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

FORM 10-K

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

For the fiscal year ended December 31, 2006

OR

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

For the transition period from __________ to __________.

Commission File Number 1-10403

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

Delaware **(State or 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)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Limited Partner Units representing Limited Partner Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None.**

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

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

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

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

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

At June 30, 2006, the aggregate market value of the registrant's Limited Partner Units held by non-affiliates was $2,378,923,338, which was computed using the average of the high and low sales prices of the Limited Partner Units on June 30, 2006.

Limited Partner Units outstanding as of February 27, 2007: 89,804,829.

Documents Incorporated by Reference: **None.**

TEPPCO PARTNERS, L.P.
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SIGNIFICANT RELATIONSHIPS REFERENCED IN THIS ANNUAL REPORT

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

References to "*General Partner*" mean Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and owned by a private company subsidiary of EPCO, Inc.

References to "*TE Products*," "*TCTM*" and "*TEPPCO Midstream*" mean TE Products Pipeline Company, Limited Partnership, TCTM, L.P., and TEPPCO Midstream Companies, L.P., our subsidiaries. Collectively, TE Products, TCTM and TEPPCO Midstream are referred to as the "*Operating Partnerships.*"

References to "*TEPPCO GP*" mean TEPPCO GP, Inc., our subsidiary, which is the general partner of the Operating Partnerships.

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

References to "*Enterprise Products GP*" mean Enterprise Products GP, LLC, which is the general partner of Enterprise.

References to "*Enterprise GP Holdings*" mean Enterprise GP Holdings L.P., which owns Enterprise Products GP.

References to "*EPE Holdings*" mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to "*EPCO*" mean EPCO, Inc., a privately-held company that indirectly owns the General Partner.

References to "*DFI*" mean DFI GP Holdings L.P., an affiliate of EPCO.

References to "*DEP*" mean Duncan Energy Partners L.P. and its consolidated subsidiaries, a publicly traded Delaware limited partnership, which is an affiliate of ours.

We, Enterprise, Enterprise Products GP, Enterprise GP Holdings, EPE Holdings, DEP and the General Partner are affiliates and under common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The matters discussed in this Annual Report on Form 10-K (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, plans, references to future success, references to intentions as to future matters and other such matters are forward-looking statements. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future *developments as well as other factors we believe are appropriate under the circumstances. While we believe our expectations reflected in these forward-looking statements are reasonable, whether actual results and developments will conform with our expectations and predictions is subject to a number of risks and uncertainties, including general economic, market or business conditions, the opportunities (or lack thereof) that may be presented to and pursued by us, competitive actions by other pipeline companies, changes in laws or regulations and other factors, many of which are beyond our control. For example, the demand for refined products is dependent upon the price, prevailing economic conditions and demographic changes in the markets served, trucking and railroad freight, agricultural usage and military usage; the demand for propane is sensitive to the weather and prevailing economic conditions; the demand for petrochemicals is dependent upon prices for products produced from petrochemicals; the demand for crude oil and petroleum products is dependent upon the price of crude oil and the products produced from the refining of crude oil; and the demand for natural gas is dependent upon the price of natural gas and the locations in which natural gas is drilled. We are also subject to regulatory factors such as the amounts we are allowed to charge our customers for the services we provide on our regulated pipeline systems. Consequently, all of the forward-looking statements made in this document are qualified by these cautionary statements, and we cannot assure you that actual results or developments that we anticipate will be realized or, even if substantially realized, will have the expected consequences to or effect on us or our business or operations. 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.*

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 Securities and Exchange Commission ("SEC"). In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Report may not occur.

PART I

Items 1 and 2. *Business and Properties*

General

We are a Delaware master limited partnership formed in March 1990. We are one of the largest common carrier pipelines of refined products and liquefied petroleum gases ("LPGs") in the United States. In addition, we own and operate petrochemical and natural gas liquids ("NGLs") pipelines; we are engaged in crude oil transportation, storage, gathering and marketing; we own and operate natural gas gathering systems; and we own interests in Seaway Crude Pipeline Company ("Seaway"), Centennial Pipeline LLC ("Centennial"), Mont Belvieu Storage Partners, L.P. ("MB Storage"), Jonah Gas Gathering Company ("Jonah") and an undivided ownership interest in the Basin Pipeline ("Basin"). We operate and report in three business segments:

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

Our reportable segments offer different products and services and are managed separately because each requires different business strategies. We operate through TE Products, TCTM and TEPPCO Midstream. Texas Eastern Products Pipeline Company, LLC, 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 the Operating Partnerships and TEPPCO GP holds a 0.001% general partner interest. Our interstate transportation operations, including rates charged to customers, are subject to regulation by the Federal Energy Regulatory Commission ("FERC"). In this Report, we refer to refined products, LPGs, petrochemicals, crude oil, lubrication oils and specialty chemicals, NGLs and natural gas, collectively as "*petroleum products*" or "*products*."

Dan L. Duncan and his affiliates, including EPCO, DFI, and Dan Duncan LLC, privately-held companies controlled by him, control us, our General Partner and Enterprise and its affiliates, including Enterprise GP Holdings and DEP. DFI owns all of the membership interests in our General Partner. Accordingly, DFI controls the 2% general partner interest in us and indirectly owns the incentive distribution rights associated with the general partner interest. In addition, DFI owns 2,500,000 of our limited partner units ("Units"), and the partners in DFI (or their parent companies) own 14,191,550 Units, representing a combined 18.6% interest in us.

We do not directly employ any officers or other persons responsible for managing our operations. Under an amended and restated administrative services agreement ("ASA"), EPCO performs all management, administrative and operating functions required for us, and we reimburse EPCO for all direct and indirect expenses that have been incurred in managing us. In February 2005, DFI acquired our General Partner for approximately $1.1 billion from a joint venture between ConocoPhillips and Duke Energy Corporation.

At December 31, 2006, 2005 and 2004, we had outstanding 89,804,829, 69,963,554 and 62,998,554 Units, respectively.

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

Business Strategy

Our business strategy is to grow TEPPCO's sustainable cash flow and to increase cash distributions to our unitholders. The key elements of our strategy are to:

- Focus on internal growth prospects in order to increase the pipeline system and terminal throughput, expand and upgrade existing assets and services and construct new pipelines, terminals and facilities;
- Target accretive and complementary acquisitions and expansion opportunities that provide attractive growth potential;
- Maintain a balanced mix of assets; and
- Operate in a safe, efficient, compliant and environmentally responsible manner.

We continue to build a base for long-term growth by pursuing new business opportunities, increasing throughput on our pipeline systems, constructing new pipeline and gathering systems, and expanding and upgrading our existing infrastructure. In 2006, our management performed a detailed analysis of our business environment and identified several key trends or factors that we believe will drive our growth opportunities in 2007 and beyond:

- We expect that Canadian crude oil imports to the U.S. will increase.
- We expect that crude oil imports to the U.S. Gulf Coast will increase.
- We expect that refined products imports to the U.S. will increase.
- We expect to see changes in commercial terminal ownership and operations.
- Standards for use of ethanol and other renewable fuels are currently mandated to double from 2005 to 2012; under federal legislation, renewable fuels will comprise increasing percentages of U.S. fuel supply, with a fuel standard of 7.5 billion gallons for such fuels set for 2012.
- We expect to see continued natural gas gathering and related service opportunities in the Jonah, Pinedale and San Juan Basin areas.

For a detailed discussion of these key trends or factors, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, "– Overview of Business."

Financial Information by Business Segment

See Note 15 in the Notes to the Consolidated Financial Statements for financial information by segment.

2006 Developments

Growth Projects, Acquisitions and Dispositions

In December 2006, we announced that we had signed an agreement with Motiva Enterprises, LLC ("Motiva") for us to construct and operate a new refined products storage facility to support the proposed expansion of Motiva's refinery in Port Arthur, Texas. Under the terms of the agreement, we will construct 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 3.5-mile product pipelines connecting the storage facility to Motiva's refinery, 15,000 horsepower of pumping capacity and distribution pipeline connections to the Colonial, Explorer and Magtex pipelines. For additional information, please see "– Downstream Segment – Transportation and Storage of Refined Products, LPGs and Petrochemicals."

In November 2006, we purchased a refined products terminal in Aberdeen, Mississippi, for approximately $5.8 million from Mississippi Terminal and Marketing Inc. ("MTMI"). The facility, located along the Tennessee-Tombigbee Waterway system, has storage capacity of 130,000 barrels for gasoline and diesel, which are supplied by barge for delivery to local markets, including Tupelo and Columbus, Mississippi. For additional information, please see "– Downstream Segment – Transportation and Storage of Refined Products, LPGs and Petrochemicals."

In July and December 2006, we purchased two active caverns, one active brine pond, a four bay truck rack, seven above ground storage tanks, and a twelve-spot railcar rack for $10.0 million and one active 170,000 barrel LPG storage cavern, the associated piping and related equipment for $4.8 million, respectively. For additional information, please see "– Downstream Segment – Transportation and Storage of Refined Products, LPGs and Petrochemicals."

On March 11, 2005, the Bureau of Competition of the Federal Trade Commission ("FTC") delivered written notice to DFI's legal advisor that it was conducting a non-public investigation to determine whether DFI's acquisition of our General Partner may substantially lessen competition or violate other provisions of federal antitrust laws. On October 31, 2006, an FTC order and consent agreement ending its investigation became final. The order requires the divestiture of our 50% interest in MB Storage and certain related assets to one or more FTC-approved buyers in a manner approved by the FTC and subject to its final approval. We expect to sell our interest in MB Storage and certain related pipelines during the first quarter of 2007. See Item 3. Legal Proceedings for further information.

Sale of Pioneer Silica Gel Plant

In March 2006, we sold our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise for $38.0 million in cash. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. For additional information, please see "– Midstream Segment – Gathering of Natural Gas, Transportation of NGLs and Fractionation of NGLs, Pioneer Plant."

Jonah Joint Venture

On August 1, 2006, Enterprise, through its affiliate, Enterprise Gas Processing, LLC, became our joint venture partner by acquiring an interest in Jonah, the general partnership through which we own an interest in the Jonah system.

We are in the fifth phase of our significant expansion of the Jonah system. In connection with the joint venture arrangement, we and Enterprise plan to continue the Phase V expansion, which is expected to increase the system capacity of the Jonah system from 1.5 Bcf/d to approximately 2.3 Bcf/d and to significantly reduce system operating pressures, which is anticipated to lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is in turn expected to increase the system gathering capacity to approximately 2.0 Bcf/d, is scheduled to be completed in the second quarter of 2007. The second portion of the expansion is expected to be completed by the end of 2007. The anticipated cost of the Phase V expansion is expected to be approximately $444.0 million. We expect to reimburse Enterprise for approximately 50% of these costs. To the extent the costs exceed an agreed upon base cost estimate of $415.2 million, we and Enterprise will each pay our respective ownership share (approximately 80% and 20%, respectively) of such costs. For additional information, please see "– Midstream Segment – Gathering of Natural Gas, Transportation of NGLs and Fractionation of NGLs."

Special Unitholder Meeting

On December 8, 2006, at a special meeting of our unitholders, the Fourth Amended and Restated Agreement of Limited Partnership (the "New Partnership Agreement"), which amends and restates the Third Amended and Restated Agreement of Limited Partnership in effect prior to the special meeting (the "Previous Partnership Agreement") was approved and became effective. The New Partnership Agreement contains the following amendments to the Previous Partnership Agreement, among others:

- changes to certain provisions that relate to distributions and capital contributions, including the reduction in the General Partner's incentive distribution rights from 50% to 25% ("IDR Reduction Amendment"), elimination of the General Partner's requirement to make capital contributions to us to maintain a 2% capital account, and adjustment of our minimum quarterly distribution and target distribution levels for entity-level taxes;
- changes to various voting percentage requirements, in most cases from 66 $^{2}/_{3}$% of outstanding Units to a majority of outstanding Units;
- a reduction in the percentage of holders of outstanding Units necessary to constitute a quorum from 66 $^{2}/_{3}$% to a majority of the outstanding Units;
- removal of provisions requiring unitholder approval for specified actions with respect to the Operating Partnerships;
- changes to supplement and revise certain provisions that relate to conflicts of interest and fiduciary duties; and
- changes to provide for certain registration rights of the General Partner and its affiliates (including with respect to the Units issued in respect of the IDR Reduction Amendment, as described below), for the maintenance of the separateness of us from any other person or entity and other miscellaneous matters.

References in this Report to our "Partnership Agreement" are to our partnership agreement (including, as applicable, the Previous Partnership Agreement or the New Partnership Agreement), as in effect from time to time. By approval of the various proposals at the special meeting, and upon effectiveness of the New Partnership Agreement, an agreement was effectuated whereby we issued 14,091,275 Units on December 8, 2006 to our General Partner as consideration for the IDR Reduction Amendment. The number of Units issued to our General Partner was based upon a predetermined formula that, based on the distribution rate and the number of Units outstanding at the time of the issuance, resulted in our General Partner's receiving cash distributions from the newly-issued Units and from its reduced maximum percentage interest in our quarterly distributions approximately equal to the cash distributions our General Partner would have received from its maximum percentage interest in our quarterly distributions without the IDR Reduction Amendment. Effective as of December 8, 2006, the General Partner distributed the newly issued Units to its member, which in turn caused them to be distributed to other affiliates of EPCO.

Public Offering

In July 2006, we issued and sold in an underwritten public offering 5,750,000 Units at a price to the public of $35.50 per Unit. The net proceeds from the offering, which totaled approximately $196.0 million, were used to reduce indebtedness under our revolving credit facility. For further information, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, "– Financial Condition and Liquidity."

Downstream Segment – Transportation and Storage of Refined Products, LPGs and Petrochemicals

We conduct business in our Downstream Segment through the following:

- TE Products;
- TEPPCO Terminals Company, L.P. ("TEPPCO Terminals"), which owns a refined products terminal and two-bay truck loading rack both connected to the mainline system, and TG Pipeline, L.P. ("TG Pipeline"), which owns a 90-mile pipeline and storage facilities;
- TEPPCO Terminaling and Marketing Company, LLC, ("TTMC") which provides refined products terminaling and marketing services and owns a refined products terminal in Aberdeen, Mississippi;
- a subsidiary which owns the northern portion of the Dean Pipeline ("Dean North");
- our 50% equity investment in Centennial; and
- our 50% equity investment in MB Storage.

Properties and Operations

Our Downstream Segment owns, operates or has investments in properties located in 14 states. The operations of the Downstream Segment consist of interstate transportation, storage and terminaling of refined products and LPGs; intrastate transportation of petrochemicals; distribution and marketing operations including terminaling services and other ancillary services. Other activities are related to the intrastate transportation of petrochemicals under a throughput and deficiency contract.

TE Products is one of the largest pipeline common carriers of refined products and LPGs in the United States. The Downstream Segment, primarily through TE Products, owns and operates an approximately 4,700-mile pipeline system (together with the receiving, storage and terminaling facilities mentioned below, the "Products Pipeline System") extending from southeast Texas through the central and midwestern United States to the northeastern United States. Effective November 1, 2006, we purchased a refined products terminal in Aberdeen, Mississippi, for approximately $5.8 million from MTMI. The facility, located along the Tennessee-Tombigbee waterway system, has storage capacity of 130,000 barrels for gasoline and diesel, which are supplied by barge for delivery to local markets, including Tupelo and Columbus, Mississippi. In connection with this acquisition, which we plan to integrate into our Downstream Segment, we plan to construct a new 500,000-barrel terminal in Boligee, Alabama, at a cost of approximately $20.0 million, on an 80-acre site which we are leasing from the Greene County Industrial Development Board under a 60-year agreement. The Boligee terminal site is located approximately two miles from Colonial Pipeline. The new terminal is expected to begin service during the fourth quarter of 2007.

As an interstate common carrier, our Products Pipeline System offers interstate transportation services, pursuant to tariffs filed with the FERC, to any shipper of refined products and LPGs who requests these services, provided that the conditions and specifications contained in the applicable tariff are satisfied. In addition to services for transportation of products, we also provide storage and other related services at key points along our Products Pipeline System. Substantially all of the refined products and LPGs transported and stored in our Products Pipeline System are owned by our customers. The products are received from refineries, connecting pipelines and bulk and marine terminals located principally on the southern end of the pipeline system. The U.S. Gulf Coast region is a significant supply source for our facilities and is a major hub for petroleum refining. The products are stored and scheduled into the pipeline in accordance with customer nominations and shipped to delivery terminals for ultimate delivery to the final distributor (including gas stations and retail propane distribution centers) or to other pipelines. Based on industry publications and data provided to us by customers, we believe refining capacity and product flow in the U.S. Gulf Coast region will increase over the next five years, which we expect will result in increased demand for transportation, storage and distribution facilities in that region. Pipelines are generally the lowest cost method for intermediate and long-haul overland transportation of refined products and LPGs.

Excluding the storage facilities of Centennial and MB Storage, the Products Pipeline System includes 35 storage facilities with an aggregate storage capacity of 21 million barrels of refined products and 6 million barrels of

LPGs, including storage capacity leased to outside parties. The Products Pipeline System makes deliveries to customers at 62 locations including 20 truck racks, rail car facilities and marine facilities that we own. Deliveries to other pipelines occur at various facilities owned by TE Products or by third parties. TE Products also owns one active marine receiving terminal at Providence, Rhode Island. This facility includes a 400,000-barrel refrigerated storage tank along with ship unloading and truck loading facilities. We operate the terminal and provide propane loading services to a customer. Our ability in the Downstream Segment to serve propane markets in the Northeast is enhanced by this terminal, which is not physically connected to the Products Pipeline System.

The following table lists the material properties and investments of and ownership percentages in our Downstream Segment assets as of December 31, 2006:

	Our Ownership
Refined products and LPGs pipelines and terminals	100%
Mont Belvieu, Texas, to Port Arthur, Texas, petrochemical pipelines	100%
Northern portion of Dean Pipeline	100%
Centennial (1)	50%
MB Storage (2)	50%

(1) Accounted for as an equity investment.

(2) Accounted for as an equity investment. We expect to sell our ownership interest in MB Storage during the first quarter of 2007.

Refined products and LPGs deliveries in MMBbls for the years ended December 31, 2006, 2005 and 2004, were as follows:

	For Year Ended December 31, 2006	2005	2004
Refined Products Deliveries: (1)			
Gasoline	94.9	92.4	89.3
Jet Fuels	25.5	25.4	25.6
Distillates (2)	44.9	42.9	37.5
Subtotal	165.3	160.7	152.4
LPGs Deliveries:			
Propane	36.5	35.6	34.3
Butanes (includes isobutane)	8.5	9.4	9.7
Subtotal	45.0	45.0	44.0
Petrochemical Deliveries (3)	21.6	25.4	25.5
Total Product Deliveries	231.9	231.1	221.9
Centennial Product Deliveries	44.8	50.6	41.2

(1) Includes volumes on terminals not connected to the mainline system.

(2) Primarily diesel fuel, heating oil and other middle distillates.

(3) Includes Dean North refinery grade propylene volumes and petrochemical volumes on pipelines between Mont Belvieu and Port Arthur, Texas.

Refined Products, LPGs and Petrochemical Pipeline Systems

The Products Pipeline System is comprised of a 20-inch diameter line extending in a generally northeasterly direction from Baytown, Texas (located approximately 30 miles east of Houston), to a point in southwest Ohio near Lebanon, Ohio and our Todhunter facility near Middleton, Ohio. The Products Pipeline System continues eastward from our Todhunter facility to Greensburg, Pennsylvania, at which point it branches into two segments, one ending in Selkirk, New York (near Albany), and the other ending at Marcus Hook, Pennsylvania (near Philadelphia). The Products Pipeline System east of our Todhunter facility and ending in Selkirk is an 8-inch diameter line, and the line starting at Greensburg and ending at Marcus Hook varies in diameter from 6 inches to 8 inches. A second line, which also originates at Baytown, is 16 inches in diameter until it reaches Beaumont, Texas, at which point it reduces to a 14-inch diameter line. This second line extends along the same path as the 20-inch diameter line to the Products Pipeline System's terminal in El Dorado, Arkansas, before continuing as a 16-inch diameter line to Seymour, Indiana.

The Products Pipeline System also includes a 14-inch diameter line from Seymour to Chicago, Illinois, and a 10-inch diameter line running from Lebanon to Lima, Ohio. This 10-inch diameter pipeline connects to the Buckeye Pipe Line Company system that serves, among others, markets in Michigan and eastern Ohio. The Products Pipeline System also has a 6-inch diameter pipeline connection to the Greater Cincinnati/Northern Kentucky International Airport.

In addition, the Products Pipeline System contains numerous lines, ranging in size from 6 inches to 20 inches in diameter, associated with the gathering and distribution system, extending from Baytown to Beaumont; Texas City to Baytown; Pasadena, Texas, to Baytown and Baytown to Mont Belvieu and an 8-inch diameter pipeline connection to the George Bush Intercontinental Airport terminal in Houston.

The Products Pipeline System also has smaller diameter lines that extend laterally from El Dorado to Helena, Arkansas, from Shreveport, Louisiana, to El Dorado and from McRae, Arkansas, to West Memphis, Arkansas. The line from El Dorado to Helena has a 10-inch diameter. The line from Shreveport to El Dorado varies in diameter from 8 inches to 10 inches. The line from McRae to West Memphis has a 12-inch diameter.

TE Products also owns three parallel 12-inch diameter common carrier petrochemical pipelines between Mont Belvieu and Port Arthur. Each of these pipelines is approximately 70 miles in length. The pipelines transport ethylene, propylene, natural gasoline and naphtha. We entered into a 20-year agreement in 2002 with a major petrochemical producer for guaranteed throughput commitments on these three pipelines. During the years ended December 31, 2006, 2005, and 2004, we recognized $12.5 million, $12.1 million and $12.0 million, respectively, of revenue under the throughput and deficiency contract.

Our Downstream Segment also includes the marketing of refined products through TTMC, which acquired a terminal in November 2006. The facility, located along the Tennessee-Tombigbee Waterway system in Aberdeen, Mississippi, has storage capacity of 130,000 barrels for gasoline and diesel, which are supplied by barge for delivery to local markets, including Tupelo and Columbus, Mississippi. In connection with this acquisition, which we plan to integrate into our Downstream Segment, we plan to construct a new 500,000-barrel terminal in Boligee, Alabama, at a cost of approximately $20.0 million, on an 80-acre site which we are leasing from the Greene County Industrial Development Board under a 60-year agreement. The Boligee terminal site is located approximately two miles from Colonial Pipeline. The new terminal is expected to begin service during the fourth quarter of 2007.

Our Downstream Segment also includes the operations of the northern portion of the Dean Pipeline, which transports refinery grade propylene ("RGP") from Mont Belvieu to Point Comfort. The northern portion of the Dean Pipeline consists of 138 miles of pipeline from Mont Belvieu to Point Comfort.

On July 14, 2006, we purchased assets from New York LP Gas Storage, Inc. for $10.0 million. The assets consist of two active caverns, one active brine pond, a four bay truck rack, seven above ground storage tanks, and a twelve-spot railcar rack located east of our Watkins Glen, New York facility.

On December 26, 2006, we purchased assets from Vectren Utility Holdings, Inc. for $4.8 million. The assets consist of one active 170,000 barrel LPG storage cavern, the associated piping and related equipment. These assets are located adjacent to our Todhunter facility near Middleton, Ohio and tie into our existing LPG pipeline.

On December 19, 2006, we announced that we had signed an agreement with Motiva for us to construct and operate a new refined products storage facility to support the proposed expansion of Motiva's refinery in Port Arthur, Texas. Under the terms of the agreement, we will construct 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 3.5-mile product pipelines connecting the storage facility to Motiva's refinery, 15,000 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 in mid-2009. As a part of a separate but complementary initiative, we will construct 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. This associated project 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 $240.0 million, including $20.0 million for the 11-mile, 20-inch pipeline. By providing access to several major outbound refined product pipeline systems, shippers should have enhanced flexibility and new transportation options. 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. If the cancellation were to occur in 2007, Motiva would also pay costs incurred to date plus a five percent cancellation fee, with the fee increasing to ten percent after 2007.

On November 1, 2006, we announced plans to construct a new 20-inch diameter lateral pipeline to connect our mainline system to the Enterprise and MB Storage facilities at Mont Belvieu, Texas, at a cost of approximately $8.6 million. The new connection, which provides delivery from Enterprise of propane into our system at full line flow rates, complements our current ability to source product from MB Storage. The new connection also offers the ability to deliver other liquid products such as butanes and natural gasoline from Enterprise's storage facilities into our system at reduced flow rates until enhancements can be made. The capability to deliver butanes and natural gasoline from MB Storage at full flow rates is not expected to be impacted. Construction of the new connection was completed and placed in service in December 2006. This new pipeline replaces a 10-mile, 18-inch segment of pipeline that we sold to an Enterprise affiliate on January 23, 2007 for approximately $8.0 million. This asset was part of our Downstream Segment and had a net book value of approximately $2.5 million.

