completion of the Phase V expansion and additional facilities to expand the Pinedale field production. We expect to invest approximately $42.0 million in 2008 as our net contribution to our Texas Offshore Port System joint venture for preliminary project costs.

During the remainder of 2008, TE Products may be required to contribute cash to Centennial to cover capital expenditures, debt service requirements or other operating needs. 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.

Liquidity Outlook

Our primary cash requirements consist of (i) ordinary course operating uses, such as operating expenses, capital expenditures to sustain existing operations, interest payments on our outstanding debt and distributions to our unitholders and General Partner, (ii) growth expenditures, such as capital expenditures for revenue generating activities (such as for Jonah and Texas Offshore Port System), and acquisitions of new assets or businesses and (iii) repayment of principal on our long-term debt. Our ordinary course operating cash requirements for 2008 are expected to be funded through our cash flows from operating activities. We expect cash requirements for growth expenditures and long-term debt repayments will be funded by a combination of several sources, including cash flows from operating activities, borrowings under credit facilities, joint venture distributions, the issuance of additional equity and debt securities, and the possible disposition of assets. See Note 11 in the Notes to Unaudited Condensed Consolidated Financial Statements.

Our ability to maintain adequate liquidity depends on our ability to have continued access to the financial markets and continue to generate cash from operations, both of which are subject to a number of factors, including prevailing market conditions, the possibility of a prolonged economic slowdown and general competitive, legislative, regulatory and other market factors that are beyond our control. See Item 1A, Part II. Risk Factors.

Recent volatility in the global capital markets has resulted in a significant increase in the costs of incremental debt and equity capital. We expect that the current cost of capital should trend lower in the coming months as coordinated government-led funding programs are implemented worldwide. As the capital markets begin to recover, we believe that we will have sufficient access to debt and equity capital to support our expected growth expenditures. In addition, we have the flexibility to reprioritize certain planned growth projects. Our disciplined approach to funding capital spending and other partnership needs, combined with sufficient trade credit to operate our businesses efficiently and available credit under our Revolving Credit Facility, should provide us with a solid foundation to meet our anticipated liquidity and capital resource requirements.

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 and the limited guarantee of Centennial catastrophic events as discussed below. In addition, we have entered into various operating leases covering assets utilized in several areas of our operations.

At September 30, 2008 and December 31, 2007, Centennial's debt obligations consisted of $132.5 million and $140.0 million, respectively, borrowed under a master shelf loan agreement. In January 2008, we entered into an amended and restated guaranty agreement ("Amended Guaranty") with Centennial's lenders, under which we, TE Products, TEPPCO Midstream and TCTM (collectively, the "TEPPCO Guarantors") are required, on a joint and several basis, to pay 50% of any past-due amount under Centennial's master shelf loan agreement not paid by Centennial. The Amended Guaranty also has a credit maintenance requirement whereby we may be required to provide additional credit support in the form of a letter of credit or pay certain fees if either of our credit ratings from

Standard & Poor's Ratings Group ("S&P") and Moody's Investors Service, Inc. ("Moody's") falls below investment grade levels as specified in the Amended Guaranty. If Centennial defaults on its debt obligations, the estimated maximum potential amount of future payments for the TEPPCO Guarantors and Marathon Petroleum Company LLC ("Marathon") is $66.2 million each at September 30, 2008. At September 30, 2008, we have a liability of $9.1 million, which is based upon the expected present value of amounts we would have to pay under the guarantee.

TE Products, Marathon and Centennial have also 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, at September 30, 2008, TE Products has a liability of $3.9 million, which is based upon the expected present value of amounts we would have to pay under the guarantee. If a catastrophic event were to occur and we were required to contribute cash to Centennial, such contributions might be covered by our insurance (net of deductible), depending upon the nature of the catastrophic event.

One of our subsidiaries, TCO, has entered into master equipment lease agreements with finance companies for the use of various pieces of equipment. Lease expense related to this equipment is approximately $5.2 million per year. 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. We do not believe that any performance under the guarantee would have a material effect on our financial condition, results of operations or cash flows.

Contractual Obligations

We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. Total rental expense included in operating costs and expenses was $4.6 million, $4.0 million, $15.2 million and $17.6 million for the three months and nine months ended September 30, 2008 and 2007, respectively. There have been no material changes in our operating lease commitments since December 31, 2007.

In March 2008, we issued $1.0 billion of senior notes due in 2013, 2018 and 2038 (see Note 11 in the Notes to Unaudited Condensed Consolidated Financial Statements). Other than the issuance of these senior notes and the expected contributions in 2008 to the Texas Offshore Port System joint venture discussed above, there have been no significant changes in our schedule of maturities of long-term debt or other contractual obligations since the year ended December 31, 2007.

The following table summarizes our debt repayment obligations as of September 30, 2008 (in thousands):

	Amount of Commitment Expiration Per Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Revolving Credit Facility, due 2012	$ 324,717	$ --	$ --	$ 324,717	$ --
7.625% Senior Notes due 2012 (1)	500,000	--	--	500,000	--
6.125% Senior Notes due 2013 (1)	200,000	--	--	200,000	--
5.90% Senior Notes, due 2013 (1)	250,000	--	--	250,000	--
6.65% Senior Notes, due 2018 (1)	350,000	--	--	--	350,000
7.55% Senior Notes, due 2038 (1)	400,000	--	--	--	400,000
7.00% Junior Subordinated Notes due 2067 (1)	300,000	--	--	--	300,000
Interest payments (2)	2,692,176	154,584	302,346	229,871	2,005,375
Total	$ 5,016,893	$ 154,584	$ 302,346	$ 1,504,588	$ 3,055,375

(1) At September 30, 2008, the 7.625% Senior Notes includes a deferred gain of $19.4 million, net of amortization, from interest rate swap terminations (see Note 5 in the Notes to Unaudited Condensed Consolidated Financial Statements). At September 30, 2008, our senior notes and our junior subordinated notes include an aggregate of $5.4 million of unamortized debt discounts. The deferred gain and the unamortized debt discounts are excluded from this table.

(2) Includes interest payments due on our senior notes and junior subordinated notes and interest payments and commitment fees due on our Revolving Credit Facility. The interest amounts calculated on the Revolving Credit Facility and the junior subordinated notes are based on the assumption that the amounts outstanding and the interest rates charged both remain at their current levels.