Centennial Pipeline Equity Investment

TE Products owns a 50% ownership interest in Centennial and Marathon Petroleum Company LLC ("Marathon") owns the remaining 50% interest. Centennial, which commenced operations in April 2002, owns an interstate refined products pipeline extending from the upper Texas Gulf Coast to central Illinois. Centennial constructed a 74-mile, 24-inch diameter pipeline connecting TE Products' facility in Beaumont, Texas, with an existing 720-mile, 26-inch diameter pipeline extending from Longville, Louisiana, to Bourbon, Illinois. The Centennial pipeline intersects TE Products' existing mainline pipeline near Creal Springs, Illinois, where Centennial constructed a two million barrel refined products storage terminal. Marathon operates the mainline Centennial pipeline, and TE Products operates the Beaumont origination point and the Creal Springs terminal.

Through December 31, 2006, including the amount paid for the acquisition of an additional ownership interest in February 2003, TE Products has invested $107.3 million in Centennial. TE Products has not received any distributions from Centennial since its formation.

Mont Belvieu Storage Equity Investment

On January 1, 2003, TE Products and Louis Dreyfus Energy Services L.P. ("Louis Dreyfus") formed MB Storage, and each own a 50% ownership interest in MB Storage. MB Storage owns storage capacity at the Mont Belvieu fractionation and storage complex and a short haul transportation shuttle system that ties Mont Belvieu, Texas, to the upper Texas Gulf Coast energy marketplace. The Mont Belvieu fractionation and storage complex is the largest complex of its kind in the United States. MB Storage is a service-oriented, fee-based venture serving the fractionation, refining and petrochemical industries with substantial capacity and flexibility for the transportation, terminaling and storage of NGLs, LPGs and refined products. MB Storage receives revenue from the storage, receipt and delivery of product from refineries and fractionators to pipelines, refineries and petrochemical facilities on the upper Texas Gulf Coast. MB Storage has no commodity trading activity. TE Products operates the facilities for MB Storage. We expect to sell our interest in MB Storage and certain related pipelines during the first quarter of 2007 pursuant to an FTC order and consent agreement.

MB Storage has approximately 36 million barrels of LPGs storage capacity and approximately 7 million barrels of refined products storage capacity, including storage capacity leased to outside parties. MB Storage includes a short-haul transportation shuttle system, consisting of a complex system of pipelines and interconnects, that ties Mont Belvieu to nearly all of the refinery and petrochemical facilities on the upper Texas Gulf Coast. MB Storage also provides truck and rail car loading capability and includes a 400-acre parcel of property for future expansion. Total shuttle volumes for the three years ended December 31, 2006, 2005 and 2004, were 34.1 million barrels, 37.7 million barrels and 39.3 million barrels, respectively.

For the years ended December 31, 2006, 2005 and 2004, TE Products' sharing ratio in the earnings of MB Storage was 59.4%, 64.2% and 69.4%, respectively. During the years ended December 31, 2006, 2005 and 2004, TE Products received distributions of $12.9 million, $12.4 million and $10.3 million, respectively, from MB Storage. During the years ended December 31, 2006, 2005 and 2004, TE Products contributed $4.8 million, $5.6 million and $21.4 million, respectively, to MB Storage. The 2005 contribution includes a combination of non-cash asset transfers of $1.4 million and cash contributions of $4.2 million. The 2004 contribution includes $16.5 million for the acquisition of storage and pipeline assets in April 2004. The remaining contributions have been for capital expenditures.

Seasonality

The mix of products delivered by our Downstream Segment varies seasonally. Gasoline demand is generally stronger in the spring and summer months, and LPGs demand is generally stronger in the fall and winter months, including the demand for normal butane which is used for the blending of gasoline. Weather and economic conditions in the geographic areas served by our Products Pipeline System also affect the demand for, and the mix of, the products delivered. Because propane demand is generally sensitive to weather in the winter months, meaningful year-to-year variations of propane deliveries have occurred most recently in the first and fourth quarters of 2006 and will likely continue to occur.

Major Business Sector Markets and Related Factors

Our Products Pipeline System transports refined products from the upper Texas Gulf Coast, eastern Texas and southern Arkansas to the Central and Midwest regions of the United States with deliveries in Texas, Louisiana, Arkansas, Missouri, Illinois, Kentucky, Indiana and Ohio. At these points, refined products are delivered to terminals owned by TE Products, connecting pipelines and customer-owned terminals.

Our Products Pipeline System transports LPGs from the upper Texas Gulf Coast to the Central, Midwest and Northeast regions of the United States and is the only pipeline that transports LPGs from the upper Texas Gulf Coast to the Northeast. The Products Pipeline System east of our Todhunter facility near Middleton, Ohio, is devoted solely to the transportation of LPGs. Our Products Pipeline System also transports normal butane and isobutane in the Midwest and Northeast for use in the production of motor gasoline.

TTMC conducts distribution and marketing operations whereby we provide terminaling services for our throughput and exchange partners at our Aberdeen terminal. We also purchase refined products from our throughput partner and we in turn establish a margin by selling refined products for physical delivery through spot sales at the Aberdeen truck rack to independent wholesalers and retailers of refined products. These purchases and sales are generally contracted to occur on the same day.

For further discussion of refined products and LPGs sensitivity to market conditions and other factors that may affect our Downstream Segment, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, "– Overview of Business."

Our major operations in the Downstream Segment consist of the transportation, storage and terminaling of refined products and LPGs along our system. Product deliveries, in MMBbls on a regional basis, for the years ended December 31, 2006, 2005 and 2004, were as follows:

	For Year Ended December 31,		
	2006	2005	2004
Refined Products Deliveries:			
Central (1)	74.6	73.3	69.0
Midwest (2)	66.6	60.1	53.5
Ohio and Kentucky	24.1	27.3	29.9
Subtotal	165.3	160.7	152.4
LPGs Deliveries:			
Central, Midwest and Kentucky (1)(2)	28.5	26.3	27.0
Ohio and Northeast (3)	16.5	18.7	17.0
Subtotal	45.0	45.0	44.0
Petrochemical Deliveries (4)	21.6	25.4	25.5
Total Product Deliveries	231.9	231.1	221.9
Centennial Product Deliveries	44.8	50.6	41.2

(1) Arkansas, Louisiana, Missouri, Mississippi and Texas.

(2) Illinois and Indiana.

(3) New York and Pennsylvania.

(4) Includes Dean North RGP volumes and petrochemical volumes on pipelines between Mont Belvieu and Port Arthur, Texas.

Customers

Our customers for the transportation of refined products include major integrated oil companies, independent oil companies, the airline industry and wholesalers. End markets for these deliveries are primarily retail service stations, truck stops, railroads, agricultural enterprises, refineries and military and commercial jet fuel users. Propane customers include wholesalers and retailers who, in turn, sell to commercial, industrial, agricultural and residential heating customers, utilities who use propane as a back-up fuel source and petrochemical companies who use propane as a process feedstock. Refineries constitute our major customers for butane and isobutane, which are used as a blend stock for gasolines and as a feed stock for alkylation units, respectively. Our customers for the transportation of petrochemical feedstocks (natural gasoline and naphtha) and semi-finished chemical products (RGP, polymer grade propylene and ethylene) are primarily major chemical companies that consume these components in the production of plastics and a wide array of other commercial products. TTMC's customers include major integrated oil companies and wholesale marketers. Our Downstream Segment depends in large part on the level of demand for refined products and LPGs in the geographic locations that we serve and the ability and willingness of customers having access to the pipeline system to supply this demand.

At December 31, 2006, our Downstream Segment had approximately 125 customers. During the year ended December 31, 2006, total revenues (and percentage of total revenues) attributable to the top 10 customers were $143.5 million (47%), of which no single customer accounted for more than 10% of total Downstream Segment revenues. At December 31, 2005, our Downstream Segment had approximately 155 customers. During the year ended December 31, 2005, total revenues (and percentage of total revenues) attributable to the top 10 customers were $151.6 million (53%), of which Marathon accounted for approximately 14% of total Downstream Segment revenues. At December 31, 2004, our Downstream Segment had approximately 139 customers. During the year ended December 31, 2004, total revenues (and percentage of total revenues) attributable to the top 10 customers were $151.7 million (54%), of which Marathon accounted for approximately 17% of total Downstream Segment revenues. During each of the three years ended December 31, 2006, 2005 and 2004, no single customer of the Downstream Segment accounted for 10% or more of total consolidated revenues.

Competition

The Downstream Segment faces competition from numerous sources. Because pipelines are generally the lowest cost method for intermediate and long-haul overland movement of refined products and LPGs, the Products Pipeline System's most significant competitors (other than indigenous production in its markets) are pipelines in the areas where the Products Pipeline System delivers products. Competition among common carrier pipelines is based primarily on transportation charges, quality of customer service and proximity to end users. We believe our Downstream Segment is competitive with other pipelines serving the same markets; however, comparison of different pipelines is difficult due to varying product mix and operations.

Trucks, barges and railroads competitively deliver products in some of the areas served by the Products Pipeline System and TTMC. Trucking costs, however, render that mode of transportation less competitive for longer hauls or larger volumes. Barge transportation of refined products is generally more competitive with the Products Pipeline System at those locations that are in close proximity to major waterways. We face competition from rail and pipeline movements of LPGs from Canada and waterborne imports into terminals located along the upper East Coast. TTMC's competition in the area is from refineries that require significant truck transportation to deliver their product in the area TTMC serves. TTMC is able to receive product by barge which gives it a competitive advantage with respect to other terminaling and marketing businesses in the general area, which generally do not receive product by barge.

Upstream Segment – Gathering, Transportation, Marketing and Storage of Crude Oil

We conduct business in our Upstream Segment through the following:

- TCTM, our holding company for the Upstream Segment;
- TEPPCO Crude Pipeline, L.P. ("TCPL"), TEPPCO Crude Oil, L.P. ("TCO") and Lubrication Services, L.P. ("LSI"), wholly owned subsidiaries of TCTM; and
- our 50% equity investment in Seaway.

Properties and Operations

Our Upstream Segment gathers, transports, markets and stores crude oil, and distributes lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Our Upstream Segment uses its asset base to aggregate crude oil and provide transportation and related services to its customers. Our Upstream Segment purchases crude oil from various producers and operators at the wellhead and makes bulk purchases of crude oil at pipeline and terminal facilities and trading locations. The crude oil is purchased under contracts, the majority of which range in term from a thirty-day evergreen to one year. The crude oil is then sold to refiners and other customers. The Upstream Segment transports crude oil through proprietary gathering systems, common carrier pipelines, equity owned pipelines, trucking operations and third party pipelines. The Upstream Segment also exchanges various grades of crude oil and exchanges crude oil at different geographic locations, as appropriate, in order to maximize margins or meet contract delivery requirements. Certain of our crude oil pipeline assets, including pipeline sections within our Red River, South Texas and West Texas systems and Basin and Seaway, are in interstate common carrier service, and as such, we file tariffs with the FERC. Movement of product on these lines is available to any shipper who requests these services, provided that the conditions and specifications contained in the applicable tariff are satisfied.

The areas served by our gathering and transportation operations are geographically diverse, and the forces that affect the supply of the products gathered and transported vary by region. Crude oil prices and production levels affect the supply of these products. The demand for gathering and transportation is affected by the demand for crude oil by refineries, refinery supply companies and similar customers in the regions served by this business.

TCO purchases crude oil and establishes a margin by selling crude oil for physical delivery to third party users. These purchases and sales are generally contracted to occur in the same calendar month. We seek to maintain a balanced marketing position to minimize our exposure to price fluctuations occurring after the initial purchase. However, commodity price risks cannot be completely eliminated.

Product deliveries on TCPL's 100% owned pipeline systems, Basin and Seaway for the years ended December 31, 2006, 2005 and 2004, were as follows (in millions):

	For Year Ended December 31,		
	2006	2005	2004
Barrels Delivered:			
Crude oil transportation	91.5	94.7	101.5
Crude oil marketing	222.1	203.3	177.3
Crude oil terminaling	126.0	110.3	113.2
Lubricants and chemicals (total gallons)	14.4	14.8	14.0
Seaway Barrels Delivered:			
Long-haul	88.4	99.7	94.3
Short-haul	223.4	213.9	215.8

Properties

The following table describes the major crude oil pipelines and pipeline systems and the ownership percentages in our Upstream Segment as of December 31, 2006:

Crude Oil Pipeline	Our Ownership	Operator	Description (1)
Red River System	100%	TCPL	1,690 miles of small diameter pipeline; 1,491,000 barrels of storage – North Texas to South Oklahoma
South Texas System	100%	TCPL	1,150 miles of small diameter pipeline; 1,106,000 barrels of storage – South Central Texas to Houston, Texas area
West Texas System	100%	TCPL	360 miles of small diameter pipeline; 275,000 barrels of storage – connecting West Texas and Southeast New Mexico to TCPL's Midland, Texas terminal
Other crude oil assets	100%	TCPL	265 miles of small diameter pipeline; 295,000 barrels of storage – primarily in Texas and Oklahoma
Cushing Terminal	100%	TCPL	15 tanks with 1,875,000 barrels of storage in Cushing, Oklahoma
Midland Station	100%	TCPL	11 tanks with 980,000 barrels of storage in Midland, Texas
Seaway (2)	50% general partnership interest	TCPL	500-mile, 30-inch diameter pipeline; 6,836,000 barrels of storage – Texas Gulf Coast to Cushing, Oklahoma; 30-mile Texas City system
Basin	13% joint ownership	Plains All American Pipeline, L.P.	416-mile pipeline, 20 to 24 inches in diameter – Permian Basin (New Mexico and Texas) to Cushing, Oklahoma

(1) Small diameter of pipeline ranges from two inches to twelve inches.

(2) TCPL's participation in revenues and expenses of Seaway vary as described below in "*Seaway Crude Pipeline Equity Investment*."

Most of the Red River System crude oil is delivered to Cushing, Oklahoma, via third party pipelines, or to two local refineries. The crude oil on the South Texas System is delivered on a tariff basis to Houston area refineries and to Cushing. The West Texas Trunk System connects gathering systems to TCPL's Midland, Texas, terminal.

Seaway Crude Pipeline Equity Investment

Seaway is a partnership between TEPPCO Seaway, L.P. ("TEPPCO Seaway"), a subsidiary of TCTM, and subsidiaries of ConocoPhillips. We operate the Seaway assets. Three large diameter lines carry crude oil from the Freeport, Texas, marine terminal on the U.S. Gulf Coast to the adjacent Jones Creek Tank Farm, which has six tanks capable of storing approximately 2.6 million barrels of crude oil. The 30-inch diameter, 500-mile pipeline transports crude oil from Freeport to Cushing, a central crude distribution point for the central United States and a delivery point for the New York Mercantile Exchange ("NYMEX").

The Seaway crude oil marine terminal facility at Texas City, Texas, is used to supply refineries in the Houston area. Two pipelines connect the Texas City marine terminal to storage facilities in Texas City and Galena Park, Texas, where there are nine tanks with a combined capacity of approximately 4.2 million barrels. Seaway has the capability to provide marine terminaling and crude oil storage services for all Houston area refineries.

The Seaway partnership agreement provides for varying participation ratios throughout the life of Seaway. From June 2002 through December 31, 2005, we received 60% of revenue and expense of Seaway. The sharing ratio changed from 60% to 40% on May 12, 2006, and as such, our share of revenue and expense of Seaway was 47% for 2006. Thereafter, we will receive 40% of revenue and expense of Seaway. During the years ended December 31, 2006, 2005 and 2004, we received distributions from Seaway of $20.5 million, $24.7 million and $36.9 million, respectively.

Line Transfers, Pumpovers and Other

Our Upstream Segment provides trade documentation services to its customers, primarily at Cushing and Midland. TCPL documents the transfer of crude oil in its terminal facilities between contracting buyers and sellers. This line transfer documentation service is related to the trading activity by TCPL's customers of NYMEX crude oil contracts and other physical trading activity. This service provides a record of receipts, deliveries and transactions to each customer, including confirmation of trade matches, inventory management and scheduled movements.

The line transfer services also attract physical barrels to TCPL's facilities for final delivery to the ultimate owner. A pumpover occurs when the last title transfer is executed and the physical barrels are delivered out of TCPL's custody. TCPL owns and operates storage facilities primarily in Midland and Cushing with a storage capacity of approximately 2.9 million barrels to facilitate the pumpover business.

LSI distributes lubrication oils and specialty chemicals to natural gas pipelines, gas processors and industrial and commercial accounts. LSI's distribution networks are located in Colorado, Wyoming, Oklahoma, Kansas, New Mexico, Texas and Louisiana.

Customers

Our customers for the sale, transportation and storage of crude oil include major integrated oil companies and independent refiners. LSI distributes lubrication oils and specialty chemicals to natural gas pipelines, gas processors and industrial and commercial accounts, with networks located in Colorado, Wyoming, Oklahoma, Kansas, New Mexico, Texas and Louisiana. Gross sales revenue of the Upstream Segment attributable to the top 10 customers was $7.4 billion (75%), $5.9 billion (73%) and $3.8 billion (70%) for the years ended December 31, 2006, 2005 and 2004, respectively. For the year ended December 31, 2006, Valero Energy Corp. ("Valero") and BP Oil Supply Company accounted for 15% and 12%, respectively, of the Upstream gross sales revenue. For the years ended December 31, 2005 and 2004, Valero 15% and 17%, respectively, of the Upstream gross sales revenue. For the year ended December 31, 2006, Valero and BP Oil Supply Company accounted for 14% and 11%, respectively, of our total consolidated revenues. For the years ended December 31, 2005 and 2004, Valero accounted for 14% and 16%, respectively, of our total consolidated revenues.

Competition

The Upstream Segment faces competition from numerous sources. The most significant competitors in pipeline operations in our Upstream Segment are primarily common carrier and proprietary pipelines owned and operated by major oil companies, large independent pipeline companies and other companies in the areas where our pipeline systems receive and deliver crude oil. Competition among common carrier pipelines is based primarily on posted tariffs, quality of customer service, knowledge of products and markets, and proximity to refineries and connecting pipelines. The crude oil gathering and marketing business can be characterized by thin margins and intense competition for supplies of crude oil at the wellhead.

Midstream Segment – Gathering of Natural Gas, Transportation of NGLs and Fractionation of NGLs

We conduct business in our Midstream Segment through the following:

- our equity ownership in Jonah Gas Gathering Company, which gathers, purchases and sells natural gas;
- Val Verde Gas Gathering Company, L.P. (“Val Verde”), which gathers and treats natural gas for carbon dioxide removal;
- TEPPCO Midstream and its wholly owned subsidiaries, Chaparral Pipeline Company, L.P. and Quanah Pipeline Company, L.P. (collectively referred to as “Chaparral” or “Chaparral NGL system”), Panola Pipeline Company, L.P. (“Panola Pipeline”), Dean Pipeline Company, L.P. (“Dean Pipeline”) and Wilcox Pipeline Company, L.P. (“Wilcox Pipeline”), which transport NGLs; and
- TEPPCO Colorado, LLC (“TEPPCO Colorado”), which fractionates NGLs.

Properties and Operations

Our Midstream Segment gathers natural gas, transports NGLs and fractionates NGLs. We generally do not take title to the natural gas or NGLs, except for the wellhead sale and purchase of natural gas by Jonah to facilitate system operations and to provide a service to some of the producers on the system.

Volume information for the years ended December 31, 2006, 2005 and 2004, is presented below:

	For Year Ended December 31,		
	2006	2005	2004
Gathering – Natural Gas – Jonah (Bcf) (1)	472.9	415.2	354.5
Gathering – Natural Gas – Val Verde (Bcf)	181.9	180.7	144.5
Transportation – NGLs (MMBbls)	69.7	61.1	59.5
Fractionation – NGLs (MMBbls)	4.4	4.4	4.1

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah was deconsolidated and operating results after August 1, 2006, are included in equity earnings. However, this table includes Jonah’s gathering volumes for the full years ended December 31, 2006, 2005 and 2004.

Jonah Gas Gathering Joint Venture

We entered the natural gas gathering business in late 2001 when we purchased Jonah from Alberta Energy Company for approximately $360.0 million. DCP Midstream Partners, L.P. (formerly Duke Energy Field Services, LLC (“DEFS”)) managed and operated Jonah on our behalf under a contractual agreement through the second quarter of 2005, when we assumed these operations as a result of the change in ownership of our General Partner. The majority of the recent growth in the Midstream Segment is due to the expansions of Jonah in the Green River Basin in southwestern Wyoming.

On August 1, 2006, Enterprise, through its affiliate, Enterprise Gas Processing, LLC, became our joint venture partner by acquiring an interest in Jonah Gas Gathering Company, the general partnership through which we own an interest in the Jonah system. Previously, when Jonah was wholly-owned by us, operating results for Jonah were included in the consolidated Midstream Segment operating results. Effective with the formation of the joint venture on August 1, 2006, Jonah was deconsolidated, and we began using the equity method of accounting to account for our investment in Jonah.

The Jonah joint venture is governed by a management committee comprised of two representatives approved by Enterprise and two representatives approved by us, each with equal voting power. Enterprise is the operator of Jonah. Based upon a formula in the partnership agreement that takes into account the capital contributions of the parties to fund the Phase V expansion project discussed below, as well as certain capital expenditures made by us not related to the expansion project, we expect that after completion of the expansion and reaching certain milestones, we will own an interest in Jonah of approximately 80%, with Enterprise owning the remaining 20%.

Under a letter of intent we entered into in February 2006, Enterprise assumed the management of the Phase V expansion project and funded the initial costs of the expansion. Beginning with the August 1, 2006 formation of the Jonah joint venture, we reimbursed Enterprise for 50% of the expansion costs it had previously advanced, and we and Enterprise began sharing the costs of the expansion equally. We expect to reimburse Enterprise for approximately 50% of the Phase V expansion costs. To the extent the costs exceed an agreed upon base cost estimate of $415.2 million, we and Enterprise will each pay our respective ownership share (approximately 80% and 20%, respectively) of such costs.

In that regard, we have been working with producers to finalize the scope and design of the Phase V expansion to optimally serve the expected production needs in both the Jonah and Pinedale fields. However, the overall high level of activity in the greater Green River Basin area has strained locally available resources, which, coupled with rising steel costs, is likely to cause the final cost of the expansion to exceed the original agreed upon estimate.

We received all distributions from the joint venture until a specified milestone in the Phase V expansion was achieved in November of 2006, at which point, Enterprise became entitled to receive approximately 50% of the incremental cash flow from certain portions of the expansion project already placed in service. Upon completion of the next specified milestone, Enterprise will begin to share in revenues of the joint venture based upon the total amount of its capital contributions until, as discussed above, final ownership in the joint venture will be approximately 80% us and 20% Enterprise.

Jonah Gas Gathering System Business. The Jonah system serves the Jonah and Pinedale fields in Wyoming, which, according to the Energy Information Administration's 2005 estimates, were in the top ten natural gas producing fields in the United States. The system delivers natural gas to pipelines and gas processing facilities owned by others. From the processing facilities, the natural gas is delivered to several interstate pipeline systems located in the region for transportation to end-use markets throughout the Midwest, the West Coast and the Rocky Mountain regions. Interstate pipelines in the region include Kern River, Northwest, Colorado Interstate Gas and Questar. The Jonah system consists of approximately 643 miles of pipelines ranging in size from three inches to 36 inches in diameter, four compressor stations with an aggregate of approximately 92,000 horsepower and related metering facilities. Gas gathered on the Jonah system is collected from approximately 1,130 producing wells in southwestern Wyoming's Green River Basin.

In addition to gathering natural gas, Jonah also purchases and sells wellhead gas and condensate. The Jonah system sells condensate liquid from the natural gas stream to TCO based on a contracted price based generally on an index based crude oil price less a differential. In May 2006, we began to aggregate purchases of wellhead gas on Jonah and re-sell the aggregated quantities at key Jonah delivery points in order to facilitate operational needs and throughput on Jonah. The purchases and sales are generally contracted to occur in the same month to minimize price risk.

Jonah has fee based gathering agreements with fees that increase as field pressures decrease. Approximately 18 producers are connected to the system, of which seven have life-of-lease contracts that represented approximately 95% of the volumes of the system in 2006. Under these agreements, Jonah gathers and compresses the natural gas supplied to its gathering system and redelivers the natural gas to gas processing facilities and interstate pipelines located in the region for a fixed fee. It does not take title to the natural gas. Other than the effects of normal operating pressure fluctuations, we cannot influence or control the operation, development or production levels of the gas fields served by the Jonah system, which may be affected by price and price volatility, market demand, depletion rates of existing wells and changes in laws and regulations.