Summary of Related Party Transactions

The following table summarizes our revenue and expense transactions with related parties for the three months and nine months ended September 30, 2008 and 2007 (in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Revenues from EPCO and affiliates:				
Sales of petroleum products	$ 181	$ 91	$ 485	$ 196
Transportation – NGLs	3,391	3,478	10,182	9,493
Transportation – LPGs	1,392	695	4,691	2,968
Transportation – Refined products	--	61	--	105
Other operating revenues	1,077	301	2,302	1,508
Revenues from unconsolidated affiliates:				
Other operating revenues	22	216	66	325
Related party revenues	$ 6,063	$ 4,842	$ 17,726	$ 14,595
Costs and Expenses from EPCO and affiliates:				
Purchases of petroleum products	$ 51,443	$ 17,133	$ 101,668	$ 40,373
Operating expense	27,132	24,126	75,392	72,890
General and administrative	7,340	6,568	24,117	19,150
Costs and Expenses from unconsolidated affiliates:				
Purchases of petroleum products	1,845	2,341	5,387	2,341
Operating expense	1,122	2,701	5,023	6,363
Costs and Expenses from Cenac and affiliates:				
Operating expense	13,810	--	32,327	--
Related party expenses	$ 102,692	$ 52,869	$ 243,914	$ 141,117

For additional information regarding our related party transactions, see Note 14 in the Notes to Unaudited Condensed Consolidated Financial Statements.

Credit Ratings

Our debt securities are rated BBB- by S&P, Baa3 by Moody's and BBB- by Fitch Ratings, all with stable outlooks. Such ratings reflect only the view of the rating agency and should not be interpreted as a recommendation to buy, sell or hold our securities. These ratings may be revised or withdrawn at any time by the agencies at their discretion. Based upon the characteristics of the fixed/floating unsecured junior subordinated notes that we issued in May 2007, Moody's and S&P each assigned 50% equity treatment to these notes. Fitch Ratings assigned 75% equity treatment to these notes.

Recent Accounting Pronouncements

On January 1, 2008, we adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 157, *Fair Value Measurements*, that apply to financial assets and liabilities. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. See Note 5 in the Notes to Unaudited Condensed Consolidated Financial Statements for information regarding fair value disclosures pertaining to our financial assets and liabilities.

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

Item 3. ***Quantitative and Qualitative Disclosures About Market Risk.***

We are exposed to financial market risks, including changes in commodity prices and interest rates. We do not have foreign exchange risks. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to fair values of certain debt instruments and cash flows resulting from changes in applicable interest rates or commodity prices. 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 our General Partner. 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, 2007.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates, resulting in the realization of income or loss depending on the specific hedging criteria. When this occurs, we may enter into a new financial instrument to reestablish the hedge to which the closed instrument relates.

Commodity Risk Hedging Program

We seek to maintain a position that is substantially balanced between crude oil purchases and related sales and future delivery obligations. 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*, where permitted.

As part of our crude oil marketing business, we enter into financial instruments such as swaps and other hedging instruments. Generally, we elect hedge accounting where permitted under SFAS 133. The terms of these contracts are typically one year or less. The purpose of such hedging activity is to either balance our inventory position or lock in a profit margin. For financial instruments 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 affect earnings. For financial instruments 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.

At September 30, 2008, we had a limited number of commodity financial instruments that were accounted for as cash flow hedges. The majority of these contracts will expire during 2008, with the remainder expiring during 2009, and any amounts remaining in accumulated other comprehensive income will be recorded in net income upon the contract expiration. Gains and losses on these financial instruments 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. No ineffectiveness was recognized as of September 30, 2008. In addition, we had some commodity financial instruments that did not qualify for hedge accounting. These financial instruments had a minimal impact on our earnings. The fair value of the open positions at September 30, 2008 was a liability of $2.8 million.

The following table shows the effect of hypothetical price movements on the estimated fair value ("FV") of this portfolio at the dates indicated (in thousands):

Scenario	Resulting Classification	December 31, 2007	September 30, 2008	October 21, 2008
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (18,897)	$ (2,816)	$ 2,540
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(33,606)	(4,660)	1,227
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(4,188)	(972)	3,853

The fair value of the open positions was based upon both quoted market prices obtained from NYMEX and from other sources such as 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 applicable discount rate.

Interest Rate Risk Hedging Program

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

Interest Rate Swap Expirations and Terminations. In January 2006, we entered into interest rate swap agreements with a total notional value of $200.0 million to hedge our exposure to increases in the benchmark interest rate underlying our variable rate Revolving Credit Facility. Under the swap agreements, we paid a fixed rate of interest ranging from 4.67% to 4.695% and received a floating rate based on the three-month U.S. Dollar LIBOR rate. At December 31, 2007, the fair value of these interest rate swaps was an asset of $0.3 million. These interest rate swaps expired in January 2008.

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. This swap agreement, designated as a fair value hedge, had a notional value of $210.0 million and was set to mature in January 2028 to match the principal and maturity of the TE Products Senior Notes. During the three months and nine months ended September 30, 2007, we recognized reductions in interest expense of $0.1 million and $0.7 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. In September 2007, we terminated this swap agreement, resulting in a loss of $1.2 million. This loss was deferred as an adjustment to the carrying value of the 7.51% Senior Notes, and approximately $0.2 million of the loss was amortized to interest expense in 2007, with the remaining $1.0 million recognized in interest expense in January 2008 at the time the 7.51% Senior Notes were redeemed.

Treasury Locks. At times, we may use treasury lock financial instruments to hedge the underlying U.S. treasury rates related to anticipated debt incurrence. Gains or losses on the termination of such instruments are amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. Each of our treasury lock transactions was designated as a cash flow hedge under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted.

In 2007, we entered into treasury locks, accounted for as cash flow hedges, that extended through January 31, 2008 for a notional value totaling $600.0 million. At December 31, 2007, the fair value of the treasury locks was a liability of $25.3 million. In January 2008, these treasury locks were extended through April 30, 2008. In March 2008, these treasury locks were settled concurrently with the issuance of senior notes (see Note 11 in the Notes to Unaudited Condensed Consolidated Financial Statements). The settlement of the treasury locks resulted in losses of $52.1 million, and these losses were recorded in accumulated other comprehensive income. We recognized approximately $3.6 million of this loss in interest expense as a result of interest payments hedged under the treasury locks not occurring as forecasted. The remaining losses are being amortized using the effective interest method as increases to future interest expense over the terms of the forecasted interest payments, which range from five to ten years. Over the next twelve months, we expect to reclassify $5.7 million of accumulated other comprehensive loss that was generated by these treasury locks as an increase to interest expense. In the event of early extinguishment of these senior notes, any remaining unamortized losses would be recognized in the statement of consolidated income at the time of extinguishment.

Fair Value Information

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. See Note 5 in the Notes to Unaudited Condensed Consolidated Financial Statements for information regarding fair value disclosures pertaining to our financial assets and liabilities.

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 the end of the period covered by this Report, 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

Other than as discussed under "TEPPCO Marine Services Transactions" below, there has been no change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) during the third quarter of 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

TEPPCO Marine Services Transactions

On February 1, 2008, we acquired transportation assets and certain intangible assets that comprised the marine transportation business of Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. (collectively, “Cenac”), the sole owner of Cenac Towing Co., Inc. and Cenac Offshore, L.L.C. On February 29, 2008, we purchased marine assets from Horizon Maritime, L.L.C. (“Horizon”), a privately-held Houston-based company and an affiliate of Mr. Cenac. These purchases were recorded using purchase accounting. In recording the TEPPCO Marine Services purchase transactions, we followed our normal accounting procedures and internal controls.

The Office of the Chief Accountant of the SEC has issued guidance regarding the reporting of internal control over financial reporting in connection with a material acquisition. This guidance was reiterated in September 2007 to affirm that management may omit an assessment of an acquired business’ internal control over financial reporting from management’s assessment of internal control over financial reporting for a period not to exceed one year.

We plan to exclude the operations acquired from Cenac and Horizon from the scope of our Sarbanes-Oxley Section 404 report on internal control over financial reporting for the year ended December 31, 2008. We are in the process of implementing our internal control structure over the operations we acquired from Cenac and Horizon. We expect this effort to be completed in late 2008 or early 2009.

The certifications of our General Partner’s CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this Report.

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. See discussion of legal proceedings in Note 16 in the Notes to Unaudited Condensed Consolidated Financial Statements under the headings “– Litigation” and “– Regulatory Matters,” which is incorporated into this item by reference.

Item 1A. *Risk Factors.*

Security holders and potential investors in our securities should carefully consider the risk factors set forth below and the risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2007, and in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 in addition to other information in such Reports and this Report. We have identified 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 us or on our behalf.

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 offshore and marine transportation and terminaling of refined products, LPGs, NGLs, petrochemicals and crude oil and in the gathering, compressing, and treating of natural gas, including ruptures, leaks, fires, spills, severe weather and other disasters. 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.

EPCO maintains insurance coverage on land-based and marine operations on our behalf, although insurance will not cover many types of hazards that might occur, including certain environmental accidents, and if covered we may still have responsibility for any applicable deductibles. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. For example, changes in the insurance markets resulting from the terrorist attacks on September 11, 2001 and the hurricanes of 2005 made it more difficult for us to obtain certain types of coverage. Hurricanes occurring in 2008 and the recent global financial crisis may negatively impact insurance carriers and affect our ability to obtain coverage. As a result, EPCO may not be able to renew existing insurance policies on our behalf or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

Our Texas Offshore Port System joint venture is subject to various business, operational and regulatory risks and may not be successful.

The Texas Offshore Port System joint venture is expected to represent an important component of our Upstream Segment, requiring an estimated $600.0 million in capital contributions from us through 2011. We and each of the other joint venture partners own a one-third interest in the joint venture, and a subsidiary of Enterprise Products Partners acts as construction manager and will act as operator. Accordingly, we will not have full control over the ongoing operational decisions. If we were unable to make a required capital contribution in Texas Offshore Port System, whether due to our inability to access capital markets or otherwise, our interest could be diluted, and we could suffer other adverse consequences. Further, if we or one of our joint venture partners were unable to make required contributions, the other partners may need to raise and contribute capital above their estimated share in order to complete the project, which capital may not be accessible on economical terms.

A variety of factors outside our control, such as weather, natural disasters, the fluctuating costs of steel and other raw materials and difficulties or inabilities in obtaining rights-of-way, permits or other regulatory approvals, as well as performance by third-party contractors, may result in increased costs or delays in construction. The offshore terminal will require approval by the U.S. Coast Guard and issuance of a Deepwater Port License, while the onshore pipeline and storage facilities will be subject to review by the U.S. Environmental Protection Agency, Army Corps of Engineers and Department of Transportation. Obtaining such approvals is a time consuming process; for example, we estimate that the Deepwater Port License could take two years to obtain without delays. The joint venture is also subject to various hazards inherent in the construction and operation of an offshore crude oil port and pipeline system, including damage to the ports, pipelines and related facilities caused by hurricanes and other inclement weather, inadvertent damage from third parties, leaks, operator error, litigation, environmental pollution and risk related to operating in a marine environment. Cost overruns, construction delays or other hazards inherent in the construction and operation of such a facility, whatever the cause, could have a material adverse effect on the success of the our joint venture project or on our business, results of operations, financial condition and prospects.

The current challenges in the credit markets may have impacts on our business and financial condition that we currently cannot predict.

The current challenges in the credit markets have had, and may continue to have, an impact on our business and our financial condition. We may face significant challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be severely restricted at a time when we would like, or need, to do so, which could have an adverse impact on our ability to meet our capital commitments and flexibility to react to changing economic and business conditions. In addition to Lehman, the credit crisis could have a negative impact on our remaining lenders or our customers, causing them to fail to meet their obligations to us. Additionally, our business depends on activity and expenditure levels in the energy industry, which are directly correlated to energy prices. Any of these factors could lead to reduced usage of our pipelines and energy logistics services, which could have a material negative impact on our revenues and prospects.

Item 5. *Other Information.*

Amendment to Partnership Agreement

On November 6, 2008, our General Partner amended our agreement of limited partnership to amend Section 6.7(i) to clarify and to provide that any amendment of Section 6.7 shall not impair an indemnitee's right to receive expense advancement, in addition to indemnification, from us otherwise provided for under the partnership agreement. In addition, the member of Texas Eastern Products Pipeline Company, LLC, our General Partner, amended its limited liability company agreement to make a similar change.

A copy of the amendments to our partnership agreement and the General Partner's limited liability company agreement are attached hereto as Exhibit 3.5 and Exhibit 3.6, respectively, and are incorporated by reference herein.