Since the acquisition of Jonah in 2001, we have expanded both the pipeline capacity and processing capacity of the Jonah system as follows:

- The Phase I expansion was completed in May 2002, at a cost of approximately $25.0 million and increased system capacity by 62%, from approximately 450 MMcf/d to approximately 730 MMcf/d.
- In October 2002, the Phase II expansion project was completed at a cost of approximately $35.3 million, which increased the capacity of the Jonah system from 730 MMcf/d to approximately 880 MMcf/d.
- In 2003, the Jonah system was again expanded by the Phase III project to include an 80-mile pipeline loop and 3,700 horsepower of new compression on the system and the building of a new 300 MMcf/d gas processing plant near Opal, Wyoming. Phase III was substantially completed during the fourth quarter of 2003, with system capacity increasing to 1,180 MMcf/d at a cost of approximately $53.4 million.
- Additional capacity of 100 MMcf/d was completed during the fourth quarter of 2004, at a cost of approximately $13.0 million.
- The Phase IV expansion project was completed in February 2006, at a cost of approximately $116.0 million and increased system capacity to 1.5 Bcf/d with the addition of 33,000 horsepower of compression and approximately 50 miles of pipeline.
- Through the joint venture with Enterprise, a Phase V expansion project is expected to increase the system capacity of the Jonah system from 1.5 Bcf/d to approximately 2.3 Bcf/d and to significantly reduce system operating pressures, which is anticipated to lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is expected to increase the system gathering capacity to approximately 2.0 Bcf/d, is scheduled to be completed in the second quarter of 2007. The pipeline looping part of the first portion of the expansion, which included the addition of 75 miles of 36-inch diameter pipe and 12 miles of 24-inch diameter pipe, was completed in December 2006. The second portion of the expansion is expected to be completed by the end of 2007. The anticipated cost of the Phase V expansion is expected to be approximately $444.0 million.

Pioneer Plant. On March 31, 2006, we sold our ownership interest in the Pioneer silica gel natural gas processing plant, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields located in Opal, Wyoming, to Enterprise for $38.0 million. The sale of the Pioneer plant was initiated because it was not an integral part of our Midstream Segment operations, and natural gas processing is not a core business. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes.

Val Verde Gas Gathering System

The Val Verde system, which we have owned since 2002 and operated since mid-2005, consists of approximately 400 miles of pipeline ranging in size from four inches to 36 inches in diameter, 14 compressor stations operating over 75,000 horsepower of compression and a large amine treating facility for the removal of carbon dioxide. The system has a gathering capacity of approximately one billion cubic feet of gas per day. The current treating capacity of the system is approximately 550 million cubic feet of gas per day. Treating capacity is affected by the content of carbon dioxide in the gas stream and is a more relevant measure than the gathering capacity of the system. The Val Verde system delivers gas to several interstate pipeline systems serving the western United States, as well as local New Mexico markets.

The Val Verde system gathers coal bed methane ("CBM") from the Fruitland Coal Formation of the San Juan Basin in New Mexico and Colorado. The system gathers CBM from more than 500 separate wells throughout northern New Mexico and southern Colorado, and provides gathering and treating services pursuant to long-term fixed-fee contracts with approximately 40 natural gas producers in the San Juan Basin. These contracts are generally twenty years in length, with evergreen clauses, the majority of which escalate annually. Under these contracts, Val Verde gathers the natural gas supplied to its gathering systems and redelivers the natural gas for a fixed fee. Under these arrangements, Val Verde does not take title to the natural gas. CBM volumes gathered on the Val Verde system have begun to decline, primarily due to the natural decline of CBM production by the producers in the field. Other than the effects of normal operating pressure fluctuations, we cannot influence or control the operation, development or production levels of the gas fields served by the Val Verde system, which may be affected by price and price volatility, market demand, depletion rates of existing wells and changes in laws and regulations.

In December 2004, we completed a 16-mile project to connect Val Verde with a third party gathering system originating in Colorado and entered into a seven year agreement to transport and treat natural gas through this connection. Val Verde transported an average of 125 MMcf/d from this interconnection in 2006.

NGL Transportation and Fractionation

The NGL pipelines of the Midstream Segment are located along the Texas Gulf Coast, East Texas and from southeastern New Mexico and West Texas to Mont Belvieu. They are all wholly owned and operated by our subsidiaries. Information about these NGL pipelines as of December 31, 2006, is set forth in the following table:

NGL Pipeline	Physical Capacity (barrels/day)	Description
Chaparral (1)	135,000	845 miles of pipeline – West Texas and New Mexico to Mont Belvieu, Texas
Quanah (1)	30,000	180 miles of pipeline – Sutton County, Texas to the Chaparral Pipeline near Midland, Texas
Panola (2)	46,000	189 miles of pipeline – Carthage, Texas to Mont Belvieu, Texas
San Jacinto (2)	12,000	34 miles of pipeline – Carthage, Texas to Longview, Texas
The southern portion of the Dean Pipeline (3)	10,000	155 miles of pipeline – South Texas to Point Comfort, Texas
Wilcox (4)	7,500	103 miles of pipeline – Southeast Texas

(1) The Chaparral NGL system, including the Quanah Pipeline, extends from West Texas and New Mexico to Mont Belvieu. Shippers on Chaparral pay a posted tariff. The rates are adjusted each July based upon a government approved Producer Price Index.

(2) The Panola Pipeline and San Jacinto Pipeline originate at an East Texas Plant Complex in Panola County, Texas, and transport NGLs for major integrated oil and gas companies.

(3) The southern portion of the Dean Pipeline originates in South Texas and transports NGLs for one customer into the customer owned pipeline at Point Comfort, Texas.

(4) The Wilcox Pipeline transported NGLs for a customer from its natural gas processing plant on a throughput agreement. The customer provided notice to terminate this service, and the Wilcox Pipeline was idled in December 2006. We are in the process of identifying an alternate use for the pipeline.

TEPPCO Colorado has two NGL fractionation facilities which separate NGLs into individual components. TEPPCO Colorado is currently supported by a fractionation agreement with DEFS through 2018, under which TEPPCO Colorado receives a variable fee, primarily a front-loaded fee determined by cumulative volumes fractioned during the contract year, for all fractionated volumes delivered to DEFS. Under an operation and maintenance agreement, DEFS also operates and maintains the fractionation facilities for TEPPCO Colorado. For these services, TEPPCO Colorado pays DEFS a set volumetric rate for all fractionated volumes delivered to DEFS.

Seasonality

At Jonah, new well connections are subject to seasonality as a result of winter range restrictions in the Pinedale field. Producers in the Pinedale field are prohibited from drilling activities typically during the November through April months due to wildlife restrictions, and as such, we are limited in our ability to connect new wells to the system during that time.

Customers

The Midstream Segment's customers for the gathering of natural gas include major integrated oil and gas companies and large to medium-sized independent producers. Natural gas from Jonah and Val Verde is delivered into major interstate gas pipelines for delivery primarily to markets in the western United States. The Midstream Segment's customers for the transporting of NGLs include affiliates of EPCO and other major integrated oil and gas companies.

At December 31, 2006, the Midstream Segment had approximately 67 customers. Revenue attributable to the top 10 customers was $158.0 million (77%) for the year ended December 31, 2006, of which EnCana Corporation, DEFS and its affiliates, Burlington Resources Inc. and BP Energy accounted for approximately 15%, 12%, 12% and 12%, respectively, of revenues of the Midstream Segment. At December 31, 2005, the Midstream Segment had approximately 70 customers. Revenue attributable to the top 10 customers was $190.0 million (85%) for the year ended December 31, 2005, of which EnCana Corporation, DEFS and its affiliates and Burlington Resources Inc. accounted for approximately 20%, 19% and 12%, respectively, of revenues of the Midstream Segment. At December 31, 2004, the Midstream Segment had approximately 75 customers. Revenue attributable to the top 10 customers was $172.8 million (83%) for the year ended December 31, 2004, of which EnCana Corporation, DEFS and its affiliates and Burlington Resources Inc. accounted for approximately 21%, 18% and 16%, respectively, of revenues of the Midstream Segment. During each of the three years ended December 31, 2006, 2005 and 2004, no single customer of the Midstream Segment accounted for 10% or more of total consolidated revenues.

Competition

Competition in the natural gas gathering operations of our Midstream Segment is based largely on reputation, efficiency, system reliability, system capacity and price arrangements. Key competitors in the gathering and treating segment include independent gas gatherers as well as other major integrated energy companies. Alternate gathering facilities may be available to producers served by our Midstream Segment, and those producers could also elect to construct proprietary gas gathering systems. Success in the gas gathering and treating business segment is based primarily on a thorough understanding of the needs of the producers served, a strong commitment to providing responsive, high-quality customer service, as well as proximity to new drilling and development.

The Midstream Segment's NGL pipeline operations face competition from a few sources. The most significant competition for the NGL pipeline operations of our Midstream Segment comes from pipelines owned and operated by major oil and gas companies and other large independent pipeline companies with contiguous operations. The ability to compete in the NGL pipeline area is based primarily on the quality of customer service and knowledge of products and markets.

Title to Properties

We believe we have satisfactory title to all of our assets. The properties are subject to liabilities in certain cases, such as contractual interests associated with acquisition of the properties, liens for taxes not yet due, easements, restrictions and other minor encumbrances. We believe none of these liabilities materially affect the value of our properties or our interest in the properties or will materially interfere with their use in the operation of our business.

Capital Expenditures

Capital expenditures, excluding acquisitions and contributions to joint ventures, totaled $170.0 million for the year ended December 31, 2006. Revenue generating projects include those projects which expand service into new markets or expand capacity into current markets. Capital expenditures to sustain existing operations include projects required by regulatory agencies or required life-cycle replacements. System upgrade projects improve operational efficiencies or reduce cost. We capitalize interest costs incurred during the period that construction is in progress. The following table identifies capital expenditures by segment for the year ended December 31, 2006 (in millions):

	Revenue Generating	Sustaining Existing Operations	System Upgrades	Capitalized Interest	Total
Downstream Segment	$ 30.7	$ 20.5	$ 19.1	$ 5.0	$ 75.3
Midstream Segment	39.8	0.2	1.0	1.9	42.9
Upstream Segment	25.6	16.3	4.3	2.2	48.4
Other	—	3.0	0.4	—	3.4
Total	$ 96.1	$ 40.0	$ 24.8	$ 9.1	$ 170.0

Revenue generating capital spending by the Downstream Segment totaled $30.7 million and was used primarily for the continued integration of assets we acquired from Texas Genco, LLC (“Genco”) in 2005, the expansion of our truck loading terminal in Bossier City, Louisiana, the expansion of our pipeline system extending from Seymour to Indianapolis, Indiana and additional propane capacity in our Northeast market. Revenue generating capital spending by the Midstream Segment totaled $39.8 million and was used primarily for the expansion of the Jonah system prior to the formation of the joint venture, after which Jonah’s capital spending is reflected through capital contributions to equity investments, and additional well connections on both the Jonah and Val Verde systems. Revenue generating capital spending by the Upstream Segment totaled $25.6 million and was used primarily for the expansion of our pipelines and facilities in South Texas, West Texas and Cushing, Oklahoma, including integration of previously acquired assets. In order to sustain existing operations, we spent $20.5 million for various Downstream Segment pipeline projects, $0.2 million for the Midstream Segment and $16.3 million for Upstream Segment facilities. An additional $24.8 million was spent on system upgrade projects among all of our business segments.

We estimate that capital expenditures, excluding acquisitions and joint venture contributions, for 2007 will be approximately $300.0 million (including $8.0 million of capitalized interest). We expect to spend approximately $251.0 million for revenue generating projects. We expect to spend approximately $38.0 million to sustain existing operations (including $12.0 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 $3.0 million to improve operational efficiencies and reduce costs among all of our business segments. Amounts related to Jonah capital expenditures will be reported as joint venture contributions due to the deconsolidation of Jonah on August 1, 2006.

During 2007, TE Products may be required to contribute additional cash to Centennial to cover capital expenditures or other operating needs and to MB Storage to cover capital expenditures prior to the sale of the asset. Additionally, we expect to contribute approximately $120.0 million to our Jonah joint venture for the construction of the Phase V expansion during 2007 and approximately $31.0 million for other capital expenditures. 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.

Regulation

Certain of our crude oil, petroleum products and natural gas liquids pipeline systems ("liquids pipelines") are interstate common carrier pipelines subject to rate regulation by the FERC, under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 ("Energy Policy Act"). The ICA prescribes that interstate tariffs must be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC regulations require that interstate oil pipeline transportation rates be filed with the FERC and posted publicly.

The ICA permits interested persons to challenge proposed new or changed rates and authorizes the FERC to investigate such rates and to suspend their effectiveness for a period of up to seven months. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it may require the carrier to refund the revenues in excess of the prior tariff during the term of the investigation. The FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of its complaint.

On October 24, 1992, Congress passed the Energy Policy Act. The Energy Policy Act deemed just and reasonable under the ICA (*i.e*., "grandfathered") liquids pipeline rates that were in effect for the twelve months preceding enactment and that had not been subject to complaint, protest or investigation. The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party must show that it was previously contractually barred from challenging the rates, or that the economic circumstances of the liquids pipeline that were a basis for the rate or the nature of the service underlying the rate had substantially changed or that the rate is unduly discriminatory or preferential. Some but not all of our interstate liquids pipeline rates are considered grandfathered under the Energy Policy Act. There is currently pending before the U.S. Court of Appeals for the D.C. Circuit ("D.C. Circuit") a challenge to the FERC's standards for assessing when such a substantial change has occurred. We cannot at this time predict what effect, if any, the decision in that case will have on the ability of parties to challenge grandfathered rates.

Certain other rates for our interstate liquids pipeline services are charged pursuant to a FERC-approved indexing methodology, which allows a pipeline to charge rates up to a prescribed ceiling that changes annually based on the change from year to year in the Producer Price Index for finished goods ("PPI"). A rate increase within the indexed rate ceiling is presumed to be just and reasonable unless a protesting party can demonstrate that the rate increase is substantially in excess of the pipeline's costs. Effective March 21, 2006, FERC issued its final order concluding its second five-year review of the oil pipeline pricing index. FERC concluded that for the five-year period commencing July 1, 2006, liquids pipelines charging indexed rates may adjust their indexed ceilings annually by the PPI plus 1.3 percent ("PPI Index"). At the end of that five year period, in July 2011, the FERC will once again review the PPI Index to determine whether it continues to measure adequately the cost changes in the oil pipeline industry.

As an alternative to using the PPI Index, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, competitive market showings ("Market-Based Rates") or agreements with all of the pipeline's shippers that the rate is acceptable. TE Products has been granted permission by the FERC to utilize Market-Based Rates for all of its refined products movements other than the Little Rock, Arkansas, Arcadia and Shreveport-Arcadia, Louisiana destination markets, which are currently subject to the PPI Index. As with all rates for service on an oil pipeline subject to FERC regulation under the ICA, TE Products must file its market-based rates with FERC and charge those rates on a non-discriminatory basis, such that the same Market-Based Rate shall be charged to similarly situated shippers. With respect to LPG movements, TE Products uses the PPI Index. All interstate transportation movements of crude oil by TCPL are subject to the PPI Index as are the NGL interstate transportation movements on the Chaparral NGL system.

Because of the complexity of ratemaking, the lawfulness of any rate is never assured. The FERC uses prescribed rate methodologies for approving regulated tariff rates for transporting crude oil and refined products. These methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting increased costs. Changes in the FERC's approved methodology for approving rates could adversely affect us. Adverse decisions by the FERC in approving our regulated rates could adversely affect our cash flow. Challenges to our tariff rates could be filed with the FERC. We believe the transportation rates currently charged by our interstate common carrier pipelines are in accordance with the ICA. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by our interstate liquids pipelines.

In that regard, one element of the FERC's cost-of-service methodology as it affects partnerships such as us remains under review. In a case involving Lakehead Pipe Line Company, L.P., a partnership that operates a crude oil pipeline, the FERC concluded in its Opinion No. 397 that Lakehead was entitled to include in calculating its rates an income tax allowance only with respect to the portion of its earnings that are attributable to its partners that are not individuals, rationalizing that income attributable to individuals would be subject to only one level of taxation. The parties subsequently settled the case, so there was no judicial review of the FERC's decision. The FERC subsequently applied this approach in proceedings involving SFPP, L.P., which is a subsidiary of a publicly traded limited partnership engaged in the transportation of petroleum products. In the first SFPP proceeding, Opinion No. 435, the FERC (among other things) affirmed Opinion No. 397's determination that there should not be an income tax allowance built into a petroleum pipeline's rates for income attributable to non-corporate partners.

Following several FERC orders on rehearing, the matter was appealed to the D.C. Circuit. The court found the Lakehead policy to lack a reasonable basis and vacated the portion of the FERC's rulings that permitted SFPP an income tax allowance in accordance with that policy. The court remanded the issue to the FERC for further consideration, and the FERC thereafter initiated a broader inquiry into the implications of the court's decision on other FERC-regulated companies. That was followed by the issuance of the FERC's "Policy Statement on Income Tax Allowances" ("Policy Statement") on May 4, 2005, which addressed the circumstances in which a partnership or other pass-through entity would be permitted to include a tax allowance in its cost of service. On December 16, 2005, the FERC issued its "Order on Initial Decision and on Certain Remanded Cost Issues" in various dockets involving SFPP (the "SFPP Order"). Among other things, the SFPP Order applied the Policy Statement to the specific facts of the SFPP case, suggesting how the FERC will treat other Master Limited Partnership ("MLP") petroleum pipelines. The SFPP Order confirmed that an MLP is entitled to a tax allowance with respect to partnership income for which there is an "actual or potential income tax liability" and determined that a unitholder that is required to file a Form 1040 or Form 1120 tax return that includes partnership income or loss is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income. The FERC also established certain other presumptions, including that corporate unitholders are presumed to be taxed at the maximum corporate tax rate of 35% while individual unitholders (and certain other types of unitholders taxed like individuals) are presumed to be taxed at a 28% tax rate.

Both the SFPP Order and the Policy Statement were appealed to the D.C. Circuit, in a case that was argued before the court on December 12, 2006. The matter is currently awaiting a decision.

The intrastate liquids pipeline transportation services we provide are subject to various state laws and regulations that affect the rates we charge and terms and conditions of that service. Although state regulation typically is less onerous than FERC regulation, proposed and existing rates subject to state regulation and the provision of non-discriminatory service are subject to challenge by complaint.

The Val Verde and Jonah natural gas gathering systems are exempt from FERC regulation under the Natural Gas Act of 1938 since they are intrastate gas gathering systems rather than interstate transmission pipelines. However, FERC regulation still significantly affects the Midstream Segment, directly or indirectly, by its influences on the parties that produce the natural gas gathered on the Val Verde and Jonah systems as well as the parties that transport that natural gas. In addition, in recent years, the FERC has pursued pro-competition policies in its regulation of interstate natural gas pipelines. If the FERC does not continue the pro-competition policies as it considers pipeline rate case proposals, revisions to rules and policies that affect shipper rights of access to interstate natural gas transportation capacity or proposals by natural gas pipelines to allow natural gas pipelines to charge negotiated rates without rate ceiling limits, such policy changes could have an adverse effect on the gathering rates the Midstream Segment is able to charge in the future.

Environmental and Safety 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.

The following is a discussion of all material environmental and safety laws and regulations that relate to our operations. We believe that we are in material compliance with all these environmental and safety 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.

Water

The Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act (“CWA”), and comparable state laws impose strict controls against the discharge of oil and its derivatives into navigable waters. The CWA provides penalties for any discharges of petroleum products in reportable quantities and imposes substantial potential liability for the costs of removing petroleum or other hazardous substances. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of a release of petroleum or its derivatives in navigable waters or into groundwater. Spill prevention control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent a petroleum tank release from impacting navigable waters. The Environmental Protection Agency (“EPA”) has adopted regulations that require us to have permits in order to discharge certain storm water run-off. Storm water discharge permits may also be required by certain states in which we operate. These permits may require us to monitor and sample the storm water run-off. The CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. We believe that our costs of compliance with these CWA requirements will not have a material adverse effect on our operations.

The primary federal law for oil spill liability is the Oil Pollution Act of 1990 (“OPA”), which addresses three principal areas of oil pollution — prevention, containment and cleanup, and liability. OPA applies to vessels, offshore platforms and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport oil, shore facilities are required to file oil spill response plans with the United States Coast Guard, the United States Department of Transportation Office of Pipeline Safety (“OPS”) or the EPA, as appropriate. Numerous states have enacted laws similar to OPA. Under OPA and similar state laws, responsible parties for a regulated facility from which oil is discharged may be liable for removal costs and natural resource damages. Any unpermitted release of petroleum or other pollutants from our pipelines or facilities could result in fines or penalties as well as significant remedial obligations.

Contamination resulting from spills or releases of petroleum products is an inherent risk within the petroleum pipeline industry. To the extent that groundwater contamination requiring remediation exists along our pipeline systems as a result of past operations, we believe any such contamination could be controlled or remedied without having a material adverse effect on our financial position, but such costs are site specific, and we cannot be assured that the effect will not be material in the aggregate.

Air Emissions

Our operations are subject to the Federal Clean Air Act (the “Clean Air Act”) and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions.

Our permits and related compliance under the Clean Air Act, as well as recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional, non-attainment areas, may require our operations to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some of our facilities are included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the Clean Air Act. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than any other similarly situated company.

Congress is currently considering proposed legislation directed at reducing “greenhouse gas emissions”. It is not possible at this time to predict how legislation that may be enacted to address greenhouse gas emissions would impact our business. However, future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial position, results of operations and cash flows.

Risk Management Plans

We are subject to the EPA’s Risk Management Plan (“RMP”) regulations at certain locations. This regulation is intended to work with the Occupational Safety and Health Act (“OSHA”) Process Safety Management regulation (see “Safety Matters” below) to minimize the offsite consequences of catastrophic releases. The regulation required us to develop and implement a risk management program that includes a five-year accident history, an offsite consequence analysis process, a prevention program and an emergency response program. We are operating in compliance with our risk management program.

Solid Waste

We generate hazardous and non-hazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. We also utilize waste minimization and recycling processes to reduce the volumes of our waste. Amendments to RCRA required the EPA to promulgate regulations banning the land disposal of all hazardous wastes unless the wastes meet certain treatment standards or the land-disposal method meets certain waste containment criteria.

Environmental Remediation

The Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), also known as “Superfund,” imposes liability, without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of a facility where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at a facility. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, our pipeline systems generate wastes that may fall within CERCLA's definition of a "hazardous substance." In the event a disposal facility previously used by us requires clean up in the future, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed.

At December 31, 2006, we have an accrued liability of $1.8 million related to sites requiring environmental remediation activities. Discussion of legal proceedings that relate to environmental remediation is included elsewhere in this Report under the caption Item 3. Legal Proceedings.

DOT Pipeline Compliance Matters

We are subject to regulation by the United States Department of Transportation ("DOT") under the Accountable Pipeline and Safety Partnership Act of 1996, sometimes referred to as the Hazardous Liquid Pipeline Safety Act ("HLPSA"), and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. The HLPSA covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the Secretary of Transportation. We believe that we are in material compliance with these HLPSA regulations.

We are subject to the DOT regulation requiring qualification of pipeline personnel. The regulation requires pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. The intent of this regulation is to ensure a qualified work force and to reduce the probability and consequence of incidents caused by human error. The regulation establishes qualification requirements for individuals performing covered tasks. We believe that we are in material compliance with these DOT regulations.

We are also subject to the DOT Integrity Management regulations, which specify how companies should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas ("HCA"). HCA are defined as populated areas, unusually sensitive environmental areas and commercially navigable waterways. The regulation requires the development and implementation of an Integrity Management Program ("IMP") that utilizes internal pipeline inspection, pressure testing, or other equally effective means to assess the integrity of HCA pipeline segments. The regulation also requires periodic review of HCA pipeline segments to ensure adequate preventative and mitigative measures exist and that companies take prompt action to address integrity issues raised by the assessment and analysis. In compliance with these DOT regulations, we identified our HCA pipeline segments and have developed an IMP. We believe that the established IMP meets the requirements of these DOT regulations.

Safety Matters

We are also subject to the requirements of the federal OSHA and comparable state statutes. We believe we are in material compliance with OSHA and state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures.

The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to employees, state and local governmental authorities and local citizens upon request. We are subject to OSHA Process Safety Management ("PSM") regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves certain flammable liquid or gas. We believe we are in material compliance with the OSHA regulations.

Antitrust Matters

The FTC has imposed certain restrictions on us in connection with its 2006 investigation of us related to DFI's acquisition of our General Partner in 2005. For further discussion, see Item 3. Legal Proceedings.

Employees

We do not directly employ any officers or other persons responsible for managing our operations. As of December 31, 2006, approximately 1,000 persons spend 100% of their time engaged in the management and operations of our business, and the cost for their services is reimbursed 100% to EPCO under the ASA. An additional approximately 1,100 persons assigned to EPCO's shared services organizations spend all or a portion of their time engaged in our business. The cost for their services is reimbursed to EPCO under the ASA generally based on the time allocated for services provided to us during the year. In addition, there are approximately 50 contract maintenance and other various personnel who provide services to us. For additional information regarding our relationship with EPCO, please read Item 13 of this Report.

Available Information

As a large accelerated filer, we electronically file certain documents with the SEC under the Securities Exchange Act of 1934 (the "Exchange Act"). We file annual reports on Form 10-K; quarterly reports on Form 10-Q; and current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. From time to time, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site (http://www.sec.gov) that contains reports and other information regarding issuers that file electronically with the SEC, including us.

We provide electronic access to our periodic and current reports on our Internet website (http://www.teppco.com). These reports are available as soon as reasonably practicable after we electronically file such materials with, or furnish such materials to, the SEC. You may also contact our Investor Relations Department at (800) 659-0059 for paper copies of these reports free of charge.

Item 1A. *Risk Factors*

There are many factors that may affect the business and results of operations of us and our joint ventures. Additional discussion regarding factors that may affect the businesses and operating results of us and our joint ventures is included elsewhere in this Report, including under the captions "Cautionary Note Regarding Forward-Looking Statements," "Items 1 and 2. Business and Properties," "Item 3. Legal Proceedings," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and "Item 13. Certain Relationships and Related Transactions, and Director Independence." If one or more of these risks actually occur, our business, financial position or results of operations could be materially and adversely affected.

Risks Relating to Our Business

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

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

Acquisitions and business expansions involve numerous risks, including difficulties in the assimilation of the assets and operations of the acquired businesses, inefficiencies and difficulties that arise because of unfamiliarity with new assets, personnel and the businesses associated with them and new geographic areas and the diversion of management's attention from other business concerns. Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Following an acquisition, we may discover previously unknown liabilities associated with the acquired business for which we may have no recourse or limited recourse under applicable indemnification provisions.

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

As of December 31, 2006, we had approximately $1.6 billion of consolidated debt outstanding, consisting of $490.0 million of borrowings under our revolving credit facility and $1.1 billion principal amount of senior notes. The amount of our future debt could have significant effects on our operations, including, among other things:

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

Our revolving credit facility contains restrictive financial and other covenants that, among other things, limit our ability to incur additional indebtedness, make distributions in excess of Available Cash (see Note 14 in the Notes to the Consolidated Financial Statements for discussion of Available Cash), and complete mergers, acquisitions and sales of assets. The facility also prevents us from making a distribution if an event of default under the facility has occurred or would occur as a result of the distribution. Our breach of these restrictions or restrictions in the provisions of our other indebtedness could permit the holders of the indebtedness to declare all amounts outstanding thereunder to be immediately due and payable and, in the case of our revolving credit facility, to terminate all commitments to extend further credit. Although our revolving credit facility restricts our ability to incur additional debt above certain levels, any debt we may incur in compliance with these restrictions may still be substantial.

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

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

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

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

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

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

We are a holding company with no material operations. Our only significant assets are the equity interests we own in our subsidiaries and joint ventures. As a result, we depend upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of their cash to us in order to meet our obligations and to allow us to make distributions to our partners. In addition, charter documents and other agreements governing our joint ventures may restrict or limit the occurrence and amount of distributions to us under certain circumstances, including by giving authority to establish available cash for distribution to management committees or other governing bodies that we do not control.

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

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

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

The 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 FERC. In addition, pipelines may not confer any undue preference upon any shipper. Shippers may protest, and the FERC may investigate, the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months. It can also require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful. The FERC and interested parties can also challenge tariff rates that have become final and effective. Because of the complexity of rate making, the lawfulness of any rate is never assured. 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 services we provide are subject to various state laws and regulations that apply to the rates we charge and the terms and conditions of the services we offer. Although state regulation typically is less onerous than FERC regulation, the rates we charge and the provision of our services may be subject to challenge.

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

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

In May 2005, the FERC issued a policy statement permitting the inclusion of an income tax allowance in the cost of service-based rates of a pipeline for partnership interests held by partners with an actual or potential income tax liability on public utility income, if the pipeline proves that the owner of the partnership interest has an actual or potential income tax liability. On December 16, 2005, the FERC issued its first significant case-specific oil pipeline review of the income tax allowance issue in another pipeline company's rate case. The FERC reaffirmed its new income tax allowance policy and directed the subject pipeline to provide certain evidence necessary for the pipeline to determine its income tax allowance. The new tax allowance policy and the December 16 order have been appealed to the United States Court of Appeals for the District of Columbia Circuit. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service. Currently, none of our tariffs are calculated using cost of service rate methodologies. If, however, the policy statement on income tax allowances is applied to us differently in the future or is modified on judicial review, our rates may be subject to calculation using cost of service methodologies and this might adversely affect us.

Competition could adversely affect our operating results.

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

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

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

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

Our primary market areas are located in the Northeast, Midwest and Southwest regions of the United States. We have a concentration of trade receivable balances due from major integrated oil companies, independent oil companies and other pipelines and wholesalers. These concentrations of market areas may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. For the years ended December 31, 2006, 2005 and 2004, Valero Energy Corp. accounted for 14%, 14% and 16%, respectively, of our total consolidated revenues, and for the year ended December 31, 2006, BP Oil Supply Company accounted for 11% of our total consolidated revenues. No other single customer accounted for 10% or more of our total consolidated revenues for the years ended December 31, 2006, 2005 and 2004.

Our risk management policies cannot eliminate all commodity price risks. In addition, any non-compliance with our risk management policies could result in significant financial losses.

To enhance utilization of certain assets and our operating income, we purchase petroleum products. Generally, it is our policy to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Through these transactions, we seek to establish a margin for the commodity purchased by selling the same commodity for physical delivery to third party users, such as producers, wholesalers, independent refiners, marketing companies or major oil companies. These policies and practices cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated physical supply could expose us to risk of loss resulting from price changes if we are required to obtain alternative supplies to cover these transactions. We are also exposed to basis risks when a commodity is purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including price risks on product inventory, such as pipeline linefill, which must be maintained in order to facilitate transportation of the commodity on our pipelines. In addition, our marketing operations involve the risk of non-compliance with our risk management policies. We cannot assure you that our process and procedures will detect and prevent all violations of our risk management policies, particularly if deception or other intentional misconduct is involved.

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

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

Reduced demand could affect shipments on our pipelines.

Our business depends in large part on the demand for the various petroleum products we gather, transport and store in the markets served by our pipelines. Reductions in that demand adversely affect our business. Market demand varies based upon the different end uses of the petroleum products we gather, transport and store. We cannot predict the impact of future fuel conservation measures, alternate fuel requirements, government regulation, technological advances in fuel economy and energy-generation devices, exploration and production activities, and actions by foreign nations; all of which could reduce the demand for the petroleum products in the areas we serve. For example:

- Demand for gasoline, which has in recent years accounted for approximately 45% of our refined products transportation revenues, depends upon price, prevailing economic conditions and demographic changes in the markets we serve.
- Weather conditions, government policy and crop prices affect the demand for refined products used in agricultural operations.
- Demand for jet fuel, which has in recent years accounted for approximately 15% of our refined products revenues, depends on prevailing economic conditions and military usage.
- Propane deliveries are generally sensitive to the weather and meaningful year-to-year variances have occurred and will likely continue to occur.

The success of our Jonah gas gathering operations is substantially dependent upon Enterprise.

We own our interest in the Jonah gas gathering system, which represents a significant component of our Midstream Segment and its potential for future growth, through a joint venture with Enterprise, which is under common control with us by EPCO and its affiliates. The joint venture is governed by a management committee comprised of two representatives approved by an Enterprise affiliate and two representatives approved by subsidiaries of ours. We expect to ultimately own an approximate 80% interest in the joint venture, with Enterprise's affiliate owning the remaining approximate 20%. However, each representative on the management committee is entitled to one vote, and the joint venture agreement generally requires the affirmative vote of a majority of the members of the management committee to approve an action. Moreover, Enterprise is responsible for managing construction of the Phase V expansion of the system. We expect to reimburse Enterprise for approximately 50% of these construction costs. To the extent the costs exceed an agreed upon base cost estimate of $415.2 million, we and Enterprise will each pay our respective ownership share (approximately 80% and 20%, respectively) of such costs. We and Enterprise may not always agree on the best course of action for the joint venture. If such a disagreement were to occur, we would not be able to cause the joint venture to take action that we believed to be in our best interests. Further, Enterprise may experience unanticipated delays or costs in construction or operation of the project, which could require additional capital contributions by us and Enterprise or diminish expected benefits from the project. Any of these factors could materially and adversely affect our results of operations, financial condition and prospects.

Profits and cash flow from Jonah and Val Verde depend on the volumes of natural gas produced from the fields served by the systems and are subject to factors beyond our control.

Regional production levels drive the volume of natural gas gathered on Jonah and Val Verde. We cannot influence or control the operation or development of the gas fields we serve. For example, production levels may be affected by:

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

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

The level of drilling activity is dependent on economic and business factors beyond our control. The primary factor that impacts drilling decisions is the price of oil and natural gas. These commodity prices reached record levels during 2006, but current prices have declined in recent months. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our gathering systems, which would lead to reduced throughput levels on these systems. Other factors that impact production decisions include producers’ capital budget limitations, the ability of producers to obtain necessary drilling and other governmental permits, the availability and cost of drilling rigs and other drilling equipment, and regulatory changes. Because of these factors, even if new natural gas reserves were discovered in areas served by our systems, producers may choose not to develop those reserves or may connect them to different systems.

In accordance with industry practice, we do not obtain independent evaluations of natural gas reserves dedicated to our gathering systems, including Jonah. Accordingly, volumes of natural gas gathering on our pipeline systems in the future could be less than we anticipate, which could adversely affect our cash flow and our ability to make cash distributions to unitholders.

In accordance with industry practice, we do not obtain independent evaluations of natural gas reserves connected to our gathering systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to those systems or the anticipated lives of such reserves. If the total reserves or estimated lives of the reserves connect to our gathering systems, Jonah and Val Verde, are less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas gathered on our systems in the future could be less than we anticipate. A decline in the volumes of natural gas gathered on our pipeline systems could have an adverse effect on our business, results of operations and financial condition.

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

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

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

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

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

Our facilities are subject to multiple environmental, health and safety obligations and potential liabilities under a variety of federal, state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges, and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could influence our results of operations. If an accidental leak, spill or release of hazardous substances occurs at any facilities that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held jointly and severally liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. Any or all of this could materially affect our results of operations and cash flows. We currently own or lease, and have owned or leased, many properties that have been used for many years to terminal or store crude oil, petroleum products or other chemicals. Owners, tenants or users of these properties may have disposed of or released hydrocarbons or solid wastes on or under them. Additionally, some sites we operate are located near current or former refining and terminaling operations. There is a risk that contamination has migrated from those sites to ours.

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

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

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

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

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

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

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

Our operations are subject to the many hazards inherent in the transportation 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, 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 our behalf, although insurance will not cover many types of hazards that might occur, including certain environmental accidents, and will not cover amounts up to 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 subsequent to the terrorist attacks on September 11, 2001 and the hurricanes of 2005 have made it more difficult for us to obtain certain types of 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.

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

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

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities are located, and we are therefore subject to the risk of increased costs to maintain necessary land use. We obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, or increased costs to renew such rights, could have a material adverse effect on our business, financial position, results of operations or cash flows.

Mergers among our customers or competitors could result in lower volumes being shipped on our pipelines, thereby reducing the amount of cash we generate.

Mergers among our existing customers or competitors could provide strong economic incentives for the combined entities to utilize systems other than ours and we could experience difficulty in replacing lost volumes and revenues. Because a significant portion of our operating costs are fixed, a reduction in volumes would result in not only a reduction of revenues, but also a decline in net income and cash flow of a similar magnitude, which would reduce our ability to meet our financial obligations and make distributions to you.

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

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

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

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

Prior to making any distribution on our Units, we will reimburse EPCO and its affiliates, including our General Partner, for expenses they incur on our behalf. The payment of these amounts and allocated overhead to EPCO and its affiliates could adversely affect our ability to pay cash distributions to holders of our Units. These amounts include all costs in managing and operating our business, including compensation of executives for time allocated to us, director compensation, costs for rendering administrative staff and support services and overhead allocated to us by EPCO. Please read Item 13. Certain Relationships and Related Transactions, and Director Independence. In addition, our General Partner and its affiliates may provide other services to us for which we will be charged fees as determined by our General Partner.

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

The directors and officers of our General Partner and its affiliates (including EPCO and other affiliates of EPCO) have duties to manage the General Partner in a manner that is beneficial to its owners, which are controlled by EPCO. At the same time, the General Partner has duties to manage us in a manner that is beneficial to us. EPCO also controls other publicly traded partnerships, Enterprise and DEP, that engage in similar lines of business. We have significant business relationships with Enterprise and EPCO and other entities controlled by Dan L. Duncan. Mr. Duncan’s economic interests in Enterprise and these other related entities are more substantial than his economic interest in us. Therefore, our General Partner’s duties to us may conflict with the duties of its officers and directors to its owners. As a result of these conflicts of interest, our General Partner may favor its own interest or those of EPCO or its owners over the interest of our unitholders. Possible conflicts may include, among others, the following:

- Enterprise, EPCO and their affiliates may engage in substantial competition with us on the terms set forth in the ASA.
- Neither our Partnership Agreement nor any other agreement requires EPCO or its affiliates (other than our General Partner) to pursue a business strategy that favors us. Directors and officers of EPCO and the general partner of Enterprise and their affiliate have a fiduciary duty to make decisions in the best interest of their shareholders or unitholders, which may be contrary to our interests.
- Our General Partner is allowed to take into account the interests of parties other than us, such as EPCO, Enterprise and their affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders.
- Some of the officers of EPCO who provide services to us also may devote significant time to the business of Enterprise or its other affiliates and will be compensated by EPCO for such services.
- Our Partnership Agreement limits the liability and reduces the fiduciary duties of our General Partner, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing Units, unitholders will be deemed to have consented to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law.

- Our General Partner determines the amount and timing of asset purchases and sales, operating expenditures, capital expenditures, borrowings, repayments of indebtedness, issuances of additional partnership securities and cash reserves, each of which can affect the amount of cash that is available for distribution to our unitholders.
- Our General Partner determines which costs, including allocated overhead, incurred by it and its affiliates are reimbursable by us.
- Our Partnership Agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our General Partner generally seeks to limit its liability regarding our contractual obligations.
- Our General Partner may exercise its rights to call and purchase all of our Units if at any time it and its affiliates own 85% or more of the outstanding Units.
- Our General Partner controls the enforcement of obligations owed to us by it and its affiliates, including the ASA.
- Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

Please read Item 13. Certain Relationships and Related Party Transactions, and Director Independence.

Unitholders have limited voting rights and control of management.

Our General Partner manages and controls our activities. Unitholders have no right to elect the General Partner or the directors of the General Partner on an annual or other ongoing basis. However, if the General Partner resigns or is removed, its successor may be elected by holders of a majority of the Units. Unitholders may remove the General Partner only by a vote of the holders of at least 66$^{2}/_{3}$ % of the Units. Our Partnership Agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations. As a result, unitholders will have limited influence on matters affecting our operations, and third parties may find it difficult to gain control of us or influence our actions.

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

We have no officers or employees and rely solely on officers of our General Partner and employees of EPCO and its affiliates. These relationships may create conflicts of interest regarding corporate opportunities and other matters, and the resolution of any such conflicts may not always be in our or our unitholders' best interests. In addition, these overlapping employees allocate their time among us, EPCO and other affiliates of EPCO and may face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

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

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

Our Partnership Agreement limits our General Partner's fiduciary duties to unitholders and restricts the remedies available to unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that reduce the standards to which our General Partner would otherwise be held by state fiduciary duty law. For example, our Partnership Agreement:

- Permits our General Partner to make a number of decisions on its behalf, as opposed to in its capacity as our General Partner. This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its registration rights and the determination of whether to consent to any merger or consolidation of the Partnership or amendment to the Partnership Agreement;
- Provides in the absence of bad faith by the audit and conflicts committee of the board of directors of our General Partner or our General Partner, the resolution, action or terms made, taken or provided in connection with a potential conflict of interest transaction will be conclusive and binding on all person (including all partners) and will not constitute a breach of the Partnership Agreement or any standard of care or duty imposed by law;
- Provides the General Partner shall not be liable to the Partnership or any partner for its good faith reliance on the provisions of the Partnership Agreement to the extent it has duties, including fiduciary duties, and liabilities at law or in equity;
- Generally provides that affiliate transactions and resolutions of conflicts of interest not approved by the audit and conflicts committee of the board of directors of our General Partner must be on terms no less favorable to us than those generally provided to or available from unrelated third parties or otherwise be "fair and reasonable" to us;
- Provides that it shall be presumed that the resolution of any conflicts of interest by our General Partner or the audit and conflicts committee of the board of directors of our General Partner was not made in bad faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption; and
- Provides that our General Partner and its officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the General Partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.

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

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

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

Under Delaware law, our General Partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those of our contractual obligations that are expressly made without recourse to our General Partner. Further, unitholders could be held liable for our obligations to the same extent as a General Partner if a court determined that:

- We were conducting business in a state, but had not complied with that particular state's partnership statute; or
- the right of limited partners to remove our General Partner or to take other action under our Partnership Agreement constituted participation in the "control" of our business.

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

The credit and risk profile of our General Partner and its owners could adversely affect our credit ratings and profile, which could increase our borrowing costs or hinder our ability to raise capital.

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

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

The ownership interests in us that are owned or controlled by EPCO and its affiliates, which include all of the membership interests in our General Partner, are pledged as security under the credit facility of an affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, Enterprise and us. If EPCO were to default under the credit facility, its lender banks could own our General Partner.

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

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

Tax Risks to Unitholders

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

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

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

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level federal income taxation. Our Partnership Agreement currently provides that if a law is enacted that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, the minimum quarterly distribution amount and the target distribution level will be adjusted to reflect the impact of that law on us, including any related imposition of state and local income taxes.

In addition, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we will be subject to a new entity-level tax on the portion of our income generated in Texas beginning in 2007. Specifically, the Texas margin tax will be imposed at a maximum effective rate of 0.7% of our gross income apportioned to Texas. Imposition of such tax on us by Texas, or any other state, will reduce the cash available for distribution to you.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Item 1B. ***Unresolved Staff Comments***

None.

Item 3. ***Legal Proceedings***

In the fall of 1999, the General Partner and TE Products were named as defendants in a lawsuit in Jackson County Circuit Court, Jackson County, Indiana, styled *Ryan E. McCleery and Marcia S. McCleery, et al. and Michael and Linda Robson, et al. v. Texas Eastern Corporation, et al.* In the lawsuit, the plaintiffs contend, among other things, that we and other defendants stored and disposed of toxic and hazardous substances and hazardous wastes in a manner that caused the materials to be released into the air, soil and water. They further contend that the release caused damages to the plaintiffs. In their complaint, the plaintiffs allege strict liability for both personal injury and property damage together with gross negligence, continuing nuisance, trespass, criminal mischief and loss of consortium. The plaintiffs are seeking compensatory, punitive and treble damages. On March 18, 2005, we entered into Release and Settlement Agreements with the McCleery plaintiffs dismissing all of these plaintiffs' claims on terms that did not have a material adverse effect on our financial position, results of operations or cash flows. Although we did not settle with all plaintiffs and we therefore remain named parties in the *Michael and Linda Robson, et al. v. Texas Eastern Corporation, et al*. action, a co-defendant has agreed, by Cooperative Defense Agreement, to fund the defense and satisfy all final judgments which might be rendered with the remaining claims asserted against us. Consequently, we do not believe that the outcome of these remaining claims will have a material adverse effect on our financial position, results of operations or cash flows.

On December 21, 2001, TE Products was named as a defendant in a lawsuit in the 10th Judicial District, Natchitoches Parish, Louisiana, styled *Rebecca L. Grisham et al. v. TE Products Pipeline Company, Limited Partnership*. In this case, the plaintiffs contend that our pipeline, which crosses the plaintiffs' property, leaked toxic products onto their property and, consequently caused damages to them. We have filed an answer to the plaintiffs' petition denying the allegations, and we are defending ourselves vigorously against the lawsuit. The plaintiffs assert damages attributable to the remediation of the property of approximately $1.4 million. This case has been stayed pending the completion of remediation pursuant to Louisiana Department of Environmental Quality ("LDEQ") requirements. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

In 1991, we were named as a defendant in a matter styled *Jimmy R. Green, et al. v. Cities Service Refinery, et al.* as filed in the 26th Judicial District Court of Bossier Parish, Louisiana. The plaintiffs in this matter reside or formerly resided on land that was once the site of a refinery owned by one of our co-defendants. The former refinery is located near our Bossier City facility. Plaintiffs are pursuing class certification and have claimed personal injuries and property damage arising from alleged contamination of the refinery property in the amount of $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 or its affiliates. The complaint names as defendants the General Partner; the Board of Directors of the General Partner; the parent companies of the General Partner, including EPCO; Enterprise and certain of its affiliates; and Dan L. Duncan. We are named as a nominal defendant.

The complaint alleges, among other things, that certain of the transactions proposed in the Proxy Statement, including a proposal to reduce the General Partner's maximum percentage interest in our distributions in exchange for Units (the "Issuance Proposal"), are unfair to our unitholders and constitute 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 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 or its affiliates that are unfair to us or otherwise unfairly favored Enterprise or its affiliates over us. The complaint alleges that such transactions include the Jonah joint venture entered into by us and an Enterprise affiliate in August 2006 (citing the fact that our AC Committee (defined below) did not obtain a fairness opinion from an independent investment banking firm in approving the transaction) and the sale by us to an Enterprise affiliate of the Pioneer plant in March 2006 and the impending divestiture of our interest in MB Storage in connection with an investigation by the FTC. As more fully described in the Proxy Statement, the Audit and Conflicts Committee of the Board of Directors of the General Partner ("AC Committee") recommended the Issuance Proposal for approval by the Board of Directors of the General Partner. The complaint also alleges that Richard S. Snell, Michael B. Bracy and Murray H. Hutchison, constituting the three members of the AC Committee, cannot be considered independent because of their alleged ownership of securities in Enterprise and its affiliates and their relationships with Mr. Duncan.

The complaint seeks relief (i) rescinding transactions in the complaint that have been consummated or awarding rescissory damages in respect thereof; (ii) awarding damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the complaint; and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts.

On September 22, 2006, the plaintiff in the action filed a motion to expedite the proceedings, requesting the Court to schedule a hearing on plaintiff's motion for a preliminary injunction to enjoin the defendants from proceeding with the special meeting of unitholders. On September 26, 2006, the defendants advised the Court that we would provide to our unitholders specified supplemental disclosures, which were included in the Form 8-K and supplemental proxy materials we filed with the SEC on October 5, 2006. The special meeting was convened on December 8, 2006, at which our unitholders approved all of the proposals. In light of the foregoing, we believe that the plaintiff's grounds for seeking relief by requiring us to issue a proxy statement that corrects the alleged misstatements and omissions in the Proxy Statement and enjoining the special meeting are moot. On November 17, 2006, the defendants (other than us, the nominal defendant) moved to dismiss the complaint. While we cannot predict the ultimate outcome, we do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

In 1994, the LDEQ issued a compliance order for environmental contamination at our Arcadia, Louisiana, facility. In 1999, our Arcadia facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this contamination. Effective March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility. This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility. At December 31, 2006, we have an accrued liability of $0.1 million for remediation costs at our Arcadia facility. We do not expect that the completion of the remediation program proposed to the LDEQ will have a future material adverse effect on our financial position, results of operations or cash flows.

On July 27, 2004, we received notice from the United States Department of Justice ("DOJ") of its intent to seek a civil penalty against us related to our November 21, 2001, release of approximately 2,575 barrels of jet fuel from our 14-inch diameter pipeline located in Orange County, Texas. The DOJ, at the request of the EPA, is seeking a civil penalty against us for alleged violations of the CWA arising out of this release, as well as three smaller spills at other locations in 2004 and 2005. We have agreed with the DOJ on a proposed penalty of $2.9 million, along with our commitment to implement additional spill prevention measures, and expect to finalize the settlement in the second quarter of 2007. We do not expect this settlement to have a material adverse effect on our financial position, results of operations or cash flows.