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	Fourth Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P., dated December 8, 2006 (Filed as Exhibit 3 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on December 13, 2006).
3.3	Amended and Restated Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC (Filed as Exhibit 3 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 10, 2007 and incorporated herein by reference).
3.4	First Amendment to Fourth Amended and Restated Partnership Agreement of TEPPCO Partners, L.P. dated as of December 27, 2007 (Filed as Exhibit 3.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed December 28, 2007 and incorporated herein by reference).
3.5*	Amendment No. 2 to the Fourth Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P. dated as of November 6, 2008.
3.6*	First Amendment to the Amended and Restated Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated as of November 6, 2008.
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	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).
4.3	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).
4.4	Second Supplemental Indenture, dated as of September 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 September 30, 2002 and incorporated herein by reference).
4.5	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).
4.6	Full Release of Guarantee dated as of July 31, 2006 by Wachovia Bank, National Association, as trustee, in favor of Jonah Gas Gathering Company (Filed as Exhibit 4.8 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2006 and incorporated herein by reference).
4.7	Indenture, dated as of May 14, 2007, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as subsidiary guarantors, and The Bank of New York Trust Company, N.A., as trustee (Filed as Exhibit 99.1 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 15, 2007 and incorporated herein by reference).
4.8	First Supplemental Indenture, dated as of May 18, 2007, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as subsidiary guarantors, and The Bank of New York Trust Company, N.A., as trustee (Filed as Exhibit 4.2 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 18, 2007 and incorporated herein by reference).
4.9	Second Supplemental Indenture, dated as of September 30, 2007, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. , Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as subsidiary guarantors, and The Bank of New York Trust Company, N.A., as trustee (Filed as Exhibit 4.2 to the Current Report on Form 8-K of TE Products Pipeline Company, LLC (Commission File No. 1-13603) filed on July 6, 2007 and incorporated herein by reference).
4.10	Fourth Supplemental Indenture, dated as of September 30, 2007, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as subsidiary guarantors, and U.S. Bank National Association, as trustee (Filed as Exhibit 4.3 to the Current Report on Form 8-K of TE Products Pipeline Company, LLC (Commission File No. 1-13603) filed on July 6, 2007 and incorporated herein by reference).
4.11	Fifth Supplemental Indenture, dated as of March 27, 2008, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC, and Val Verde Gathering Company, L.P., as subsidiary guarantors, and U.S. Bank National Association, as trustee (Filed as Exhibit 4.11 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2008 and incorporated herein by reference).
4.12	Sixth Supplemental Indenture, dated as of March 27, 2008, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as subsidiary guarantors, and U.S. Bank National Association, as trustee (Filed as Exhibit 4.12 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2008 and incorporated herein by reference).
4.13	Seventh Supplemental Indenture, dated as of March 27, 2008, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as subsidiary guarantors, and U.S. Bank National Association, as trustee (Filed as Exhibit 4.13 to Form

	10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2008 and incorporated herein by reference).
10.1	Sixth Amendment to Amended and Restated Credit Agreement, dated as of July 1, 2008, by and among TEPPCO Partners, L.P., the Borrower, the several banks and other financial institutions party thereto and SunTrust Bank, as the Administrative Agent for the Lenders (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2008 and incorporated herein by reference).
10.2*	Supplement and Joinder Agreement dated as of July 17, 2008 of the Amended and Restated Credit Agreement dated as of October 21, 2005, among TEPPCO Partners, L.P., as Borrower, the banks and other financial institutions party thereto and SunTrust Bank, as the Administrative Agent for the Lenders.
10.3	Partnership Agreement of Texas Offshore Port System, dated as of August 14, 2008 (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on August 20, 2008 and incorporated herein by reference).
10.4+	Unit Purchase Agreement dated September 4, 2008 by and between TEPPCO Unit L.P. and TEPPCO Partners, L.P. (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on September 9, 2008 and incorporated herein by reference).
10.5+	Agreement of Limited Partnership of TEPPCO Unit L.P., dated September 4, 2008 (Filed as Exhibit 10.2 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on September 9, 2008 and incorporated herein by reference).
10.6+*	Form of Distribution Equivalent Rights Grant of Texas Eastern Products Pipeline Company, LLC, under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan.
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.

Date: November 7, 2008	By: /s/ JERRY E. THOMPSON Jerry E. Thompson, President and Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC, General Partner
Date: November 7, 2008	By: /s/ WILLIAM G. MANIAS William G. Manias, Vice President and Chief Financial Officer of Texas Eastern Products Pipeline Company, LLC, General Partner

Exhibit 3.5

AMENDMENT NO. 2
TO THE FOURTH AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP
OF
TEPPCO PARTNERS, L.P.

This Amendment No. 2 (this "*Amendment No. 2*") to the Fourth Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P. dated effective as of December 8, 2006 (as amended by Amendment No. 1 thereto adopted effective as of December 27, 2007, the "*Partnership Agreement*") is hereby adopted by Texas Eastern Products Pipeline Company, LLC, a Delaware limited liability company (the "*General Partner*"), as general partner of the Partnership. Capitalized terms used but not defined herein are used as defined in the Partnership Agreement.

WHEREAS, acting pursuant to the power and authority granted to it under Section 15.1(d) of the Partnership Agreement, the General Partner has determined that the following amendment to the Partnership Agreement does not require the approval of any Limited Partner.

NOW THEREFORE, the General Partner does hereby amend the Partnership Agreement as follows:

Section 1. Sections 6.7(i) is hereby amended to read in full as follows:

(i) No amendment, modification or repeal of this Section 6.7 or any provision hereof shall in any manner terminate, reduce or impair the right of any past, present or future Indemnitee to receive indemnification (including expense advancement as provided by Section 6.7(b)) from the Partnership, nor the obligation of the Partnership to indemnify, or advance the expenses of, any such Indemnitee under and in accordance with the provisions of this Section 6.7 as in effect immediately prior to such amendment, modification or repeal with respect to claims arising from or relating to matters occurring, in whole or in part, prior to such amendment, modification or repeal, regardless of when such claims may arise or be asserted.

Section 2. Except as hereby amended, the Partnership Agreement shall remain in full force and effect.

Section 3. This Amendment No. 2 shall be governed by, and interpreted in accordance with, the laws of the State of Delaware, all rights and remedies being governed by such laws without regard to principles of conflicts of laws.

IN WITNESS WHEREOF, this Amendment No. 2 has been executed as of November 6, 2008.

GENERAL PARTNER:

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC

By: /s/ Jerry E. Thompson
Jerry E. Thompson
President and Chief Executive Officer

Exhibit 3.6

FIRST AMENDMENT
TO THE
AMENDED AND RESTATED LIMITED LIABILITY COMPANY AGREEMENT
OF
TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC

This First Amendment dated November 6, 2008 to the Amended and Restated Limited Liability Company Agreement (this "Amendment") of Texas Eastern Products Pipeline Company, LLC ("TEPPCO GP"), dated May 7, 2007, is executed by Enterprise GP Holdings L.P. ("EPE"). Capitalized terms used but not defined in this Amendment shall have the meaning set forth in the Limited Liability Company Agreement of TEPPCO GP dated May 7, 2007 (the "LLC Agreement").