One of the spills encompassed in our current settlement discussion with the DOJ involved a 37,450-gallon release from Seaway on May 13, 2005 at Colbert, Oklahoma. This release was remediated under the supervision of the Oklahoma Corporation Commission, but resulted in claims by neighboring landowners that have been settled for approximately $0.7 million. In addition, the release resulted in a Corrective Action Order by the DOT. Among other requirements of this Order, we were required to reduce the operating pressure of Seaway by 20% until completion of required corrective actions. The corrective actions were completed and on June 1, 2006, we increased the operating pressure of Seaway back to 100%. We have a 50% ownership interest in Seaway, and any settlement should be covered by our insurance. We do not expect the completion of our obligations relating to the Colbert release to have a material adverse effect on our financial position, results of operations or cash flows.

On September 18, 2005, a propane release and fire occurred at our Todhunter facility, near Middletown, Ohio. The incident resulted in the death of one of our employees; there were no other injuries. Repairs to the impacted facilities have been completed. On March 17, 2006, we received a citation from OSHA arising out of this incident, with a penalty of $0.1 million. The settlement of this citation did not have a material adverse effect on our financial position, results of operations or cash flows.

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

On February 24, 2005, the General Partner was acquired from DEFS by DFI. The General Partner owns a 2% general partner interest in us and is the general partner of the Partnership. On March 11, 2005, the Bureau of Competition of the FTC delivered written notice to DFI's legal advisor that it was conducting a non-public investigation to determine whether DFI's acquisition of our General Partner may substantially lessen competition or violate other provisions of federal antitrust laws. We and our General Partner cooperated fully with this investigation.

On October 31, 2006, an FTC order and consent agreement ending its investigation became final. The order requires the divestiture of our 50% interest in MB Storage and certain related assets to one or more FTC-approved buyers in a manner approved by the FTC and subject to its final approval. Because we did not divest the interest and related assets by December 31, 2006, the order allows the FTC to appoint a divestiture trustee to oversee their sale to one or more approved buyers. The order contains no minimum price for the divestiture and requires that we provide the acquirer or acquirers the opportunity to hire employees who spend more than 10% of their time working on the divested assets. The order also imposes specified operational, reporting and consent requirements on us including, among other things, in the event that we acquire interests in or operate salt dome storage facilities for NGLs in specified areas. We have made application with the FTC to approve a buyer and sale terms for our interest in MB Storage and certain related pipelines, and we expect to close on such sale during the first quarter of 2007.

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 lawsuits and other proceedings will not individually or in the aggregate have a future material adverse effect on our consolidated financial position, results of operations or cash flows.

Item 4. ***Submission of Matters to a Vote of Security Holders***

On December 8, 2006, we held a special meeting of our unitholders. At the meeting, our unitholders approved seven proposals provided for in our definitive proxy statement dated September 5, 2006, as supplemented and filed with the SEC. By approving the proposals, the unitholders effected or adopted:

- Four proposals by which we amended and restated our Partnership Agreement (the "Amendment Proposals"):

    a) A proposal to revise certain provisions of our Partnership Agreement that relate to distributions and capital contributions, including reduction of our General Partner's maximum percentage interest in our quarterly distributions from 50% to 25% (the "IDR Reduction Amendment"), elimination of our General Partner's requirement to make capital contributions to us to maintain a 2% capital account, and adjustment of our minuimum quarterly distribution and target distribution levels for entity-level taxes (51,875,620 "For," 3,812,756 "Against," 1,288,075 "Abstain").

    b) A proposal to change various voting percentage requirements of our Partnership Agreement, in most cases from 66 2/3% of outstanding Units to a majority of outstanding Units (50,912,506 "For," 4,702,226 "Against," 1,361,719 "Abstain").

    c) A proposal to supplement and revise certain provisions of our Partnership Agreement that relate to conflicts of interest and fiduciary duties (50,909,929 "For," 4,155,340 "Against," 1,911,182 "Abstain").

    d) A proposal to make additional amendments to our Partnership Agreement to provide for certain registration rights of our General Partner, for the maintenance of the separateness of our partnership from any other person or entity and other miscellaneous matters (51,735,496 "For," 3,661,239 "Against," 1,579,716 "Abstain").

- A proposal to issue Units to our General Partner as consideration for the IDR Reduction Amendment (the "Issuance Proposal") (50,103,934 "For," 5,096,150 "Against," 1,776,366 "Abstain").

- A proposal to approve the terms of the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (49,567,252 "For," 5,589,417 "Against," 1,818,781 "Abstain").

- A proposal to approve the terms of the EPCO, Inc. TPP Employee Unit Purchase Plan (50,613,444 "For," 4,478,510 "Against," 1,884,497 "Abstain").

The Amendment Proposals and the Issuance Proposal were conditioned upon one another, such that all were required to pass in order for any of them to pass.

PART II

Item 5. *Market for Registrant's Units and Related Unitholder Matters and Issuer Purchases of Equity Securities*

Our Units are listed and traded on the New York Stock Exchange ("NYSE") under the symbol "TPP". The high and low trading prices of our Units in 2006 and 2005, respectively, as reported on the NYSE, were as follows:

	2006		2005	
Quarter	High	Low	High	Low
First	$39.00	$35.29	$45.45	$38.53
Second	38.49	35.20	44.72	39.85
Third	37.65	34.44	42.75	39.61
Fourth	41.86	36.90	41.15	33.15

Based on the information received from our transfer agent, as of February 23, 2007, there were approximately 1,400 unitholders of record of our Units.

The quarterly cash distributions on our Units for the years ended December 31, 2006 and 2005, were as follows:

Record Date	Payment Date	Amount Per Unit
April 29, 2005	May 6, 2005	$0.6625
July 29, 2005	August 5, 2005	0.675
October 31, 2005	November 7, 2005	0.675
January 31, 2006	February 7, 2006	0.675
April 28, 2006	May 5, 2006	$ 0.675
July 31, 2006	August 7, 2006	0.675
October 31, 2006	November 7, 2006	0.675
January 31, 2007	February 7, 2007	0.675

We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. Pursuant to the Partnership Agreement, the General Partner receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds (see Note 14 in the Notes to the Consolidated Financial Statements).

Effective December 8, 2006, upon receiving approval of our unitholders at a special meeting, we amended and restated our Partnership Agreement, among other things, to reduce our General Partner's maximum percentage interest in our quarterly distributions from 50% to 25% (the "IDR Reduction Amendment") in exchange for 14,091,275 Units ("Issuance"). Due to the IDR Reduction Amendment and the Issuance, subsequent increases in the level of our quarterly distribution on our Units would result in lower total cash distributions on partnership interests held by our General Partner and its affiliates than under our Previous Partnership Agreement, as the increased distribution to our General Partner and its affiliates due to the distribution rate increase and the Issuance will be more than offset by the lower distributions to it as a result of the IDR Reduction Amendment. Conversely, if we subsequently decrease the level of our quarterly distribution on our Units, total cash distributions on partnership interests held by our General Partner and its affiliates will be higher than under the Previous Partnership Agreement, since the distributions foregone by them as a result of the IDR Reduction Amendment will be more than offset by the lower distributions on our Units, including those Units issued pursuant to the Issuance. For additional information regarding the amendment to our Partnership Agreement, please see Items 1 and 2. Business and

Properties, "– 2006 Developments," Item 4. Submission of Matters to a Vote of Security Holders and our definitive proxy statement dated September 5, 2006 on file with the SEC. We expect to continue to pay comparable quarterly cash distributions, assuming no adverse change in our financial position, results of operations or cash flows. Although we have never reduced our quarterly distributions, there can be no assurance that we will not do so in the future.

We are a publicly traded master limited partnership and are not subject to federal income tax. Instead, unitholders are required to report their allocated share of our income, gain, loss, deduction and credit, regardless of whether we make distributions. We have made quarterly distribution payments since May 1990.

Distributions of cash paid by us to a unitholder will not result in taxable gain or income except to the extent the aggregate amount distributed exceeds the tax basis of the Units owned by the unitholder.

Recent Sales of Unregistered Securities

As described above, on December 8, 2006, we issued 14,091,275 Units to our General Partner as consideration for the IDR Reduction Amendment. The Units were issued to the General Partner in a transaction not involving a public offering and exempt from registration pursuant to Section 4(2) of the Securities Act of 1933, as amended. Effective as of December 8, 2006, the General Partner distributed the newly issued units to its member, which in turn caused them to be distributed to other affiliates of EPCO.

Units Authorized for Issuance Under Equity Compensation Plan

Please read the information included under Item 12 of this Report, which is incorporated by reference into this Item 5.

Issuer Purchases of Equity Securities

We did not repurchase any of our Units during 2006.

Item 6. *Selected Financial Data*

The following tables set forth, for the periods and at the dates indicated, our selected consolidated financial and operating data. The selected financial data as of and for the years ended December 31, 2006, 2005 and 2004, reflect Jonah Gas Gathering Company's Pioneer plant, which was sold on March 31, 2006, as discontinued operations. The selected financial data as of and for the years ended December 31, 2006, 2005, 2004 and 2003 is derived from our audited consolidated financial statements. The selected financial data for the year ended December 31, 2002, is derived from unaudited consolidated financial statements and, in the opinion of management, has been prepared in accordance with accounting principles generally accepted in the United States of America and reflects all adjustments which are, in the opinion of management, necessary for a fair presentation of results for this period. The financial data should be read in conjunction with our audited consolidated financial statements included in the Index to Consolidated Financial Statements on page F-1 of this Report. See also Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	For Year Ended December 31, (in thousands, except per Unit amounts)				
	2006	2005	2004	2003	2002 (1)
Income Statement Data:					
Operating revenues:					
Sales of petroleum products	$ 9,080,516	$ 8,061,808	$ 5,426,832	$ 3,766,651	$ 2,823,800
Transportation – Refined products	152,552	144,552	148,166	138,926	123,476
Transportation – LPGs	89,315	96,297	87,050	91,787	74,577
Transportation – Crude oil	38,822	37,614	37,177	29,057	27,414
Transportation – NGLs	43,838	43,915	41,204	39,837	38,870
Gathering – Natural gas	123,933	152,797	140,122	135,144	90,053
Mont Belvieu operations	—	—	—	—	15,238
Other revenues	78,509	68,051	67,539	54,430	48,735
Total operating revenues	9,607,485	8,605,034	5,948,090	4,255,832	3,242,163
Purchases of petroleum products	8,967,062	7,986,438	5,367,027	3,711,207	2,772,328
Operating expenses (2)	278,448	255,359	257,372	235,028	197,726
General and administrative expenses	31,348	33,143	28,016	20,409	15,830
Depreciation and amortization	108,252	110,729	112,284	100,728	86,032
Gains on sales of assets	(7,404)	(668)	(1,053)	(3,948)	—
Operating income	229,779	220,033	184,444	192,408	170,247
Interest expense – net	(86,171)	(81,861)	(72,053)	(84,250)	(66,192)
Equity earnings	36,761	20,094	22,148	12,874	8,853
Other income – net (including interest income)	2,965	1,135	1,320	748	1,827
Income before deferred income tax expense	183,334	159,401	135,859	121,780	114,735
Deferred income tax expense	652	—	—	—	—
Income from continuing operations	182,682	159,401	135,859	121,780	114,735
Discontinued operations (3)	19,369	3,150	2,689	—	—
Net income	$ 202,051	$ 162,551	$ 138,548	$ 121,780	$ 114,735

	For Year Ended December 31, (in thousands, except per Unit amounts)				
	2006	2005	2004	2003	2002 (1)
Basic and diluted income per Unit: (4)					
Continuing operations	$ 1.77	$ 1.67	$ 1.53	$ 1.47	$ 1.74
Discontinued operations (3)	0.19	0.04	0.03	—	—
Net income per Unit	$ 1.96	$ 1.71	$ 1.56	$ 1.47	$ 1.74

	December 31, 2006	2005	2004	2003	2002 (1)
	(in thousands)				
Balance Sheet Data:					
Property, plant and equipment – net	$1,642,095	$1,960,068	$1,703,702	$1,619,163	$1,587,824
Total assets	3,922,092	3,680,538	3,186,284	2,934,480	2,765,900
Total debt	1,603,287	1,525,021	1,480,226	1,339,650	1,377,692
Class B Units held by related party	—	—	—	—	103,234
Partners' capital	1,320,330	1,201,370	1,011,103	1,102,809	889,449

	For Year Ended December 31, 2006	2005	2004	2003	2002 (1)
	(in thousands, except per Unit amounts)				
Cash Flow Data:					
Net cash provided by continuing operating activities (3)	$ 271,552	$ 250,723	$ 263,896	$ 242,424	$ 234,917
Net cash provided by operating activities	273,073	254,505	267,167	242,424	234,917
Capital expenditures to sustain existing operations (5)	(39,966)	(40,783)	(41,733)	(32,864)	(21,978)
Capital expenditures	(170,046)	(220,553)	(156,749)	(126,707)	(133,372)
Distributions paid	(278,566)	(251,101)	(233,057)	(202,498)	(151,853)
Distributions paid per Unit (4)	$ 2.70	$ 2.68	$ 2.64	$ 2.50	$ 2.35

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

(2) Includes operating fuel and power and taxes – other than income taxes.

(3) Reflects the Pioneer plant as discontinued operations for the years ended December 31, 2004, 2005 and 2006. The Pioneer plant was constructed as part of the Phase III expansion of the Jonah system and was completed during the first quarter of 2004.

(4) Per Unit calculation includes 13,359,597 Units issued in 2002 and 9,188,957 Units issued in 2003, net of retirement of Class B Units of 3,916,547. No Units were issued in 2004. In 2005 and 2006, 6,965,000 Units and 5,750,000 Units were issued, respectively. On December 8, 2006, we issued 14,091,275 Units to our General Partner in consideration for the IDR Reduction Amendment.

(5) Capital expenditures to sustain existing operations include projects required by regulatory agencies or required life-cycle replacements.

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

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

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

This discussion contains forward-looking statements based on current expectations that are subject to risks and uncertainties, such as statements of our plans, objectives, expectations and intentions. Our actual results and the timing of events could differ materially from those anticipated or implied by the forward-looking statements discussed here as a result of various factors, including, among others, those set forth under the "Cautionary Note Regarding Forward-Looking Statements" and "Risk Factors" herein.

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

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 are also focused on our continued growth through expansion of the assets that we own and through the construction and acquisition of assets that complement our current operations. We operate and report in three business segments:

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

Downstream Segment

Our Downstream Segment revenues are earned from transportation, marketing and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. Our Downstream Segment transportation activities generate revenue primarily through tariffs filed with the FERC applicable to shippers of refined products and LPGs on our pipelines. 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 sales at the Aberdeen truck rack to independent wholesalers and retailers of refined products. These purchases and sales are generally contracted to occur on the same day. Storage revenue is generated from fees based on storage volumes contracted for by customers.

Our Downstream Segment is dependent in large part on the demand for refined products and LPGs in the markets served by its pipelines and the availability of alternative supplies to serve those markets. As such, quantities and mix of products transported may vary. Market demand for refined products shipped in the Downstream Segment varies based upon the different end uses of the products, while transportation tariffs vary among specific product types. Demand for gasoline, which in recent years has accounted for approximately 45% of the Downstream Segment's refined products transportation revenues, depends upon market price, prevailing economic conditions, demographic changes in the markets served in the Downstream Segment and availability of gasoline produced in refineries located in those markets. Generally, higher market prices of gasoline has little impact on deliveries in the short-term, but may have a more significant impact on us in the long-term due to long lead times associated with expansion of refinery production capacities and conversion of the auto fleets to more fuel efficient models. Demand for distillates, which in recent years has accounted for approximately 21% of the Downstream Segment's refined products transportation revenues, is affected by truck and railroad freight, the price of natural gas used by utilities, which use distillates as a substitute for natural gas when the price of natural gas is high, and usage for agricultural operations, which is affected by weather conditions, government policy and crop prices. Distillate is more sensitive to short-term changes in price as customers shift from the use of trucking for freight transportation to railcars. Demand for jet fuel, which in recent years has accounted for approximately 15% of the Downstream Segment's refined products revenues, depends on prevailing economic conditions and military usage. Increases in the market price of jet fuel and the impact on airlines has resulted in the use of more efficient airplanes and reductions in total capacity and the number of scheduled flights. High market price of propane could result in the use of alternative fuel sources and tend to reduce the summer and early fall fill of consumer storage of propane. As a result, market price volatility may affect transportation volumes and revenues from period to period.

We generally realize higher revenues in the Downstream Segment during the first and fourth quarters of each year since these operations are somewhat seasonal. Refined products volumes are generally higher during the second and third quarters because of greater demand for gasolines during the spring and summer driving seasons. LPGs volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating. 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 investments in MB Storage, which we are required to divest (see Note 18 in the Notes to the Consolidated Financial Statements), and in Centennial (see Note 9 in the Notes to the Consolidated Financial Statements).

Upstream Segment

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil, and distribution of lubrication oils and specialty chemicals principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale or delivery of the crude oil to local refineries, marketers or other end users. Revenues are also generated from trade documentation and pumpover services, primarily at Cushing, Oklahoma, and Midland, Texas.

The areas served by our gathering and transportation operations are geographically diverse, and the forces that affect the supply of the products gathered and transported vary by region. Crude oil prices and production levels affect the supply of these products. The demand for gathering and transportation is affected by the demand for crude oil by refineries, refinery supply companies and similar customers in the regions served by this business.

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

Our Upstream Segment also includes our equity investment in Seaway (see Note 9 in the Notes to the Consolidated Financial Statements). Seaway consists of large diameter pipelines that transport crude oil from Seaway’s marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

Midstream Segment

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 (Chaparral) from West Texas and New Mexico to Mont Belvieu; and fractionation of NGLs in Colorado. Under its gathering agreements, Val Verde gathers the natural gas supplied to its gathering systems and redelivers the natural gas for a fixed fee. CBM volumes gathered on the Val Verde system have begun to decline, primarily due to the natural decline of CBM production by the producers in the field. Transportation revenues are recognized as NGLs are delivered for customers. Fractionation revenues are recognized ratably over the contract year as products are delivered. We generally do not take title to the natural gas or NGLs, except for the wellhead sale and purchase of natural gas by Jonah to facilitate system operations and to provide a service to some of the producers on the system. Therefore, the results of our Midstream Segment are not directly affected by changes in the prices of natural gas or NGLs.

Our Midstream Segment also includes our equity investment in Jonah (see Note 9 in the Notes to the Consolidated Financial Statements). Jonah, which is a joint venture between us and an affiliate of Enterprise, owns a natural gas gathering system in the Green River Basin in southwestern Wyoming. Under its gathering agreements, Jonah gathers and compresses the natural gas supplied to its gathering system and redelivers the natural gas to gas processing facilities and interstate pipelines located in the region for a fixed fee. Prior to August 1, 2006, when Jonah was wholly-owned by us, operating results for Jonah were included in the consolidated Midstream Segment operating results. Effective August 1, 2006, we entered into the joint venture with Enterprise's affiliate, upon which Jonah was deconsolidated, and its operating results since August 1, 2006, have been accounted for under the equity method of accounting. Operating results of the Pioneer plant, which was part of our Midstream Segment and which we sold to an Enterprise affiliate in March 2006, are shown as discontinued operations for the years ended December 31, 2006, 2005 and 2004.

Other than the effects of normal operating pressure fluctuations, we cannot influence or control the operation, development or production levels of the gas fields served by the Jonah and Val Verde systems, which may be affected by price and price volatility, market demand, depletion rates of existing wells and changes in laws and regulations.

Business Trends

In 2006, our management performed a detailed analysis of the business environment, and identified several key trends or factors that we believe will drive our growth opportunities in 2007 and beyond. With each trend or factor, we identify below the related strategies or opportunities we believe that factor presents.

- We expect that Canadian crude oil imports to the U.S. will increase.
  - Develop competitive options to move Canadian crude oil to U.S. refining customers with third parties through an optimum combination of new pipeline construction and existing pipeline assets.
- We expect that crude oil imports to the U.S. Gulf Coast will increase.
  - Build onshore or offshore crude oil discharge, handling and transportation facilities to optimize the U.S. Gulf Coast marine delivery options for imported crude oil.
  - Strengthen market position around our existing market base by focusing on activities in West Texas, South Texas and Red River areas, align Seaway Crude Pipeline Company with key refiners and suppliers and increase margins by expanding services and managing costs.
  - Focus on new refinery supply markets with existing assets and expand our asset base in the upper Texas Gulf Coast as well as utilize the Cushing, Oklahoma, acquired storage and newly constructed storage for mid-continent refineries.
- We expect that refined products imports to the U.S. will increase.
  - Acquire or develop facilities to take advantage of these increased volumes.
  - Enhance refined products storage business.
- We expect to see changes in commercial terminal ownership and operations.
  - Acquire refined products terminals and distribution assets to provide logistical service offerings to companies seeking to outsource or partner.
- Standards for use of ethanol and other renewable fuels are currently mandated to double from 2005 to 2012; under federal legislation, renewable fuels will comprise increasing percentages of U.S. fuel supply, with a fuel standard of 7.5 billion gallons for such fuels set for 2012.
  - Participate in the aggregation, terminaling and transportation associated with the overall supply and distribution of ethanol.
- We expect to see continued natural gas gathering and related service opportunities in the Jonah, Pinedale and San Juan Basin areas.
  - Continued development and expansion of the Jonah system which serves the Jonah and Pinedale fields in our Midstream Segment. Through additional Jonah expansions, which should be completed in the fourth quarter of 2007, we expect to increase the capacity to 2.3 billion cubic feet per day.
  - Adding new volumes and improving the operating efficiency of the Val Verde system in our Midstream Segment in New Mexico's San Juan Basin, through new connections of conventional and Colorado coal seam gas.

- o Capitalize on our assets that are positioned in active producing areas important to future domestic gas supply.

We also believe other growth opportunities are available to us, including through: expanding our West Texas system and storage capacity at Cushing in our Upstream Segment; increasing throughput on our Midstream Segment NGL systems; expanding our Downstream Segment system delivery capability of gasoline and diesel fuel in the Indianapolis and Chicago market areas; expanding service to the Midwest markets experiencing a supply shortfall; pursuing growth of refined products market share by expanding deliveries to existing markets and by developing new markets; utilizing available Downstream Segment system capacity of Centennial to move refined products to Midwest market areas, which enables us to increase movements of long-haul propane volumes; expanding our Downstream Segment gathering capacity of refined products along the upper Texas Gulf Coast; and pursuing acquisitions or organic growth projects in any of our business segments that would complement our current operations. We cannot assure that management will achieve all or any of these objectives or those described above.

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

Critical Accounting Policies and Estimates

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

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

Revenue and Expense Accruals

We routinely make accruals based on estimates for both revenues and expenses due to the timing of compiling billing information, receiving certain third party information and reconciling our records with those of third parties. The delayed information from third parties includes, among other things, actual volumes of crude oil purchased, transported or sold, adjustments to inventory and invoices for purchases, actual natural gas and NGL deliveries and other operating expenses. We make accruals to reflect estimates for these items based on our internal records and information from third parties. Most of the estimated accruals are reversed in the following month when actual information is received from third parties and our internal records have been reconciled.

The most difficult accruals to estimate are power costs, property taxes and crude oil margins. Power cost accruals generally involve a two to three month estimate, and the amount varies primarily for actual power usage. Power costs are dependent upon the actual volumes transported through our pipeline systems and the various power rates charged by numerous power companies along the pipeline system. Peak demand rates, which are difficult to predict, drive the variability of the power costs. For the year ended December 31, 2006, approximately 10% of our power costs were recorded using estimates. A variance of 10% in our aggregate estimate for power costs would have an approximate $0.6 million impact on annual earnings. Property tax accruals involve significant tax rate estimates in numerous jurisdictions. Actual property taxes are often not known until the tax bill is settled in subsequent periods, and the tax amount can vary for tax rate changes and changes in tax methods or elections. A variance of 10% in our aggregate estimate for property taxes could have up to an approximate $1.2 million impact on annual earnings. Crude oil margin estimates are based upon historical crude oil marketing volumes, factoring in current market events and prices of crude oil. We use an average of prices that were in effect during the applicable month to determine the expected revenue amount, and we determine the margin by evaluating the actual margins of the prior twelve months. As of December 31, 2006, approximately 7% of our annual crude oil margin is recorded using estimates. A variance from this estimate of 10% would impact the net of revenues and purchases by approximately $1.1 million on an annual basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Reserves for Environmental Matters

At December 31, 2006, we have accrued a liability of $1.8 million for our estimate of the future payments we expect to pay for environmental costs to remediate existing conditions attributable to 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. A variance of 10% in our aggregate estimate for environmental costs would have an approximate $0.2 million impact on annual earnings. For information concerning environmental regulation and environmental costs and contingencies, see Items 1 and 2. Business and Properties, "– Environmental and Safety Matters".

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Some of these circumstances include changes in laws and regulations relating to restoration and abandonment requirements; changes in expected costs for dismantlement, restoration and abandonment as a result of changes, or expected changes, in labor, materials and other related costs associated with these activities; changes in the useful life of an asset based on the actual known life of similar assets, changes in technology, or other factors; and changes in expected salvage proceeds as a result of a change, or expected change in the salvage market. At December 31, 2006 and 2005, the net book value of our property, plant and equipment was $1,642.1 million and $1,960.1 million, respectively. We recorded $78.9 million, $80.8 million and $80.7 million in depreciation expense during the years ended December 31, 2006, 2005 and 2004, respectively.

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

Goodwill and Intangible Assets

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

During 2002, we adopted SFAS No. 142, *Goodwill and Other Intangible Assets*, which discontinues the amortization of goodwill and intangible assets that have indefinite lives and requires an annual test of impairment based on a comparison of the estimated fair value to carrying values. The evaluation of impairment for goodwill and intangible assets with indefinite lives under SFAS 142 requires the use of projections, estimates and assumptions as to the future performance of the operations, including anticipated future revenues, expected future operating costs and the discount factor used. Actual results could differ from projections resulting in revisions to our assumptions and, if required, recognizing an impairment loss. Based on our assessment, we do not believe our goodwill is impaired, and we have not recorded a charge from the adoption of SFAS 142 (see Note 12 in the Notes to the Consolidated Financial Statements). At December 31, 2006 and 2005, the recorded value of goodwill was $15.5 million and $16.9 million, respectively. The decrease in the value of goodwill is due to the deconsolidation of Jonah effective August 1, 2006 as a result of the formation of a joint venture with Enterprise, partially offset by an increase in goodwill related to the acquisition of MTMI in November 2006.

At December 31, 2006 and 2005, we had $153.1 million of intangible assets, net of accumulated amortization, related to natural gas transportation contracts which were recorded as part of our acquisition of Val Verde on June 30, 2002. At December 31, 2005, we had $344.0 million of intangible assets, net of accumulated amortization, related to natural gas transportation contracts which were recorded as part of our acquisitions of Jonah on September 30, 2001, and Val Verde. The decrease in intangible assets is due to the deconsolidation of Jonah effective August 1, 2006 as a result of the formation of a joint venture with Enterprise. The value assigned to the natural gas ptransportation contracts required management to make estimates regarding the fair value of the assets acquired. In connection with the acquisition of Val Verde, we assumed fixed-term gas transportation contracts with customers in the San Juan Basin in New Mexico and Colorado. We assigned $239.6 million of the purchase price to these fixed-term contracts based upon a fair value appraisal at the time of the acquisition. The value assigned to intangible assets is amortized on a unit-of-production basis, based upon the actual throughput of the system compared to the expected total throughput for the lives of the contracts. On a quarterly basis, we update throughput estimates and evaluate the remaining expected useful life of the contract assets based upon the best available information. A variance of 10% in our aggregate production estimate for the Val Verde systems would have an approximate $2.5 million impact on annual amortization expense. Changes in the estimated remaining production will impact the timing of amortization expense reported for future periods.

At December 31, 2006, we have $42.2 million of excess investments, net of accumulated amortization, in our equity investments in Centennial and Seaway, which are being amortized over periods ranging from 10 to 39 years and in our investment in Jonah, in which amortization will begin as the assets are placed in service (see Note 12 in Notes to the Consolidated Financial Statements). The value assigned to our excess investment in Centennial was created upon its formation. Approximately $30.0 million is related to a contract and is being amortized on a unit-of-production basis based upon the volumes transported under the contract compared to the guaranteed total throughput of the contract over a 10-year life. The remaining $3.4 million is related to a pipeline and is being amortized on a straight-line basis over the life of the pipeline, which is 35 years. The value assigned to our excess investment in Seaway was created upon acquisition of our 50% ownership interest in 2000. We are amortizing the $27.1 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to the life of the pipeline. The value assigned to our excess investment in Jonah was created upon its formation related to the construction of the Phase V expansion. Amortization of this excess investment will begin upon the various phases of the Phase V expansion being placed into service. A variance of 10% in our amortization expense allocated to equity earnings could have up to an approximate $0.4 million impact on annual earnings.

Results of Operations

The following table summarizes financial information by business segment for the years ended December 31, 2006, 2005 and 2004 (in thousands):

	For Year Ended December 31,		
	2006	2005	2004
Operating revenues:			
Downstream Segment	$ 304,301	$ 287,191	$ 279,400
Upstream Segment	9,109,629	8,110,239	5,475,995
Midstream Segment (1)	201,269	211,171	195,902
Intersegment eliminations	(7,714)	(3,567)	(3,207)
Total operating revenues	9,607,485	8,605,034	5,948,090
Operating income:			
Downstream Segment	91,262	88,143	71,263
Upstream Segment	70,840	33,174	32,265
Midstream Segment (1)	65,499	98,716	80,916
Intersegment eliminations	2,178	—	—
Total operating income	229,779	220,033	184,444
Equity earnings (losses):			
Downstream Segment	(8,018)	(2,984)	(6,544)
Upstream Segment	11,905	23,078	28,692
Midstream Segment (1)	35,052	—	—
Intersegment eliminations	(2,178)	—	—
Total equity earnings	36,761	20,094	22,148
Earnings before interest:			
Downstream Segment	84,746	85,914	65,506
Upstream Segment	83,540	56,408	61,363
Midstream Segment (1)	101,219	98,940	81,043
Interest expense	(96,852)	(88,620)	(76,280)
Interest capitalized	10,681	6,759	4,227
Income before deferred income tax expense	183,334	159,401	135,859
Deferred income tax expense	652	—	—
Income from continuing operations	182,682	159,401	135,859
Discontinued operations	19,369	3,150	2,689
Net income	$ 202,051	$ 162,551	$ 138,548

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah was deconsolidated and has been subsequently accounted for as an equity investment (see Note 9 in the Notes to the Consolidated Financial Statements).

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

Downstream Segment

The following table provides financial information for the Downstream Segment for the years ended December 31, 2006, 2005 and 2004 (in thousands):

	For Year Ended December 31,			Increase (Decrease)	
	2006	2005	2004	2006-2005	2005-2004
Operating revenues:					
Sales of petroleum products	$ 5,800	$ —	$ —	$ 5,800	$ —
Transportation — Refined products	152,552	144,552	148,166	8,000	(3,614)
Transportation — LPGs	89,315	96,297	87,050	(6,982)	9,247
Other	56,634	46,342	44,184	10,292	2,158
Total operating revenues	304,301	287,191	279,400	17,110	7,791
Costs and expenses:					
Purchases of petroleum products	5,526	—	—	5,526	—
Operating expense	106,455	98,534	108,021	7,921	(9,487)
Operating fuel and power	38,354	32,500	31,706	5,854	794
General and administrative	17,085	17,653	16,884	(568)	769
Depreciation and amortization	41,405	39,403	43,135	2,002	(3,732)
Taxes — other than income taxes	8,437	11,097	8,917	(2,660)	2,180
Gains on sales of assets	(4,223)	(139)	(526)	(4,084)	387
Total costs and expenses	213,039	199,048	208,137	13,991	(9,089)
Operating income	91,262	88,143	71,263	3,119	16,880
Equity losses	(8,018)	(2,984)	(6,544)	(5,034)	3,560
Interest income	1,008	477	309	531	168
Other income — net	494	278	478	216	(200)
Earnings before interest	$ 84,746	$ 85,914	$ 65,506	$ (1,168)	$ 20,408

The following table presents volumes delivered in barrels and average tariff per barrel for the years ended December 31, 2006, 2005 and 2004 (in thousands, except tariff information):

	For Year Ended December 31,			Percentage Increase (Decrease)	
	2006	2005	2004	2006-2005	2005-2004
Volumes Delivered:					
Refined products	165,269	160,667	152,437	3%	5%
LPGs	44,997	45,061	43,982	—	2%
Total	210,266	205,728	196,419	2%	5%
Average Tariff per Barrel:					
Refined products (1)	$ 0.92	$ 0.90	$ 0.97	2%	(7%)
LPGs	1.98	2.14	1.98	(7%)	8%
Average system tariff per barrel	$ 1.15	$ 1.17	$ 1.20	(2%)	(3%)

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

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Effective November 1, 2006, we purchased a refined products terminal in Aberdeen, Mississippi, from MTMI. Through our TTMC subsidiary, we conduct distribution and marketing operations whereby we provide terminaling services for our throughput and exchange partners at this terminal. We also purchase refined products from our throughput partner that we in turn sell through spot sales at the Aberdeen truck rack to independent wholesalers and retailers of refined products. For the period ended December 31, 2006, sales related to these refined products marketing activities were $5.8 million and purchases of refined products for these activities were $5.5 million.

Revenues from refined products transportation increased $8.0 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to minor increases in refined products volumes transported and the refined products average rate per barrel. Volume increases were primarily due to increased demand for products supplied from the U.S. Gulf Coast into Midwest markets resulting from higher distillate price differentials and a greater demand for gasoline blendstocks, partially offset by unfavorable differentials for motor fuels during the first quarter of 2006. Additionally, refined products revenues increased due to increased terminaling activity at truck racks, including at our Shreveport terminal, which was placed in service in 2005, and higher product storage fees. The average tariff increased primarily due to an increase in gasoline blendstock deliveries, which have a higher tariff, and an increase in system tariffs, which went into effect in April and July 2006. The increase in the refined products average tariff rate was partially offset by the impact of Centennial on the average rates. When a larger proportion of the refined products deliveries are delivered under a Centennial tariff, TEPPCO's average tariff declines. Conversely, if the proportion of refined products deliveries moving under a Centennial origin decrease, the average TEPPCO tariff increases. Movements of refined products on Centennial therefore result in a decrease in the refined products average rate per barrel; however, utilizing Centennial for refined products movements allows us to transport incremental refined products and increase movements of long-haul propane volumes.

Revenues from LPGs transportation decreased $7.0 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, due to lower deliveries of propane in the upper Midwest and Northeast market areas as a result of warmer than normal winter weather in the first and fourth quarters of 2006, high propane prices and scheduled plant maintenance, known as a turnaround. Butane deliveries were below prior year levels due to a refinery turnaround during the fourth quarter of 2006. The LPGs average rate per barrel decreased from the prior year period primarily as a result of increased short-haul deliveries during the year ended December 31, 2006, compared with the year ended December 31, 2005.

Other operating revenues increased $10.3 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to a $5.3 million increase from increased storage revenue on assets acquired from Genco in July 2005 and an increase of $1.9 million in other system storage, a $2.1 million increase in refined products tender deduction revenues, additives and custody transfers fees, a $0.7 million increase in refined products loading fees and $0.4 million of higher RGP revenues on the northern portion of our Dean Pipeline.

Costs and expenses (excluding purchases of petroleum products) increased $8.4 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. Operating expenses increased $7.9 million primarily due to a $5.8 million increase in pipeline operating costs primarily as a result of acquisitions made in 2005; a $3.5 million increase in product measurement losses; $2.8 million in settlement charges related to the termination of our retirement cash balance plan (see Note 5 in the Notes to the Consolidated Financial Statements); $2.1 million of higher insurance premiums; a $1.5 million lower of cost or market adjustment on inventory (see Note 7 in the Notes to the Consolidated Financial Statements); $0.8 million of expenses relating to our special unitholder meeting; a $0.7 million increase in rental expense on a lease with a third-party pipeline and $0.6 million in severance expense as a result of the migration to a shared services environment with EPCO. These increases in costs and expenses were partially offset by a $3.4 million decrease in pipeline inspection and repair costs associated with our integrity management program, a $1.8 million decrease in accruals for employee vacations due to a change in the vacation policy in the current year period as a result of the migration to a shared services environment with EPCO; a $1.6 million decrease in labor and benefits expense primarily associated with incentive compensation plan vestings in the prior year period; a $1.1 million decrease due to regulatory penalties for past incidents; $0.6 million favorable insurance settlement for prior insurance claims; and $0.6 million decrease in accruals related to post employment liabilities associated with DEFS. Operating fuel and power increased $5.9 million primarily due to increased mainline throughput and higher power rates. Depreciation expense increased $2.0 million primarily due to assets placed into service, asset retirements in 2006 and the recording of a conditional asset retirement obligation as discussed below. Taxes – other than income taxes decreased $2.7 million primarily due to a true-up of property tax accruals for prior tax years and higher payroll taxes in the prior year period. General and administrative expenses decreased $0.6 million primarily due to a $1.5 million decrease in labor and benefits expense associated with prior year vesting provisions in our incentive compensation plans and decrease in accruals for employee vacations and $0.9 million in transition costs in the 2005 period due to the change in ownership of our General Partner, partially offset by a $1.1 million increase relating to the retirement of an executive in February 2006 and $0.7 million in severance expense as a result of the migration to a shared services environment with EPCO and higher executive compensation expense. During the years ended December 31, 2006 and 2005, we recognized net gains of $4.2 million and $0.1 million, respectively, from the sales of various assets in the Downstream Segment.

During 2006, we recorded $0.3 million of expense, included in depreciation and amortization expense, related to a conditional asset retirement obligation, and we recorded a $0.5 million liability, which represents the fair value of the conditional asset retirement obligation related to structural restoration work to be completed on leased office space that is required upon our anticipated office lease termination (see Note 8 in the Notes to the Consolidated Financial Statements).

Net losses from equity investments increased for the year ended December 31, 2006, compared with the year ended December 31, 2005, as shown below (in thousands):

	For Year Ended December 31,		Increase
	2006	2005	(Decrease)
Centennial	$ (17,094)	$ (10,727)	$ (6,367)
MB Storage	9,082	7,715	1,367
Other	(6)	28	(34)
Total equity losses	$ (8,018)	$ (2,984)	$ (5,034)

Equity losses in Centennial increased $6.4 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to lower transportation volumes and increased costs relating to pipeline inspection and repair costs associated with its integrity management program, partially offset by lower amortization expense on the portion of TE Products' excess investment in Centennial. Equity earnings in MB Storage increased $1.4 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to lower product measurement losses on the MB Storage system and higher revenues, partially offset by higher system maintenance expenses and higher operating fuel and power resulting from higher power rates and increased volumes.

For the years ended December 31, 2006 and 2005, TE Products received the first $1.7 million per quarter (or $6.78 million on an annual basis) of MB Storage's income before depreciation expense, as defined in the Agreement of Limited Partnership of MB Storage. TE Products' share of MB Storage's earnings may be adjusted annually by the partners of MB Storage. Any amount of MB Storage's annual income before depreciation expense in excess of $6.78 million is allocated evenly between TE Products and Louis Dreyfus. Depreciation expense on assets each party originally contributed to MB Storage is allocated between TE Products and Louis Dreyfus based on the net book value of the assets contributed. Depreciation expense on assets constructed or acquired by MB Storage subsequent to formation is allocated evenly between TE Products and Louis Dreyfus. For the years ended December 31, 2006 and 2005, TE Products' sharing ratios in the earnings of MB Storage were approximately 59.4% and 64.2%, respectively.

Interest income increased $0.5 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, due to higher interest income earned on cash investments and other investing activities.

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

Revenues from refined products transportation decreased $3.6 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Revenues from refined products transportation decreased primarily due to the recognition of $4.1 million of deferred revenue in 2004 related to the expiration of two customer transportation agreements. Under some of our transportation agreements with customers, the contracts specify minimum payments for transportation services. If the transportation services paid for are not used, the unused transportation service is recorded as deferred revenue. The contracts generally specify a subsequent period of time in which the customer can transport excess products to recover the amount recorded as deferred revenue.

During the third quarter of 2004, the time limit under two transportation agreements expired without the customers recovering the unused transportation services. As a result, we recognized the deferred revenue as refined products revenue in that period.

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

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

Revenues from refined products and LPGs were also impacted by Hurricanes Katrina and Rita, which affected the U.S. Gulf Coast in August and September 2005, respectively. Hurricane Katrina disrupted refineries and other pipeline systems in the central U.S. Gulf Coast, which provided us with additional deliveries at Shreveport and Arcadia, Louisiana, as shippers used alternative sources to supply product to areas where normal distribution patterns were disrupted. Hurricane Katrina also resulted in higher prices of refined products and LPGs, which had a negative impact on the current demand for the products. Hurricane Rita disrupted production at western U.S. Gulf Coast refineries, many of which directly supply us with product. Hurricane Rita also disrupted power to our Beaumont terminal, which resulted in the mainline being shut down for four days and Centennial being shut down for ten days. Our 230,000 barrel per day capacity, 20-inch diameter mainline system, which primarily delivers LPGs and gasoline from the Texas Gulf Coast to the Midwest, was pumping from MB Storage’s facility at approximately 60% of normal operating capacity until mid-October. Our 110,000 barrel per day capacity, 14-inch and 16-inch diameter pipelines, which primarily deliver distillates and gasoline from the Texas Gulf Coast to the Midwest, were pumping at approximately 75% of normal operating capacity from our Baytown, Texas, terminal until mid-October. We installed generators at our Beaumont, Texas, facility, which enabled receipt and delivery of refined products out of tankage at the terminal. Commercial power was restored to the Beaumont terminal and the Newton, Texas, pump station in mid-October and full operations were resumed. Centennial resumed operating at its normal capacity on October 1, 2005.

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

Costs and expenses (excluding purchases of petroleum products) decreased $9.0 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Operating expenses decreased $9.5 million primarily due to: a $15.1 million decrease in pipeline inspection and repair costs associated with our integrity management program as we neared completion of the first cycle of our integrity management program; a $2.0 million decrease in postretirement benefit accruals related to plan amendments (see Note 5 in the Notes to the Consolidated Financial Statements); a $2.1 million decrease in product measurement losses, and a $2.0 million decrease in legal expenses related to a legal settlement in 2004. These decreases to costs and expenses were partially offset by: a $2.9 million increase in labor and benefits expenses primarily associated with vesting provisions in certain of our compensation plans as a result of the change in ownership of our General Partner, higher labor expenses associated with an increase in the number of employees between years and higher incentive compensation expense as a result of improved operating performance; a $3.4 million increase in pipeline operating and maintenance expense; a $1.8 million increase attributable to regulatory penalties for past incidents; a $1.6 million increase in insurance expense; a $0.6 million increase in rental expense on a lease agreement from the Centennial pipeline capacity lease agreement, and an increase in other miscellaneous operating supplies expenses during the year, including a $0.4 million increase in environmental assessment and remediation expenses, a $0.3 million increase in labor and benefits expense related to retirement plan settlements with DEFS and hurricane related expenses.

Depreciation expense decreased $3.7 million primarily due to a $4.4 million non-cash impairment charge in the third quarter of 2004, partially offset by a $0.8 million write-off of assets related to the propane release and fire at a storage facility in Ohio (see Note 8 in the Notes to the Consolidated Financial Statements), assets placed into service and assets retired to depreciation expense in the 2005 period. Taxes – other than income taxes increased $2.2 million primarily due to asset acquisitions and a higher tax base in the 2005 period. Operating fuel and power expense increased $0.8 million primarily as a result of increased volumes and higher power rates during the 2005 period. General and administrative expenses increased $0.8 million primarily as a result of a $1.5 million increase related to transition costs due to the change in ownership of our General Partner and a $0.7 million increase in labor and benefits expenses primarily associated with vesting provisions in certain of our compensation plans as a result of the change in ownership of our General Partner, higher labor expenses associated with an increase in the number of employees between years and higher incentive compensation expense as a result of improved operating performance, partially offset by a $1.1 million decrease in consulting services primarily related to acquisition related activities in the 2004 period and a $0.6 million decrease in postretirement benefit accruals related to plan amendments (see Note 5 in the Notes to the Consolidated Financial Statements). During the year ended December 31, 2004, we recognized net gains of $0.5 million from the sales of various assets in the Downstream Segment.

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

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

Equity losses in Centennial decreased $3.7 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, primarily due to higher transportation revenues and volumes. Equity earnings in MB Storage decreased $0.2 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, primarily due to increased depreciation and amortization expense and higher general and administrative expenses, partially offset by higher rental and storage revenues and volumes. MB Storage was impacted by Hurricane Rita, which reduced revenues and increased operating expenses. Additionally, in April 2004, MB Storage acquired storage and pipeline assets and contracts for approximately $35.0 million, of which TE Products contributed $16.5 million. Increases in storage revenue, shuttle revenue, rental revenue and depreciation and amortization expense for year ended December 31, 2005, compared with the year ended December 31, 2004, are primarily related to the acquired storage assets and contracts.

For the year ended December 31, 2004, TE Products received the first $1.8 million per quarter (or $7.15 million on an annual basis) of MB Storage's income before depreciation expense. Any amount of MB Storage's annual income before depreciation expense in excess of $7.15 million for 2004 was allocated evenly between TE Products and Louis Dreyfus. For the year ended December 31, 2004, TE Products' sharing ratio in the earnings of MB Storage was approximately 69.4%.

Upstream Segment

The following table provides financial information for the Upstream Segment for the years ended December 31, 2006, 2005 and 2004 (in thousands):

	For Year Ended December 31,			Increase (Decrease)	
	2006	2005	2004	2006-2005	2005-2004
Operating revenues: (1)					
Sales of petroleum products (2) (3)	$ 9,060,782	$ 8,062,131	$ 5,426,832	$ 998,651	$ 2,635,299
Transportation — Crude oil	38,822	37,614	37,177	1,208	437
Other	10,025	10,494	11,986	(469)	(1,492)
Total operating revenues	9,109,629	8,110,239	5,475,995	999,390	2,634,244
Costs and expenses: (1)					
Purchases of petroleum products (2) (3)	8,953,407	7,989,682	5,370,234	963,725	2,619,448
Operating expense	54,422	52,808	45,990	1,614	6,818
Operating fuel and power	6,989	5,122	5,490	1,867	(368)
General and administrative	5,986	7,077	5,434	(1,091)	1,643
Depreciation and amortization	14,400	17,161	13,130	(2,761)	4,031
Taxes — other than income taxes	5,390	5,333	3,979	57	1,354
Gains on sales of assets	(1,805)	(118)	(527)	(1,687)	409
Total costs and expenses	9,038,789	8,077,065	5,443,730	961,724	2,633,335
Operating income	70,840	33,174	32,265	37,666	909
Equity earnings	11,905	23,078	28,692	(11,173)	(5,614)
Interest income	407	—	43	407	(43)
Other income — net	388	156	363	232	(207)
Earnings before interest	$ 83,540	$ 56,408	$ 61,363	$ 27,132	$ (4,955)

(1) Amounts in this table are presented after elimination of intercompany transactions, including sales and purchases of petroleum products.

(2) Petroleum products includes crude oil, lubrication oils and specialty chemicals.

(3) Amounts for the period from April 1, 2006 through December 31, 2006 have been fully adjusted for the impact of adopting Emerging Issues Task Force ("EITF") 04-13. The period from January 1, 2006 through March 31, 2006 and the 2005 and 2004 periods have not been adjusted for the adoption of EITF 04-13, as retroactive restatement was not permitted, which impacts comparability (for further discussion, see below).