RECITALS

WHEREAS, EPE Holdings, LLC (the "Company") owns a 0.01% general partner interest in and is the sole general partner of EPE;

WHEREAS, EPE is the sole member of TEPPCO GP;

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

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

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

AGREEMENT

1. Section 6.06(i) of the LLC Agreement shall be deleted and restated in its entirety as follows:

(i) No amendment, modification or repeal of this Section 6.06 or any provision hereof shall in any manner terminate, reduce or impair either the right of any past, present or future Indemnitee to receive indemnification (including expense advancement as provided by Section 6.06(b)) from the Company or the obligation of the Company to indemnify, or advance the expenses of, any such Indemnitee under and in accordance with the provisions of this Section 6.06 as in effect immediately prior to such amendment, modification or repeal with respect to claims arising from or relating to matters occurring, in whole or in part, prior to such amendment, modification or repeal, regardless of when such claims may arise or be asserted, and provided such Person became an Indemnitee hereunder prior to such amendment, modification or repeal.

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

[*Signature Page Follows*]

IN WITNESS WHEREOF, the undersigned has executed this Amendment to Limited Liability Company Agreement as of November 6, 2008.

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

By: EPE Holdings, LLC, its general partner

By: /s/ W. Randall Fowler
Name: W. Randall Fowler
Title: Executive Vice President and Chief Financial Officer

SUPPLEMENT AND JOINDER AGREEMENT

THIS SUPPLEMENT AND JOINDER AGREEMENT (this "Agreement") dated as of July 17, 2008, is being executed and delivered pursuant to the provisions of Section 2.6 of that certain Amended and Restated Credit Agreement dated as of October 21, 2004, among TEPPCO PARTNERS, L.P., as Borrower, the Lenders from time to time parties thereto, and SUNTRUST BANK, as Administrative Agent for the Lenders (as the same has been, and may hereafter be, amended, restated and supplemented from time to time, the "Credit Agreement"), by each of the existing Lenders listed on the signature pages hereto (each a "Consenting Lender" and collectively the "Consenting Lenders"), by each of the banks and other lenders listed on the signature pages hereto that was not, prior to the date hereof, a Lender under the Credit Agreement (each an "Additional Lender" and collectively the "Additional Lenders"), and the Borrower, and accepted by the Administrative Agent. Capitalized terms used herein and not otherwise defined herein shall have the meanings assigned to such terms in the Credit Agreement.

BACKGROUND

A. Pursuant to Section 2.6 of the Credit Agreement, the Borrower has notified the Administrative Agent and each of the Lenders that the Borrower proposes to increase the Aggregate Commitment Amount under the Credit Agreement to the total amount of $950,000,000.

B. Each of the Consenting Lenders has agreed to increase its Commitment by the amount specified for such Consenting Lender on Schedule I attached to this Agreement, and each of the Additional Lenders has agreed to extend to the Borrower a new Commitment in the amount specified for such Additional Lender on such Schedule I and to become an additional Lender for all purposes of the Credit Agreement.

C. The parties to this Agreement are entering into this Agreement for purposes of effecting the increase in the Commitments of the Consenting Lenders and the extension of the new Commitments of the Additional Lenders, all as contemplated by Section 2.6 of the Credit Agreement.

Accordingly, each of the parties to this Agreement hereby agrees as follows:

1. Each of the Consenting Lenders hereby agrees to increase the amount of its Commitment to the Borrower under the Credit Agreement by the respective amount for such Consenting Lender shown as being its "Increase in Commitment" on Schedule I attached to this Agreement. Such increase shall take effect for all purposes of the Credit Agreement on the Effective Date (as hereinafter defined) of this Agreement.

2. Each of the Additional Lenders hereby extends to the Borrower, subject to and on the terms and conditions set forth in the Credit Agreement, a Commitment in the amount shown for such Additional Lender as its "Additional Commitment" on Schedule I attached to this Agreement, from and after the Effective Date of this Agreement, and agrees to perform in accordance with the terms thereof all of the obligations which by the terms of the Credit

Agreement and the other Credit Documents are required to be performed by it as a Lender thereunder. Each Additional Lender represents and warrants that (i) it has full power and authority, and has taken all action necessary, to execute and deliver this Agreement and to consummate the transactions contemplated hereby and to become a Lender under the Credit Agreement, (ii) from and after the Effective Date of this Agreement, it shall be bound by the provisions of the Credit Agreement as a Lender thereunder and shall have and perform all of the obligations of a Lender thereunder, and (iii) it has received a copy of the Credit Agreement, together with copies of the most recent financial statements delivered pursuant to Section 8.1 of the Credit Agreement, as applicable, and such other documents and information as it has deemed appropriate to make its own credit analysis and decision to enter into this Agreement and to extend the Commitment to the Borrower pursuant to the terms of the Credit Agreement, on the basis of which it has made such analysis and decision independently and without reliance on the Administrative Agent or any other Lender. Each Additional Lender agrees that it will, independently and without reliance on the Administrative Agent or any other Lender, and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions and analysis in taking or not taking action under the Credit Agreement or any other Credit Documents. Each Additional Lender has submitted, or shall promptly hereafter submit, to the Administrative Agent an administrative questionnaire duly completed by such Additional Lender to be used and relied upon by the Administrative Agent for all purposes of the Credit Agreement.

3. Each party hereto acknowledges and agrees that the respective Commitments of the Additional Lenders, the Consenting Lenders, and the other Lenders under the Credit Agreement are several and not joint commitments and obligations of such Lenders. After giving effect to the additional and increased Commitments as provided in this Agreement, each party further acknowledges and agrees that upon the funding of any additional Borrowings on or after the Effective Date, the outstanding principal amounts of all Commitments and the respective Percentages of the Lenders are those set forth on Schedule II.

4. Each party hereto agrees that this Agreement and the effectiveness of the additional and increased Commitments as provided in this Agreement shall be subject to satisfaction by the Borrower of the following conditions and requirements:

(a) The Borrower shall have delivered to the Administrative Agent the following in form and substance satisfactory to the Administrative Agent:

(i) a counterpart of this Agreement signed by the Consenting Lenders, the Additional Lenders, the Borrower and the Administrative Agent;

(ii) a duly executed Note payable to each Consenting Lender and Additional Lender to the extent requested by any such Lender;

(iii) a certificate of the Secretary or Assistant Secretary of the General Partner of the Borrower, attaching and certifying copies of the authorizing resolutions for the additional and increased Commitments and any Borrowings thereunder as provided in this Agreement; and

(iv) the favorable written opinions of Bracewell & Giuliani LLP and Patricia A. Totten, each as counsel to the Borrower, addressed to the Administrative Agent and each of the Lenders, and covering such matters relating to the Borrower and this Agreement and the transactions contemplated herein as the Administrative Agent shall reasonably request.