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 years ended December 31, 2006, 2005 and 2004 is presented below (in thousands, except per barrel and per gallon amounts):

	For Year Ended December 31, 2006	2005	2004	Percentage Increase (Decrease) 2006-2005	2005-2004
Margins: (1)					
Crude oil marketing	$ 58,358	$ 30,597	$ 22,468	91%	36%
Lubrication oil sales	8,565	7,455	6,494	15%	15%
Revenues: (1)					
Crude oil transportation	67,439	61,611	55,425	9%	11%
Crude oil terminaling	11,835	10,400	9,388	14%	11%
Total margin/revenues	$ 146,197	$ 110,063	$ 93,775	33%	17%
Total barrels/gallons:					
Crude oil marketing (barrels) (1)	222,069	203,325	177,273	9%	15%
Lubrication oil volume (gallons)	14,444	14,844	13,964	(3%)	6%
Crude oil transportation (barrels)	91,487	94,743	101,462	(3%)	(7%)
Crude oil terminaling (barrels)	125,974	110,254	113,197	14%	(3%)
Margin per barrel or gallon:					
Crude oil marketing (per barrel) (1)	$ 0.263	$ 0.150	$ 0.127	75%	18%
Lubrication oil margin (per gallon)	0.593	0.502	0.465	18%	8%
Average tariff per barrel:					
Crude oil transportation	$ 0.737	$ 0.650	$ 0.546	13%	19%
Crude oil terminaling	0.094	0.094	0.083	—	13%

(1) Amounts in this table are presented prior to the eliminations of intercompany sales, revenues and purchases between TCO and TCPL. 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 in the statements of income in Note 15 in the Notes to the Consolidated Financial Statements (in thousands):

	For Year Ended December 31, 2006	2005	2004
Sales of petroleum products	$ 9,060,782	$ 8,062,131	$ 5,426,832
Transportation — Crude oil	38,822	37,614	37,177
Less: Purchases of petroleum products	(8,953,407)	(7,989,682)	(5,370,234)
Total margin/revenues	146,197	110,063	93,775
Other operating revenues	10,025	10,494	11,986
Net operating revenues	156,222	120,557	105,761
Operating expense	54,422	52,808	45,990
Operating fuel and power	6,989	5,122	5,490
General and administrative expense	5,986	7,077	5,434
Depreciation and amortization	14,400	17,161	13,130
Taxes — other than income taxes	5,390	5,333	3,979
Gains on sales of assets	(1,805)	(118)	(527)
Operating income	$ 70,840	$ 33,174	$ 32,265

On April 1, 2006, we adopted EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (see Note 3 in the Notes to the Consolidated Financial Statements), which resulted in crude oil inventory purchases and sales under buy/sell transactions, which were previously recorded as gross purchases and sales, to be treated as inventory exchanges in our statements of consolidated income. EITF 04-13 reduced gross revenues and purchases, but did not have a material effect on our financial position, results of operations or cash flows. Under the consensus reached in EITF 04-13, buy/sell transactions are reported as non-monetary exchanges and consequently not presented on a gross basis in our statements of consolidated income. Implementation of EITF

04-13 reduced revenues and purchases of petroleum products on our statements of consolidated income by approximately $1,127.6 million for the period from April 1, 2006 through December 31, 2006. The revenues and purchases of petroleum products associated with buy/sell transactions that are reported on a gross basis in our statements of consolidated income for the period from January 1, 2006 through March 31, 2006 and for the years ended December 31, 2005 and 2004, are approximately $275.4 million, $1,405.7 million and $496.1 million, respectively. Under the provisions of the consensus, retroactive restatement of buy/sell transactions reported in prior periods was not permitted.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Sales of petroleum products increased $998.7 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. Purchases of petroleum products increased $963.7 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. The supplemental financial data accompanying our earnings release dated February 6, 2007 included unaudited estimates of revenues for sales of petroleum products and costs for purchases of petroleum products for the quarter ended December 31, 2006, of $2,613.2 million and $2,586.6 million, respectively, and for the year ended December 31, 2006, of $9,743.5 million and $9,630.1 million, respectively, that were each revised downward subsequent to our 2006 earnings release by $663.0 million. This revision had no effect on our operating income or net income included in the earnings release. The financial information included in this Report reflects the adjusted amounts for sales and purchases of petroleum products. Operating income increased $37.7 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. The increases in sales and purchases were primarily a result of an increase in the price of crude oil and increased volumes marketed, partially offset by the effect of the adoption of EITF 04-13, which reduced each of revenues and purchases of petroleum products by $1,127.6 million for the period from April 1, 2006 through December 31, 2006. The average NYMEX price of crude oil was $66.23 per barrel for the year ended December 31, 2006, compared with $56.65 per barrel for the year ended December 31, 2005. The increase in the average price of crude oil, partially offset by increased purchases and costs and expenses discussed below, were the primary factors resulting in an increase in operating income. Crude oil marketing margin increased $27.8 million (approximately $4.9 million of which is attributable to intercompany transactions between TCO and TCPL) primarily due to favorable market conditions and increased volumes marketed, partially offset by increased transportation costs. Crude oil transportation revenues (prior to intercompany eliminations) increased $5.8 million primarily due to higher revenues on our Red River and West Texas systems related to movements on higher tariff segments and revenues from acquisitions in 2005 and increased transportation volumes and revenues on our South Texas system, partially offset by decreases in transportation volumes on lower tariff segments of our Basin and Red River systems. Crude oil terminaling revenues increased $1.4 million as a result of increased pumpover volumes at Midland, Texas and Cushing, Oklahoma. Lubrication oil sales margin increased $1.1 million due to an increase in sales of fuel and lubrication oil volumes that have a higher average margin per gallon than in the prior year period, partially offset by a decrease in other sales volumes.

Other operating revenues decreased $0.5 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to a $1.5 million favorable settlement of inventory imbalances in the first quarter of 2005, partially offset by higher revenues from documentation and other services to support customers' trading activity at Midland and Cushing.

Costs and expenses, excluding expenses associated with purchases of petroleum products, decreased $2.0 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. Depreciation and amortization expense decreased $2.8 million primarily due to $2.6 million of asset impairments and asset retirements during the prior year period. During the year ended December 31, 2006, we recognized gains of $1.8 million primarily on the sale of idled crude pipeline assets to Enterprise (see Note 11 in the Notes to the Consolidated Financial Statements). General and administrative expenses decreased $1.1 million from the prior year period primarily due to a $1.4 million decrease in labor and benefits expense as a result of higher labor and benefits costs in the prior year period associated with vesting provisions in certain of our incentive compensation plans and the change in ownership of our General Partner, which resulted in higher incentive compensation expenses for that period and a $0.5 million decrease in accruals for employee vacations due to a change in the vacation policy in the current year period as a result of the migration to a shared services environment with EPCO, partially offset by $0.4 million in severance expense as a result of the migration to a shared services environment with EPCO and $0.3 million in settlement charges related to the termination of our retirement cash balance plan (see Note 5 in the

Notes to the Consolidated Financial Statements). Operating fuel and power increased $1.9 million primarily as a result of increased power rates in the 2006 period, partially offset by lower transportation volumes. Operating expenses increased $1.6 million from the prior year period, primarily due to a $1.5 million increase in environmental assessment and remediation costs, $1.5 million of higher insurance premiums, a $0.9 million increase as a result of product measurement losses and higher crude oil prices, a $0.9 million increase in pipeline operating and maintenance expenses, $0.6 million in settlement charges related to the termination of our retirement cash balance plan and $0.4 million in severance expense as a result of the migration to a shared services environment with EPCO. These increases in operating expenses were partially offset by a $1.4 million decrease in accruals for employee vacations, a $1.1 million decrease in labor and benefits expense related to vesting provisions in certain of our compensation plans in the prior year period as a result of the change in ownership of our General Partner, a $0.8 million favorable insurance settlement, a $0.5 million decrease in costs associated with our integrity management program and a $0.4 million decrease in expense related to adjustments to the workers compensation accrual. Taxes – other than income taxes increased $0.1 million due to increases in property tax accruals and a higher property asset base in 2006.

Equity earnings from our investment in Seaway decreased $11.2 million for year ended December 31, 2006, compared with the year ended December 31, 2005. Our sharing ratio for 2005 was 60%, while for the full year of 2006, it was 47% of the revenue and expense of Seaway (see Note 9 in the Notes to the Consolidated Financial Statements). Equity earnings from our investment in Seaway also decreased due to higher operating, general and administrative expenses related to pipeline integrity costs for the corrective measures taken for the pipeline release in May 2005, increased environmental remediation and assessment costs, higher operating fuel and power costs relating to the use of a drag reducing agent and higher power rates, a favorable settlement in the first quarter of 2005 with a former owner of Seaway's crude oil assets regarding inventory imbalances that were not acquired by us and decreased transportation volumes. Long-haul volumes on Seaway averaged 242,000 barrels per day during the year ended December 31, 2006, compared with 271,000 barrels per day during the year ended December 31, 2005. Fourth quarter 2005 long-haul transportation volumes were higher due in part to Hurricane Katrina, which affected the U.S. Gulf Coast in 2005.

After Seaway's pipeline release in May 2005, the maximum operating pressure on the pipeline system was reduced by 20% until the cause of the failure was determined. Corrective measures were implemented upon the release in 2005 and were completed during the second quarter of 2006. Seaway operated at reduced maximum pressure through May 2006. On June 1, 2006, Seaway's operating pressure was increased to 100%. As a result of operating at reduced maximum pressure, we used a drag reducing agent to increase the flow of product through the pipeline system during the period when operating pressures were reduced. The drag reducing agent allowed us to maintain the higher volumes transported, but also increased our operating costs. The reduced pressure did not have a material adverse effect on our financial position, results of operations or cash flows (see Note 18 in the Notes to the Consolidated Financial Statements).

Interest income increased $0.4 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, due to higher interest income earned on cash investments and other investing activities.

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

Sales of petroleum products increased $2,635.3 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Purchases of petroleum products increased $2,619.4 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Operating income increased $0.9 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. The increases in sales and purchases were primarily a result of an increase in the price of crude oil and increased volumes marketed. The average NYMEX price of crude oil was $56.65 per barrel for the year ended December 31, 2005, compared with $41.42 per barrel for the year ended December 31, 2004. The increase in the average price of crude oil, partially offset by increased purchases and costs and expenses discussed below, were the primary factors resulting in an increase in operating income. Crude oil marketing margin increased $8.1 million (approximately $5.7 million of which is attributable to intercompany transactions between TCO and TCPL) primarily due to increased volumes marketed primarily due to asset acquisitions, partially offset by increased transportation costs. Crude oil transportation revenues (prior to intercompany eliminations) increased $6.2 million primarily due to increased transportation volumes and revenues on our South Texas system due to the acquisition of crude oil pipeline assets in

April 2005 and higher revenues on our West Texas systems resulting from organic growth projects and benefits realized from assets acquired at Cushing. The average transportation tariff per barrel increased 19% primarily due to movements of volumes on higher tariff segments, including higher tariffs on the assets acquired from BP Pipelines (North America) Inc. ("BP") in April 2005. Lubrication oil sales margin increased $1.0 million due to increased sales of lubrication oils and chemicals and the acquisitions of lubrication oil distributors in Casper, Wyoming, in August 2004, and in Dumas, Texas, in August 2005. Crude oil terminaling revenues increased $1.0 million as a result of increased pumpover volumes at Cushing, Oklahoma, partially offset by decreased pumpover volumes at Midland, Texas.

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

Costs and expenses, excluding expenses associated with purchases of petroleum products, increased $13.9 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Operating expenses increased $6.8 million from the prior year period as a result of: a $4.8 million increase in pipeline operating and maintenance expense primarily due to acquisitions and the continued integration of the assets acquired in 2003 from Genesis Crude Oil, L.P. and Genesis Pipeline Texas, L.P. into our system; a $1.8 million increase in labor and benefits expense related to vesting provisions in certain of our compensation plans as a result of the change in ownership of our General Partner, an increase in the number of employees between periods, and higher incentive compensation expense as a result of improved operating performance; a $1.7 million increase in insurance expense; a $1.0 million settlement of an indemnity related to a past acquisition; a $0.3 million increase in transition charges as a result of the change in ownership of our General Partner; a $0.7 million increase in bad debt expense primarily related to a customer nonpayment; a $0.4 million increase in operating costs for our undivided ownership interest in Basin Pipeline, and increases in miscellaneous operating supplies and expenses. These increases were partially offset by a $2.3 million decrease in product measurement losses, a $1.9 million decrease in pipeline inspection and repair costs associated with our integrity management program and a $1.2 million decrease in environmental assessment and remediation costs. Depreciation and amortization expense increased $4.0 million primarily as a result of a $2.6 million non-cash impairment charge in the third quarter of 2005, resulting from the impairment of two crude oil systems (see Note 8 in the Notes to the Consolidated Financial Statements). Depreciation expense also increased as a result of assets placed in service and assets retired to depreciation expense during the period. General and administrative expenses increased $1.6 million from the prior year period primarily due to a $0.9 million increase in labor and benefits expense related to vesting provisions in certain of our compensation plans as a result of the change in ownership of our General Partner, an increase in the number of employees between periods, and higher incentive compensation expense as a result of improved operating performance, a $0.4 million increase in transition charges as a result of the change in ownership of our General Partner and a $0.3 million increase related to a legal settlement. Taxes – other than income taxes increased $1.4 million due to asset acquisitions and a higher asset base in the 2005 period. During the year ended December 31, 2004, we recognized a gain of $0.4 million from the sale of our remaining interest in the original Rancho Pipeline system. Operating fuel and power decreased $0.4 million primarily as a result of lower transportation volumes in 2005.

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

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Midstream Segment

The following table provides financial information for the Midstream Segment for the years ended December 31, 2006, 2005 and 2004 (in thousands):

	For Year Ended December 31,			Increase (Decrease)	
	2006	2005	2004	2006-2005	2005-2004
Operating revenues:					
Sales of petroleum products	$ 18,766	$ —	$ —	$ 18,766	$ —
Gathering — Natural gas (1)	123,933	152,797	140,122	(28,864)	12,675
Transportation — NGLs	43,838	43,915	41,204	(77)	2,711
Other	14,732	14,459	14,576	273	(117)
Total operating revenues	201,269	211,171	195,902	(9,902)	15,269
Costs and expenses: (1)					
Purchases of petroleum products	17,272	—	—	17,272	—
Operating expense	42,887	34,758	37,882	8,129	(3,124)
Operating fuel and power	12,107	11,350	10,943	757	407
General and administrative expense	8,277	8,413	5,698	(136)	2,715
Depreciation and amortization	52,447	54,165	56,019	(1,718)	(1,854)
Taxes — other than income taxes	4,156	4,180	4,444	(24)	(264)
Gains on sales of assets	(1,376)	(411)	—	(965)	(411)
Total costs and expenses	135,770	112,455	114,986	23,315	(2,531)
Operating income	65,499	98,716	80,916	(33,217)	17,800
Equity earnings (1)	35,052	—	—	35,052	—
Interest income	662	210	115	452	95
Other income — net	6	14	12	(8)	2
Earnings before interest	$ 101,219	$ 98,940	$ 81,043	$ 2,279	$ 17,897

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah was deconsolidated and operating results, including revenues and costs and expenses, after August 1, 2006 are included in equity earnings (see Note 9 in the Notes to the Consolidated Financial Statements).

The following table presents volume and average rate information for the years ended December 31, 2006, 2005 and 2004 (in thousands, except average fee and average rate amounts):

	For Year Ended December 31,			Percentage Increase (Decrease)	
	2006	2005	2004	2006-2005	2005-2004
Gathering — Natural Gas — Jonah: (1)					
MMcf	472,868	415,181	354,546	14%	17%
BBtus	521,723	458,159	392,154	14%	17%
Average fee per MMBtu	$ 0.203	$ 0.188	$ 0.194	8%	(3%)
Gathering — Natural Gas — Val Verde:					
MMcf	181,928	180,699	144,539	1%	25%
BBtus	160,929	159,398	122,706	1%	30%
Average fee per MMBtu	$ 0.406	$ 0.418	$ 0.523	(3%)	(20%)
Transportation — NGLs:					
Thousand barrels	69,746	61,051	59,549	14%	3%
Average rate per barrel	$ 0.629	$ 0.719	$ 0.692	(13%)	4%
Natural Gas Sales:					
BBtu	10,206	—	—	—	—
Average fee per MMBtu	$ 4.984	$ —	$ —	—	—
Fractionation — NGLs:					
Thousand barrels	4,406	4,431	4,149	(1%)	7%
Average rate per barrel	$ 1.662	$ 1.747	$ 1.797	(5%)	(3%)
Sales — Condensate: (1)					
Thousand barrels	87.6	62.1	84.4	41%	(26%)
Average rate per barrel	$ 61.42	$ 52.21	$ 37.99	18%	37%

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah was deconsolidated and operating results after August 1, 2006 are included in equity earnings (see Note 9 in the Notes to the Consolidated Financial Statements). However, the table includes Jonah's volume and average rate information for the full years ended December 31, 2006, 2005 and 2004.

Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah, the partnership through which we own an interest in the Jonah system, was deconsolidated and has been subsequently accounted for as an equity investment. Through July 31, 2006, Jonah's operating results were fully consolidated in the Midstream Segment operating results. Beginning August 1, 2006, Jonah has been accounted for as an equity investment and operating results for Jonah for the period August 1, 2006 through December 31, 2006, are reported as equity earnings. For the period from August 1, 2006 through December 31, 2006, our sharing in the earnings of Jonah was approximately 99.7%.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Revenues from the gathering of natural gas decreased $28.9 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. Natural gas gathering revenues from the Jonah system decreased $37.9 million due to the deconsolidation of Jonah on August 1, 2006, partially offset by an increase of $10.4 million primarily due to the Phase IV expansion of the Jonah system completed in February 2006, prior to deconsolidation. For the full year ended December 31, 2006, Jonah's gathering volumes averaged 1.3 Bcf per day, compared with 1.2 Bcf per day for the year ended December 31, 2005. Jonah's volumes gathered increased 57.7 Bcf for the year ended December 31, 2006, primarily as a result of the Phase IV expansion, compared with the year ended December 31, 2005. Jonah's average natural gas gathering rate per MMBtu increased 8% primarily due to lower system wellhead pressures. Natural gas gathering revenues from the Val Verde system decreased $1.4 million for the year ended December 31, 2006, primarily due to the natural decline of coal bed methane production in the fields in which the Val Verde gathering system operates. For the year ended December 31, 2006, Val Verde's gathering volumes averaged 498 MMcf per day, compared with 495 MMcf per day for the year ended December 31, 2005. Val Verde's volumes gathered increased 1.2 Bcf primarily due to increased volumes from a natural gas connection that occurred in December 2004 on the Val Verde system. Val Verde's average natural gas gathering rate per MMBtu decreased 3% primarily due to newer contracts that have lower rates than the previous year's average rates on Val Verde.

In May 2006, we began to aggregate purchases of wellhead gas on Jonah and re-sell the aggregated quantities at key Jonah delivery points in order to facilitate throughput on the system. The purchases and sales are generally contracted to occur in the same month to minimize price risk. During the second quarter of 2006, gas purchase and sales contracts were finalized and executed, and the marketing of gas on the Jonah system began. Sales from petroleum products relating to the natural gas marketing activities were $18.8 million and purchases of petroleum products were $17.3 million for the period from January 1, 2006, through July 31, 2006. Effective August 1, 2006, with the deconsolidation of Jonah, sales and purchases of natural gas are reported in equity earnings.

Revenues from the transportation of NGLs decreased $0.1 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to a decrease in the average NGL transportation rate per barrel as a result of increased short-haul movements on the Chaparral Pipeline and a lower average rate per barrel on the Panola Pipeline. During the 2006 period, volumes of NGLs transported increased due to increases on the Chaparral, Panola and Dean Pipelines, partially offset by decreased volumes transported on the Wilcox and San Jacinto Pipelines.

Other operating revenues increased $0.3 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. Other operating revenues increased $1.7 million on the Panola Pipeline and $1.2 million on the Chaparral Pipeline primarily due to new pipeline capacity leases. Other operating revenues on Jonah decreased $1.5 million due to the deconsolidation of Jonah on August 1, 2006, partially offset by an increase of $0.6 million due to higher condensate sales. These increases were partially offset by a $1.3 million decrease in Val Verde's other operating revenue as a result of contractual producer minimum fuel levels exceeding actual operating fuel usage. Val Verde retains a portion of its producers' gas to compensate for fuel used in operations. The actual usage of gas can differ from the amount contractually retained from producers. Value retained from producers or sales generated as a result of efficient fuel usage are recognized as other operating revenues. Average commodity prices decreased by approximately $2.50 per MMBtu from the 2005 period while fuel usage increased slightly. Value retained from producers as a result of efficient fuel usage are recognized as other operating revenues. Other operating revenues also decreased $0.4 million due to a decrease in fractionation revenues due to lower volumes during the 2006 period.

Costs and expenses, excluding purchases of petroleum products, increased $6.0 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. Operating expenses increased $8.1 million primarily due to a $4.3 million increase related to imbalance valuations on Val Verde and Chaparral, a $4.3 million increase in expense as a result of the migration to a shared services environment with EPCO, a $1.4 million increase in expense associated with the formation of the joint venture with Enterprise and costs related to the special unitholder meeting and a $1.2 million increase in other pipeline operating and maintenance expense, partially offset by a $3.0 million decrease due to the deconsolidation of Jonah on August 1, 2006. Operating fuel and power increased $0.8 million primarily due to higher transportation volumes and power rates. Depreciation and amortization expense decreased $1.7 million primarily due to a $3.6 million decrease in amortization expense and a $1.2 million decrease in depreciation expense from the deconsolidation of Jonah, partially offset by a $2.2 million increase in amortization expense on Val Verde as a result of a decrease in the estimated life of intangible assets under the units-of-production method and a $0.7 million increase on Val Verde due to accretion expense on conditional asset retirement obligations (as discussed below). General and administrative expenses decreased $0.2 million primarily due to lower transition and finance costs from the prior year, partially offset by an increase of $0.6 million in severance expense as a result of the migration to a shared services environment with EPCO and higher legal costs. During the years ended December 31, 2006 and 2005, gains of $1.4 million and $0.4 million, respectively, were recognized on the sales of various equipment at Val Verde.

During 2006, we recorded $0.3 million of expense included in depreciation and amortization expense, related to conditional asset retirement obligations. Additionally, we have recorded a $0.7 million liability, which represents the fair value, of the conditional asset retirement obligations related to the retirement of our Val Verde gathering system. During 2006, we assigned probabilities for settlement dates and settlement methods for use in an expected present value measurement of fair value and recorded asset retirement obligations.

Equity earnings of $35.0 million in 2006 were from our ownership interest in the Jonah joint venture with an affiliate of Enterprise, which was formed effective August 1, 2006. Beginning August 1, 2006, revenues and costs and expenses of Jonah are now included in equity earnings based upon our ownership interest in Jonah. Prior to August 1, 2006, Jonah was wholly-owned, and its revenues and costs and expenses were included in the individual revenues and costs and expenses line items. For the period from August 1, 2006 through December 31, 2006, our sharing in the revenues and costs and expenses of Jonah was 99.7%. Had the revenues and costs and expenses from Jonah for the twelve months ended December 31, 2006 and 2005, been accounted for under the same method in both periods, operating results from Jonah would have increased $30.5 million in the 2006 period, compared with the prior year period, primarily due to increased volumes generated from completion of Phase IV of the Jonah expansion project and increased revenues generated from the completion of a portion of Phase V of the expansion project in December 2005.

Interest income increased $0.4 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, due to higher interest income earned on cash investments and other investing activities.

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

Revenues from the gathering of natural gas increased $12.7 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Natural gas gathering revenues from the Jonah system increased $10.2 million and volumes gathered increased 60.6 Bcf for the year ended December 31, 2005, primarily due to the expansion of the Jonah system in 2004. Installation of additional capacity of 100 MMcf per day was completed during the fourth quarter of 2004. For the year ended December 31, 2005, Jonah's gathering volumes averaged 1.2 Bcf per day, compared with 1.0 Bcf per day for the year ended December 31, 2004. Jonah's average natural gas gathering rate per MMcf decreased due to higher system wellhead pressures. Natural gas gathering revenues from the Val Verde system increased $2.5 million and volumes gathered increased 36.7 Bcf for the year ended December 31, 2005, primarily due to increased volumes from two new connections made to the Val Verde system in May and December 2004, partially offset by the natural decline of CBM production. For the year ended December 31, 2005, Val Verde's gathering volumes averaged 495 Mcf per day, compared with 395 Bcf per day for the year ended December 31, 2004. Val Verde's average natural gas gathering rate per MMcf decreased due to contracts entered into relating to the new connections, which have lower rates than the existing Val Verde system's average rates.

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

Other operating revenues decreased $0.1 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Val Verde's other operating revenues increased $0.8 million due to revenues generated as a result of contractual producer minimum fuel levels exceeding actual operating fuel usage during 2005. NGL fractionation revenues increased $0.3 million as a result of higher volumes. Other operating revenues on Chaparral decreased $1.6 million primarily due to the recognition of deferred revenue related to an inventory settlement in the prior year period.

Costs and expenses decreased $2.5 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Operating expenses decreased $3.1 million from the prior year period as a result a $6.0 million decrease in gas settlement expenses, a $3.3 million decrease in a operating expenses primarily related to Val Verde and a $0.5 million decrease in inspection and repair costs associated with our integrity management program, partially offset by a $3.1 million increase in labor and benefits expense primarily associated with vesting provisions in certain of our compensation plans and with certain DEFS employees becoming employees of EPCO (see Note 5 in the Notes to the Consolidated Financial Statements), a $2.5 million increase in operating expense on Jonah and a $1.5 million increase in insurance expense. Amortization expense on the Jonah system decreased $2.6 million primarily due to a $3.9 million decrease related to revisions to the estimated life of intangible assets under the units-of-production method, partially offset by a $1.3 million increase as a result of higher volumes in 2005. Amortization expense on the Val Verde system increased $1.4 million primarily due to a $2.4 million increase related to revisions to the estimated life of intangible assets under the units-of-production method, partially offset by a $1.0 million decrease as a result of lower volumes in 2005 on contracts included in the intangible assets, resulting from the natural decline in CBM production. Depreciation expense decreased $0.7 million primarily due to a $3.1 million decrease on Jonah as a result of increases to the estimated lives of Jonah's assets, partially offset by a $1.4 million increase on Val Verde as a result of assets placed into service in 2004 and a $1.0 million increase on the NGL pipelines as a result of assets placed into service and adjustments to asset lives. Taxes – other than income taxes decreased $0.3 million as a result of adjustments to property tax accruals. General and administrative expenses increased $2.7 million primarily due to a $1.9 million increase in labor and benefits expense primarily associated with vesting provisions in certain of our compensation plans and with certain DEFS employees becoming employees of EPCO and a $1.0 million increase in transition expenses as a result of the change in ownership of our General Partner. Operating fuel and power increased $0.4 million compared to the prior year due to adjustments to the fuel and power accrual in the prior year period, partially offset by increased expenses in 2005 related to higher transportation volumes. A net gain of $0.4 million was recognized on the sale of equipment in the 2005 period.