(b) The Borrower shall have paid to the Administrative Agent (i) all costs and expenses incurred by the Administrative Agent in connection with this Supplement and Joinder Agreement and the transactions contemplated herein, including without limitation, all reasonable fees and expenses of counsel for the Administrative Agent, and (ii) for the account of each Consenting Lender and Additional Lender, an upfront fee in an amount equal to 0.20% of such Consenting Lender's Increase in Commitment, and 0.20% of such Additional Lender's Additional Commitment, in each case as shown on <u>Schedule I</u> to this Agreement.

The date on which the foregoing conditions have been satisfied shall be the "<u>Effective Date</u>" of this Agreement.

5. The Borrower represents and warrants to the Administrative Agent and the Lenders as of the Effective Date that (i) this Agreement has been duly authorized, executed and delivered by the Borrower, (ii) the Credit Agreement, as supplemented hereby, constitutes the legal, valid and binding obligation of the Borrower enforceable against the Borrower in accordance with its terms except as may be limited by applicable bankruptcy, insolvency, reorganization, moratorium, or similar laws affecting the enforcement of creditors' rights generally and by general principles of equity, (iii) no Default or Event of Default exists, (iv) all representations and warranties of the Borrower set forth in the Credit Agreement are true and correct in all material respects on such date (or, if any such representation or warranty is expressly stated to have been made as of a specific date, as of such specific date), and (v) since the date of the most recent financial statements of the Borrower delivered to the Lenders pursuant to Section 8.1 of the Credit Agreement, there has been no change which has resulted in, or could reasonably be expected to result in, a Material Adverse Event.

6. Except as supplemented hereby, the Credit Agreement and all other documents executed in connection therewith shall remain in full force and effect, The Credit Agreement, as supplemented hereby, and all rights, powers and obligations created thereby or thereunder and under the Credit Documents and all such other documents executed in connection therewith are in all respects ratified and confirmed.

7. This Agreement may be executed in multiple counterparts, each of which shall constitute an original but all of which when taken together shall constitute one contract. Signature pages may be detached from multiple separate counterparts and attached to a single counterpart so that all signature pages are attached to the same document. Delivery of an executed counterpart by facsimile or other electronic means shall be effective as delivery of a manually executed counterpart of this Agreement. This Agreement, together with the applicable provisions of the Credit Agreement, constitutes the entire agreement among the parties hereto regarding the subject matter hereof and supersedes all prior agreements and understandings, oral or written, regarding such subject matter.

8. THIS AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK.

IN WITNESS WHEREOF, the Consenting Lenders, the Additional Lenders, and the Borrower have caused this Agreement to be duly executed and delivered by their respective authorized officers and representatives, and the Administrative Agent, for the benefit of the Additional Lenders, the Consenting Lenders. and all other Lenders under the Credit Agreement, has caused the same to be accepted by its authorized officer, as of the day and year first above written.

SUNTRUST BANK,
as a Consenting Lender

By: /s/ David Edge
Name: **David Edge**
Title: **Managing Director**

[SIGNATURE PAGE TO SUPPLEMENT AND JOINDER AGREEMENT]

WACHOVIA BANK, NATIONAL ASSOCIATION,
as a Consenting Lender

By: /s/ Shannon Townsend
Name: **Shannon Townsend**
Title: **Director**

[SIGNATURE PAGE TO SUPPLEMENT AND JOINDER AGREEMENT]

JPMORGAN CHASE BANK, N.A.,
as a Consenting Lender

By: /s/ Jennifer Fitzgerald
Name: **Jennifer Fitzgerald**
Title: **Associate**

[SIGNATURE PAGE TO SUPPLEMENT AND JOINDER AGREEMENT]

BNP PARIBAS,
as a Consenting Lender

By: /s/ Gregory E. George
Name: **GREGORY E. GEORGE**
Title: **Managing Director**

/s/ Greg Smothers
GREG SMOTHERS
DIRECTOR

[SIGNATURE PAGE TO SUPPLEMENT AND JOINDER AGREEMENT]

THE ROYAL BANK OF SCOTLAND plc
as a Consenting Lender

By: /s/ Brian D. Williams
Name: **Brian D. Williams**
Title: **Vice President**

[SIGNATURE PAGE TO SUPPLEMENT AND JOINDER AGREEMENT]

UBS LOAN FINANCE LLC,
as a Consenting Lender

By:	/s/ Richard L. Tavrow	/s/ David B. Julle
Name:	**Richard L. Tavrow**	**David B. Julle**
Title:	**Director Banking Products Services, US**	**Associate Director Banking Products Services, US**

[SIGNATURE PAGE TO SUPPLEMENT AND JOINDER AGREEMENT]

UNION BANK OF CALIFORNIA, N.A.,
as a Consenting Lender

By: /s/ Daniel A. Davis
Name: **Daniel A. Davis**
Title: **Vice President**

[SIGNATURE PAGE TO SUPPLEMENT AND JOINDER AGREEMENT]

WELLS FARGO BANK, N.A.,
as a Consenting Lender

By: /s/ Terrence D'Souza
Name: **Terence D'Souza**
Title: **Vice President**

[SIGNATURE PAGE TO SUPPLEMENT AND JOINDER AGREEMENT]

DnB NOR BANK ASA,
As an additional Lender

By: /s/ Thomas Tangen
Name: **Thomas Tangen**
Title: **First Vice President**

By: /s/ Kristin Riise
Name: **Kristin Riise**
Title: **Vice President**

[SIGNATURE PAGE TO SUPPLEMENT AND JOINDER AGREEMENT]

MIZUHO CORPORATE BANK (USA)
as an Additional Lender

By: /s/ Leun Mo
Name: **Leun Mo**
Title: **Senior Vice President**

[SIGNATURE PAGE TO SUPPLEMENT AND JOINDER AGREEMENT]

SUMITOMO MITSUI BANKING CORPORATION,
as an Additional Lender

By: /s/ Masakazu Hasegawa
Name: **Masakazu Hasegawa**
Title: **Joint General Manager**

[SIGNATURE PAGE TO SUPPLEMENT AND JOINDER AGREEMENT]

TEPPCO PARTNERS, L.P.,
as Borrower

By: TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC,
as General Partner

By: /s/ William G. Manias
Name: William G. Manias
Title: Vice President and Chief Financial Officer

ACCEPTED THIS 17th DAY OF JULY, 2008:

SUNTRUST BANK,
as Administrative Agent

By: /s/ David T. Edge
Name: **David Edge**
Title: **Managing Director**

[SIGNATURE PAGE TO SUPPLEMENT AND JOINDER AGREEMENT]

Schedule I

ADDITIONAL AND INCREASED COMMITMENTS

Consenting Lenders	Increases in Commitments
SunTrust Bank	$14,500,000
Wachovia Bank, National Association	14,500,000
JPMorgan Chase Bank, N.A.	14,000,000
BNP Paribas	14,000,000
The Royal Bank of Scotland plc	14,000,000
UBS Loan Finance LLC	5,000,000
Union Bank of California, N.A.	10,000,000
Wells Fargo Bank, NA	19,000,000

Additional Lenders	Additional Commitments
Mizuho Corporate Bank (USA)	$70,000,000
DnB Nor Bank ASA	50,000,000
Sumitomo Mitsui Banking Corporation	25,000,000

TOTAL INCREASES AND ADDITIONS: $250,000,000

Schedule II

LENDER COMMITMENTS AND PERCENTAGES*

Lenders	**Commitment Amounts**	**Percentages**
SunTrust Bank	$93,000,000	9.78947368%
Wachovia Bank, National Association	93,000,000	9.78947368%
JPMorgan Chase Bank, NA.	84,000,000	8.84210526%
BNP Paribas	82,000,000	8.63157895%
The Royal Bank of Scotland plc	82,000,000	8.63157895%
Wells Fargo Bank, NA	84,000,000	8.84210526%
KeyBank National Association	60,000,000	6.31578947%
Union Bank of California, N.A.	60,000,000	6.31578947%
Lehman Brothers Bank, FSB	38,500,000	4.05263158%
UBS Loan Finance LLC	43,500,000	4.57894737%
Citibank, N.A.	35,000,000	3.68421053%
The Bank of New York	35,000,000	3.68421053%
Bank of Communications, New York Branch	15,000,000	1.57894737%
DnB Nor Bank ASA	50,000,000	5.26315789%
Mizuho Corporate Bank (USA)	70,000,000	7.36842106%
Sumitomo Mitsui Banking Corporation	25,000,000	2.63157895%
TOTAL	**$950,000,000**	**100.00000000%**

*Upon the effectiveness of the Increases in Commitments and Additional Commitments as provided in the Supplement and Joinder Agreement

[SIGNATURE PAGE TO GUARANTORS' ACKNOWLEDGMENT AND AGREEMENT]

GUARANTORS' ACKNOWLEDGMENT AND AGREEMENT

Each of the undersigned Guarantors consents to the execution and delivery by the Borrower of the foregoing Supplement and Joinder Agreement and jointly and severally ratifies and confirms the terms of the Guaranty with respect to ail indebtedness now or hereafter outstanding under the Credit Agreement as supplemented hereby and all promissory notes issued thereunder. Each of the undersigned Guarantors acknowledges and agrees that, notwithstanding anything to the contrary contained herein or in any other document evidencing any indebtedness of the Borrower to the Lenders or any other obligation of the Borrower, or any actions now or hereafter taken by the Lenders with respect to any obligations of the Borrower, the Guaranty (i) is and shall continue to be an absolute, unconditional, joint and several, continuing and irrevocable guarantee of payment of all "*Guarantor Obligations*" to the extent and as provided therein, including without limitation, all Borrowings (including, without limitation, all Revolver Borrowings, Swingline Borrowings, and Term Borrowings) and Letters of Credit made and issued under the Credit Agreement, as supplemented hereby, and (ii) is and shall continue to be in full force and effect in accordance with its terms. Nothing contained herein to the contrary shall release, discharge, modify, change or affect the obligations or liabilities of any Guarantor under the Guaranty.

[Signature Page Follows]

VAL VERDE GAS GATHERING COMPANY, L.P.,
as Borrower

By: TEPPCO NGL Pipelines, LLC,
its sole General Partner

By: /s/ William G. Manias
Name: William G. Manias
Title: Vice President and
Chief Financial Officer

TCTM, L.P.,

By: TEPPCO GP, Inc.,
its sole General Partner

By: /s/ William G. Manias
Name: William G. Manias
Title: Vice President and
Chief Financial Officer

TEPPCO MIDSTREAM COMPANIES, LLC

By: TEPPCO GP, Inc.,
its sole Manager

By: /s/ William G. Manias
Name: William G. Manias
Title: Vice President and
Chief Financial Officer

TE PRODUCTS PIPELINE COMPANY, LLC

By: TEPPCO GP, Inc.,
its sole Manager

[SIGNATURE PAGE TO GUARANTORS' ACKNOWLEDGMENT AND AGREEMENT]

By: /s/ William G. Manias
Name: William G. Manias
Title: Vice President and
Chief Financial Officer

[SIGNATURE PAGE TO GUARANTORS' ACKNOWLEDGMENT AND AGREEMENT]

AMENDED AND RESTATED NOTE

$93,000,000 | July 17, 2008

FOR VALUE RECEIVED, **TEPPCO PARTNERS, L.P.**, a Delaware limited partnership (the "***Maker***"). promises to pay to the order of **SUNTRUST BANK** (the "***Payee***"), the principal amount of $93,000,000 or so much thereof as shall have been advanced by the Payee to the Maker pursuant to the Credit Agreement described below and shall from time to time be outstanding, together with interest on the unpaid amounts thereof from time to time outstanding.

This note is a "Note" under the Amended and Restated Credit Agreement, dated as of October 21, 2004 (as renewed, extended, amended, supplemented or restated, the "***Credit Agreement***"), among the Maker, the Payee, certain other Lenders from time to time parties thereto, and SunTrust Bank, as the Administrative Agent for the Lenders.

This note incorporates by reference the principal and interest payment terms in the Credit Agreement for this note, including, without limitation, the final maturity date for this note, which is the Stated Termination Date. Principal and interest are payable to the holder of this note by payment to the Administrative Agent at its offices at 303 Peachtree Street, N.E., 10th Floor, Atlanta, Georgia 30308 or at any other address of which the Administrative Agent may notify the Maker in writing.

This note also incorporates by reference all other provisions in the Credit Agreement applicable to this note including provisions for disbursement of principal, applicable interest rates before and after certain Events of Default, voluntary and mandatory prepayments, acceleration of maturity, exercise of Rights, payment of attorney's fees, courts costs and other costs of collection, certain waivers by the Maker and other obligors, assurances and security, choice of New York and United States federal law, usury savings and other matters applicable to the Credit Documents under the Credit Agreement.

This note is being delivered by the Maker and accepted by the Payee as a substitution and replacement for the revolving credit notes previously made by the Maker and delivered to the Payee evidencing the obligations under the Existing Credit Agreement and the Credit Agreement (the “Original Obligations”), but not as payment of such Original Obligations or as a novation with respect thereto.

TEPPCO PARTNERS, L.P., as the Maker

By: TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC,
as General Partner

By: /s/ William G. Manias
Name: William G. Manias
Title: Vice President and
Chief Financial Officer

[Signature Page for Amended and Restated Note]

Distribution Equivalent Rights
under the
EPCO Inc. 2006 TPP Long-Term Incentive Plan

Date of Grant: ____________________

Name of Grantee: ____________________

Number of DERs Granted: ____________________

DER Grant Number: DER06 - ____

EPCO, Inc. (the "Company") is pleased to inform you that you have been granted the number of DERs set forth above under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (the "Plan"). A DER is a contingent right to an amount of cash equal to all or part of the cash distributions made by TEPPCO Partners, L.P. (the "Partnership") with respect to a Common Unit during a specified period, subject to the forfeiture and non-transferability provisions and other terms and conditions set forth below in this Agreement. The terms of the grant are as follows:

1. The DERs granted hereby entitle the Grantee to payments in respect of such DERs related to cash distributions made by the Partnership as described in Section 2 below, but only with respect to such distributions payable on a record date prior to the earlier of (i) _____________________ or (ii) the date on which you are no longer employed by the Company or any Affiliate of the Company for any reason other than as a result of a Qualifying Termination, as provided in Section 4 below, (the earlier of (i) or (ii) above is hereinafter referred to as the "DER Expiration Date"). Upon the occurrence of the DER Expiration Date, the DERs shall automatically and immediately be forfeited and cancelled without payment on such date; provided that Grantee is entitled to receive payments pursuant to this DER grant with respect to distributions made by the Partnership after the DER Expiration Date, but based upon a record date prior the DER Expiration Date.

2. For each calendar quarter in the period beginning on the Date of Grant and ending upon the DER Expiration Date, you will receive a cash payment within such calendar quarter (on or about the time the Partnership pays its quarterly distributions) equal to the product of (i) the cash distributions paid during such calendar quarter (based on a record date prior to the DER Expiration Date) with respect to a Common Unit, if any, times (ii) the number of DERs subject to this grant.

3. None of the DERs are transferable (by operation of law or otherwise) by you, other than by will or the laws of descent and distribution. If, in the event of your divorce, legal separation or other dissolution of your marriage, your former spouse is awarded ownership of, or an interest in, all or part of the DERs granted hereby to you, the DERs shall automatically and immediately be forfeited and cancelled without payment on such date.

4. If your employment with the Company and its Affiliates is terminated due to your (i) death, (ii) being disabled and entitled to receive long-term disability benefits under the Company's long-term disability plan provided that such disability qualifies as a "disability" under Section 409A of the Internal Revenue Code of 1986, as amended ("Section 409A") or (iii) retirement with the approval of the Company on or after reaching age 60 (any of (i), (ii) or (iii) is referred to as a "Qualifying Termination"), the DERs shall continue to be paid until the fourth anniversary of the Date of Grant. For this purpose, if you cease to be an "active, full-time employee" as determined by the Company in its sole discretion, without regard to how your status is treated by the Company for any of its other compensation or benefit plans or programs, you will be deemed to have terminated employment with the Company and its Affiliates for purposes of this Agreement.

5. Nothing in this Agreement or in the Plan shall confer any right on you to continue as an employee of the Company or its Affiliates. Unless you have a separate written employment agreement with the Company or an Affiliate, you are, and shall continue to be, an "at will" employee.

6. To the extent that the payment of an amount pursuant to a DER results in the receipt of compensation by you with respect to which the Company or an Affiliate has a tax withholding obligation pursuant to applicable law, the Company will withhold or, unless you make other arrangements that are acceptable to the Company or such Affiliate, you must deliver to the Company or the Affiliate, such amount of money as the Company or the Affiliate may require to meet its tax withholding obligations under such applicable law.

7. Notwithstanding any other provision of this Agreement, the Company shall not be obligated to deliver to you any payment if counsel to the Company determines such delivery would violate any law or regulation of any governmental authority or agreement between the Company or the Partnership and any national securities exchange upon which the Common Units are listed or any policy of the Company or any Affiliate of the Company.

8. These DERs are subject to the terms of the Plan, which is hereby incorporated by reference as if set forth in its entirety herein, including, without limitation, the ability of the Committee, in its discretion, to amend your DER award without your approval. In the event of a conflict between the terms of this Agreement and the Plan, the Plan shall be the controlling document. Capitalized terms that are used, but are not defined, in this Award have the respective meanings provided for in the Plan.

EPCO, INC.

By:________________________________
[Name, Title]

Exhibit 12.1
Statement of Computation of Ratio of Earnings to Fixed Charges

	2004	2005	2006	2007	Nine Months Ended September 30, 2008
			(in thousands)		
Earnings					
Income From Continuing Operations *	112,658	138,639	158,538	132,701	98,535
Fixed Charges	80,695	93,414	101,905	119,603	125,155
Distributed Income of Equity Investment	47,213	37,085	63,483	122,900	119,017
Capitalized Interest	(4,227)	(6,759)	(10,681)	(11,030)	(14,177)
Total Earnings	236,339	262,379	313,245	364,174	328,530
Fixed Charges					
Interest Expense	72,053	81,861	86,171	101,223	105,906
Capitalized Interest	4,227	6,759	10,681	11,030	14,177
Rental Interest Factor	4,415	4,794	5,053	7,350	5,072
Total Fixed Charges	80,695	93,414	101,905	119,603	125,155
Ratio: Earnings / Fixed Charges	2.93	2.81	3.07	3.04	2.62

* Excludes discontinued operations, gain on sale of assets, provision for income taxes 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 (the registrant's fourth fiscal quarter in the case of an annual report) 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.

November 7, 2008 /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 (the registrant's fourth fiscal quarter in the case of an annual report) 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.

November 7, 2008

/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 September 30, 2008 (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

November 7, 2008

A signed original of this written statement required by Section 906 has been provided to TEPPCO Partners, L.P. and will be retained by TEPPCO Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

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

In connection with the Quarterly Report of TEPPCO Partners, L.P. (the “Company”) on Form 10-Q for the quarter ended September 30, 2008 (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

November 7, 2008

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.