Discontinued Operations

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

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the years ended December 31, 2006, 2005 and 2004, are presented below (in thousands):

	For Year Ended December 31,		
	2006	2005	2004
Operating revenues:			
Sales of petroleum products	$ 3,828	$ 10,479	$ 7,295
Other	932	2,975	2,807
Total operating revenues	4,760	13,454	10,102
Costs and expenses:			
Purchases of petroleum products	3,000	8,870	5,944
Operating expense	182	692	738
Depreciation and amortization	51	612	610
Taxes — other than income taxes	30	130	121
Total costs and expenses	3,263	10,304	7,413
Income from discontinued operations	$ 1,497	$ 3,150	$ 2,689

Sales of petroleum products less purchases of petroleum products resulting from the processing activities at the Jonah Pioneer plant decreased $0.8 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to the sale of the Pioneer plant on March 31, 2006, partially offset by increased NGL prices. The Pioneer gas processing plant was completed during the first quarter of 2004, as a part of Jonah's Phase III expansion to increase the processing capacity in southwestern Wyoming. Pioneer's processing agreements allowed the producers to elect annually whether to be charged under a fee-based arrangement or a fee plus keep-whole arrangement. Under the fee-based election, Jonah received a fee for its processing services. Under the fee plus keep-whole election, Jonah received a lower fee for its processing services, retained and sold the NGLs extracted during the process and delivered to producers the residue gas equivalent in energy to the natural gas received from the producers. Jonah sold the NGLs it retained and purchased gas to replace the equivalent energy removed in the liquids. For the 2005 and 2006 periods, the producers elected the fee plus keep-whole arrangement.

Interest Expense and Capitalized Interest

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Interest expense increased $8.2 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to higher outstanding borrowings and higher short term floating interest rates on our revolving credit facility, partially offset by reductions in interest expense during 2006 related to our interest rate swaps and $2.0 million of interest expense recognized in the 2005 period related to the termination of a treasury lock (see Note 6 in the Notes to the Consolidated Financial Statements).

Capitalized interest increased $3.9 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, due to higher construction work-in-progress balances in 2006 as compared to the 2005 period as well as construction of the Phase V expansion project during 2006 related to our investment in Jonah.

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

Interest expense increased $12.3 million for the year ended December 31, 2005, compared with the year ended December 31, 2004, primarily due to higher outstanding borrowings and higher short term floating interest rates on our revolving credit facility and $2.0 million of expense related to the termination of a treasury lock. These increases were partially offset by a higher percentage of fixed interest rate debt during the year ended December 31, 2004, that carried a higher rate of interest as compared with floating interest rate debt. The higher percentage of fixed interest rate debt resulted from an interest rate swap that expired in April 2004 (see Note 6 in the Notes to the Consolidated Financial Statements).

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

Deferred Income Tax Expense — Texas Margin Tax

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

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

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

The base used to compute the Texas Margin Tax affects book-tax differences. All effects of a tax law change are accounted for in the period of the law's enactment. A change in tax status that results from a change in tax law is recognized on the enactment date and the effect of recognizing a deferred tax liability or asset is included in income from continuing operations. Therefore, we have calculated and recorded an estimated deferred tax liability of approximately $0.7 million using the enacted tax rate expected to apply to taxable income in the periods in which the deferred tax liability is expected to be realized or settled. The non-cash offsetting charge is shown on our statements of consolidated income as deferred income tax expense for the year ended December 31, 2006.

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

Financial Condition and Liquidity

Cash generated from operations, credit facilities and debt and equity offerings are our primary sources of liquidity. At December 31, 2006 and 2005, we had working capital deficits of $9.8 million and $38.1 million, respectively. At December 31, 2006, we had approximately $201.3 million in available borrowing capacity under our revolving credit facility to cover any working capital needs. Cash flows for the years ended December 31, 2006, 2005 and 2004 were as follows (in millions):

	For Year Ended December 31,		
	2006	2005	2004
Cash provided by (used in):			
Operating activities	$ 273.1	$ 254.5	$ 267.2
Investing activities	(273.7)	(350.9)	(190.2)
Financing activities	0.6	80.1	(90.1)

Operating Activities

Net cash from operating activities for the years ended December 31, 2006, 2005 and 2004, was comprised of the following (in millions):

	For Year Ended December 31,		
	2006	2005	2004
Net income	$ 202.1	$ 162.6	$ 138.5
Income from discontinued operations	(19.4)	(3.2)	(2.7)
Deferred income tax expense	0.7	—	—
Depreciation and amortization	108.3	110.7	112.3
Earnings in equity investments	(36.8)	(20.1)	(22.1)
Distributions from equity investments	63.5	37.1	47.2
Gains on sales of assets	(7.4)	(0.7)	(1.1)
Non-cash portion of interest expense	1.7	1.6	(0.4)
Cash used in working capital and other	(41.1)	(37.3)	(7.8)
Net cash provided by continuing operating activities	271.6	250.7	263.9
Cash flows from discontinued operations	1.5	3.8	3.3
Net cash provided by operating activities	$ 273.1	$ 254.5	$ 267.2

Net cash provided by continuing operating activities increased $20.9 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to an increase of $26.4 million in distributions received from our equity investments in Seaway, MB Storage and Jonah and due to the timing of cash receipts and cash disbursements for other working capital components, partially offset by an increase of $46.3 million in crude oil inventory (as discussed below). Net cash provided by continuing operating activities decreased $13.2 million for the year ended December 31, 2005, compared with the year ended December 31, 2004. Cash distributions from equity investments decreased $10.1 million for the year ended December 31, 2005, primarily due to Seaway funding its construction of additional storage tanks from its operating cash flows. Cash used for working capital purposes increased $29.4 million for the year ended December 31, 2005, primarily due to the timing of cash disbursements and cash receipts for crude oil inventory. For a discussion of changes in earnings before interest, depreciation and amortization expense, equity earnings, income from discontinued operations and consolidated interest expense – net, see Results of Operations for the Downstream Segment, Upstream Segment and Midstream Segment in Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

As part of our crude oil marketing activity, we purchase crude oil and simultaneously enter into offsetting sales contracts for physical delivery in future periods. The result of these transactions is an increase in the amount of inventory carried on our books until the crude oil is sold. As of December 31, 2006, these transactions and other crude oil operating inventory changes represented a $46.3 million increase in the amount of inventory recorded on our consolidated balance sheet as compared to December 31, 2005. The substantial majority of inventory related to these contracts as of December 31, 2006, has been contracted for sale in the first quarter of 2007; however, new contracts may be executed, resulting in higher inventory balances being held at future balance sheet periods.

Net cash from operating activities for the years ended December 31, 2006, 2005 and 2004, included interest payments, net of amounts capitalized, of $88.1 million, $82.3 million and $77.5 million, respectively. Excluding the effects of hedging activities and interest capitalized during the year ended December 31, 2007, we expect interest payments on our fixed rate Senior Notes for 2007 to be approximately $77.8 million. We expect to make our interest payments with cash flows from operating activities.

Investing Activities

Cash flows used in investing activities totaled $273.7 million for the year ended December 31, 2006, and were comprised of $170.0 million of capital expenditures, $121.0 million of cash contributions for our ownership interest in the Jonah joint venture with Enterprise (primarily for capital expenditures on its Phase V expansion), $20.5 million for the acquisition of Downstream Segment assets, $6.5 million of cash paid for linefill on assets owned, $4.8 million of cash contributions for TE Products’ ownership interest in MB Storage for capital expenditures and $2.5 million of cash contributions for TE Products’ ownership interest in Centennial for operating needs, partially offset by $51.6 million in net cash proceeds from asset sales, of which $38.0 million related to cash proceeds received from the sale of the Pioneer plant on March 31, 2006. Cash flows used in investing activities totaled $350.9 million for the year ended December 31, 2005, and were comprised of $220.6 million of capital expenditures, $69.0 million for the acquisition of Downstream Segment assets, $43.2 million for the acquisition of Upstream Segment assets, $14.4 million of cash paid for linefill on assets owned and $4.2 million of cash contributions for TE Products’ ownership interest in MB Storage for capital expenditures, partially offset by $0.5 million in net cash proceeds from an asset sale in our Midstream Segment. Cash flows used in investing activities totaled $190.2 million for the year ended December 31, 2004, and were comprised of $156.7 million of capital expenditures, $1.5 million of cash contributions for TE Products’ ownership interest in Centennial to cover operating needs and capital expenditures, $21.4 million of cash contributions for TE Products’ ownership interest in MB Storage of which $16.5 million was used to acquire storage assets, $3.4 million for the acquisition of assets and $1.0 million of cash paid for linefill on assets owned, partially offset by $1.2 million in net cash proceeds from the sales of various assets in our Upstream and Downstream Segments. Cash flows used in investing activities for the year ended December 31, 2004, included $7.4 million of cash used in discontinued investing activities related to the construction of the Pioneer plant.

Financing Activities

Cash flows provided by financing activities totaled $0.6 million for the year ended December 31, 2006, and were comprised of $195.1 million of net proceeds received from the public issuance of 5.8 million Units in July 2006, and $84.1 million in borrowings, net of repayments, on our revolving credit facility, partially offset by $278.6 million of distributions paid to unitholders. Cash flows provided by financing activities totaled $80.1 million for the year ended December 31, 2005, and were comprised of $278.8 million of net proceeds received from the public issuance of 7.0 million Units in May and June 2005 and $52.9 million in borrowings, net of repayments, on our revolving credit facility, partially offset by $251.1 million of distributions paid to unitholders and $0.5 million of debt issuance costs related to an amendment of our revolving credit facility. Cash flows used in financing activities totaled $90.1 million for the year ended December 31, 2004, and were comprised of $233.1 million of distributions paid to unitholders, partially offset by $143.0 million in borrowings, net of repayments, from our revolving credit facility.

We paid cash distributions to our limited partners and General Partner, including general partner incentive distributions, of $278.6 million ($2.70 per Unit), $251.1 million ($2.675 per Unit) and $233.1 million ($2.6375 per Unit) during each of the years ended December 31, 2006, 2005 and 2004, respectively. Additionally, on January 12, 2007, we declared a cash distribution of $0.675 per Unit for the quarter ended December 31, 2006. The distribution of $72.4 million was paid on February 7, 2007, to unitholders of record on January 31, 2007 (see Note 14 in the Notes to the Consolidated Financial Statements).

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

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

On December 8, 2006, we held a special meeting of our unitholders. By approval of the various proposals at the special meeting, and upon effectiveness of the New Partnership Agreement, an agreement was effectuated whereby we issued 14,091,275 Units on December 8, 2006 to our General Partner as consideration for the IDR Reduction Amendment. The Units were issued to our General Partner in a transaction not involving a public offering and exempt from registration pursuant to Section 4(2) of the Securities Act of 1933, as amended. The number of Units issued to our General Partner was based upon a predetermined formula that, based on the distribution rate and the number of Units outstanding at the time of the issuance, resulted in our General Partner receiving cash distributions from the newly-issued Units and from its reduced maximum percentage interest in our quarterly distributions approximately equal to the cash distributions our General Partner would have received from its maximum percentage interest in our quarterly distributions without the IDR Reduction Amendment. Effective as of December 8, 2006, the General Partner distributed the newly issued Units to its member, which in turn caused them to be distributed to other affiliates of EPCO.

Other Considerations

Universal Shelf

We have filed with the SEC a universal shelf registration statement that, subject to agreement on terms at the time of use and appropriate supplementation, allows us to issue, in one or more offerings, up to an aggregate of $2.0 billion of equity securities, debt securities or a combination thereof. Taking into account our May 2005 and July 2006 equity offerings, in which we issued $290.8 million and $204.1 million of equity securities, respectively, we have remaining approximately $1.5 billion of availability under this shelf registration, subject to customary marketing terms and conditions.

Credit Facilities

We have in place a $700.0 million unsecured revolving credit facility, including the issuance of letters of credit (“Revolving Credit Facility”), which matures on December 13, 2011. Commitments under the credit facility may be increased up to a maximum of $850.0 million upon our request, subject to lender approval and the satisfaction of certain other conditions. The interest rate is based, at our option, on either the lender’s base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. Financial covenants in the Revolving Credit Facility require that we maintain a ratio of Consolidated Funded Debt to Pro Forma EBITDA (as defined and calculated in the facility) of less than 4.75 to 1.00 (subject to adjustment for specified acquisitions) and a ratio of EBITDA to Interest Expense (as defined and calculated in the facility) of at least 3.00 to 1.00, in each case with respect to specified twelve month periods. Other restrictive covenants in the Revolving Credit Facility limit our ability to, among other things, incur additional indebtedness, make distributions in excess of Available Cash (see Note 14 in the Notes to the Consolidated Financial Statements), incur liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets.

On July 31, 2006, we amended our Revolving Credit Facility. The primary revisions were as follows:

- The maturity date of the credit facility was extended from December 13, 2010 to December 13, 2011. Also under the terms of the amendment, we may request up to two one-year extensions of the maturity date. These extensions, if requested, will become effective subject to lender approval and satisfaction of certain other conditions.

- The amendment releases Jonah as a guarantor of the Revolving Credit Facility and 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 principal aggregate amount of $50.0 million.

- The amendment modifies the financial covenants to, among other things, allow us to include in the calculation of our Consolidated EBITDA (as defined in the Revolving Credit Facility) pro forma adjustments for material capital projects.

- The amendment allows for the issuance of Hybrid Securities (as defined in the Revolving Credit Facility) of up to 15% of our Consolidated Total Capitalization (as defined in the Revolving Credit Facility).

At December 31, 2006, $490.0 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 5.96%. At December 31, 2006, we were in compliance with the covenants of this credit facility.

Treasury Locks

During October 2006, we executed a series of treasury rate lock agreements that extend through June 2007 for a notional amount totaling $200.0 million. These agreements, which are derivative instruments, have been designated as cash flow hedges to offset our exposure to increases in the underlying U.S. Treasury benchmark rate that is expected to be used to establish the fixed interest rate for debt that we expect to incur in 2007. The weighted average rate under the treasury lock agreements was approximately 4.7%. The actual coupon rate of the expected debt issuance will be comprised of the underlying U.S. Treasury benchmark rate, plus a credit spread premium for our debt security. At December 31, 2006, the fair value of these treasury locks was less than $0.1 million. To the extent effective, gains and losses on the value of the treasury locks will be deferred until the forecasted debt is issued and will be amortized to earnings over the life of the debt. No ineffectiveness was required to be recorded as of December 31, 2006.

During February 2007, we executed a series of treasury rate lock agreements that extend through June 2007 for a notional amount totaling $100.0 million. These agreements, which are derivative instruments, hedge our exposure to increases in the underlying U.S. Treasury benchmark rate that is expected to be used to establish the fixed interest rate for debt that we expect to incur in 2007. The weighted average rate under the treasury lock agreements was approximately 4.5%. The actual coupon rate of the expected debt issuance will be comprised of the underlying U.S. Treasury benchmark rate, plus a credit spread premium for our debt security.

Future Capital Needs and Commitments

We estimate that capital expenditures, excluding acquisitions and joint venture contributions, for 2007 will be approximately $300.0 million (including $8.0 million of capitalized interest). We expect to spend approximately $251.0 million for revenue generating projects. We expect to spend approximately $38.0 million to sustain existing operations (including $12.0 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 $3.0 million to improve operational efficiencies and reduce costs among all of our business segments.

Amounts related to Jonah capital expenditures will be reported as joint venture contributions due to the deconsolidation of Jonah on August 1, 2006.

During 2007, TE Products may be required to contribute additional cash to Centennial to cover capital expenditures or other operating needs and to MB Storage to cover capital expenditures prior to the sale of the asset. Additionally, we expect to contribute approximately $120.0 million to our Jonah joint venture for the construction of the Phase V expansion during 2007 and approximately $31.0 million for other capital expenditures. 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

We believe that we will continue to have adequate liquidity to fund future recurring operating and investing activities. Our primary cash requirements consist of normal operating expenses, capital expenditures to sustain existing operations and to complete the Jonah expansion, revenue generating expenditures, interest payments on our Senior Notes and Revolving Credit Facility, distributions to our General Partner and unitholders and acquisitions of new assets or businesses. Our operating cash requirements and capital expenditures to sustain existing operations for 2007 are expected to be funded through our cash flows from operating activities. Long-term cash requirements for expansion projects, acquisitions and debt repayments are expected to be funded by several sources, including cash flows from operating activities, borrowings under credit facilities, joint venture distributions and possibly the issuance of additional equity and debt securities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

Off-Balance Sheet Arrangements

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

Centennial entered into credit facilities totaling $150.0 million, and as of December 31, 2006, $150.0 million was outstanding under those credit facilities, of which $10.0 million matures in April 2007, and $140.0 million matures in April 2024. TE Products and Marathon have each guaranteed one-half of the repayment of Centennial's outstanding debt balance (plus interest) under these credit facilities. The guarantees arose in order for Centennial to obtain adequate financing to fund construction and conversion costs of its pipeline system. Prior to the expiration of the long-term credit facility, TE Products could be relinquished from responsibility under the guarantee should Centennial meet certain financial tests. If Centennial defaults on its outstanding balance, the estimated maximum potential amount of future payments for TE Products and Marathon is $75.0 million each at December 31, 2006. As a result of the guarantee, TE Products recorded an obligation of $0.1 million, which represents the present value of the estimated amount we would have to pay under the guarantee.

TE Products, Marathon and Centennial have entered into a limited cash call agreement, which allows each member to contribute cash in lieu of Centennial procuring separate insurance in the event of a third-party liability arising from a catastrophic event. There is an indefinite term for the agreement and each member is to contribute cash in proportion to its ownership interest, up to a maximum of $50.0 million each. As a result of the catastrophic event guarantee, TE Products has recorded a $4.4 million obligation, which represents the present value of the estimated amount that we would have to pay under the guarantee. If a catastrophic event were to occur and we were required to contribute cash to Centennial, contributions exceeding our deductible might be covered by our insurance, 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 equipment. We have guaranteed the full and timely payment and performance of TCO's obligations under the agreements. Generally, events of default would trigger our performance under the guarantee. The maximum potential amount of future payments under the guarantee is not estimable, but would include base rental payments for both current and future equipment, stipulated loss payments in the event any equipment is stolen, damaged, or destroyed and any future indemnity payments. We carry insurance coverage that may offset any payments required under the guarantees. 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

The following table summarizes our debt repayment obligations and material contractual commitments as of December 31, 2006 (in millions):

	Amount of Commitment Expiration Per Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Revolving Credit Facility, due 2011	$ 490.0	$ —	$ —	$ 490.0	$ —
6.45% Senior Notes due 2008 (1) (2)	180.0	—	180.0	—	—
7.625% Senior Notes due 2012 (2)	500.0	—	—	—	500.0
6.125% Senior Notes due 2013 (2)	200.0	—	—	—	200.0
7.51% Senior Notes due 2028 (1) (2)	210.0	—	—	—	210.0
Interest payments (3)	790.6	106.9	196.5	189.5	297.7
Debt and interest subtotal	2,370.6	106.9	376.5	679.5	1,207.7
Operating leases (4)	69.7	18.7	20.5	13.6	16.9
Purchase obligations (5)	15.0	12.9	1.9	0.1	0.1
Contributions to Jonah (6)	151.0	151.0	—	—	—
Contributions to Centennial	11.1	11.1	—	—	—
Capital expenditure obligations (7)	9.5	9.5	—	—	—
Standby letter of credit (8)	8.7	8.7	—	—	—
Other liabilities and deferred credits (9)	5.2	—	3.5	0.3	1.4
Total	$ 2,640.8	$ 318.8	$ 402.4	$ 693.5	$ 1,226.1

(1) Obligations of TE Products.

(2) Our TE Products subsidiary entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its 7.51% Senior Notes due 2028. At December 31, 2006, the 7.51% Senior Notes include an adjustment to decrease the fair value of the debt by $2.6 million related to this interest rate swap agreement. We also entered into interest rate swap agreements to hedge our exposure to changes in the fair value of our 7.625% Senior Notes due 2012. At December 31, 2006, the 7.625% Senior Notes include a deferred gain, net of amortization, from previous interest rate swap terminations of $28.0 million. At December 31, 2006, our 6.45% Senior Notes, our 7.625% Senior Notes and our 6.125% Senior Notes include $2.1 million of unamortized debt discounts. The fair value adjustments, the deferred gain adjustment and the unamortized debt discounts are excluded from this table.

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

(4) Includes a pipeline capacity lease with Centennial. In January 2003, TE Products entered into a pipeline capacity lease agreement with Centennial for a period of five years that contains a minimum throughput requirement. For the year ended December 31, 2006, TE Products exceeded the minimum throughput requirements on the lease agreement.

(5) We have long and short-term purchase obligations for products and services with third-party suppliers. The prices that we are obligated to pay under these contracts approximate current market prices. The preceding table shows our commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for products and services at December 31, 2006.

(6) Expected contributions to Jonah in 2007 for our share of the Phase V expansion and other capital expenditures.

(7) We have short-term payment obligations relating to capital projects we have initiated. These commitments represent unconditional payment obligations that we have agreed to pay vendors for services rendered or products purchased.

(8) At December 31, 2006, we had outstanding an $8.7 million standby letter of credit in connection with crude oil purchased during the fourth quarter of 2006. The payable related to these purchases of crude oil is expected to be paid during the first quarter of 2007.

(9) Excludes approximately $10.1 million of long-term deferred revenue payments, which are being transferred to income over the term of the respective revenue contracts and $4.2 million related to our estimated long-term portion of our obligation under a catastrophic event guarantee for Centennial. The amount of commitment by year is our best estimate of projected payments of these long-term liabilities.

We expect to repay the long-term, senior unsecured obligations and bank debt through the issuance of additional long-term senior unsecured debt at the time the 2008, 2011, 2012, 2013 and 2028 debts mature, issuance of additional equity, with proceeds from dispositions of assets, cash flow from operations or any combination of the above items.

In addition to the items in the table above, we have entered into various operational commitments and agreements related to pipeline operations and to the marketing, transportation, terminaling and storage of crude oil. The majority of contractual commitments we make for the purchase of crude oil range in term from a thirty-day evergreen to one year. A substantial portion of the contracts for the purchase of crude oil that extend beyond thirty days include cancellation provisions that allow us to cancel the contract with thirty days written notice. During the year ended December 31, 2006, crude oil purchases averaged approximately $746.1 million per month.

Our senior unsecured debt is rated BBB- by Standard and Poors (“S&P”) and Baa3 by Moody’s Investors Service (“Moody’s”). S&P assigned this rating on June 14, 2005, following its review of the ownership structure, corporate governance issues, and proposed funding after the acquisition of the General Partner by DFI. Both ratings are with a stable outlook. A rating reflects only the view of a rating agency and is not a recommendation to buy, sell or hold any indebtedness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that the circumstances warrant such a change and should be evaluated independently of any other rating. The senior unsecured debt of our subsidiary, TE Products, is also rated BBB- by S&P and Baa3 by Moody’s. Both ratings are with a stable outlook and were reaffirmed during the first quarter of 2006.

Recent Accounting Pronouncements

See discussion of new accounting pronouncements in Note 3 in the Notes to the Consolidated Financial Statements.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

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

Commodity Risk

We seek to maintain a position that is substantially balanced between crude oil purchases and sales and future delivery obligations. On the majority of our crude oil derivative contracts, we take the normal purchase and normal sale exclusion in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133*.

On a small portion of our crude oil marketing business, we enter into derivative contracts such as swaps and other business hedging devices for which we cannot take the normal purchase and normal sale exclusion. Generally, hedge accounting is elected. The terms of these contracts are typically one year or less. The purpose is to balance our position or lock in a margin and, as such, the derivative contracts do not expose us to additional significant market risk. For derivatives where hedge accounting is elected, the effective portion of changes in fair value are recorded in other comprehensive income and reclassified into earnings as such transactions are settled. For derivatives where hedge accounting is not elected, we mark these transactions to market and the changes in the fair value are recognized in current earnings. This results in some financial statement variability during quarterly periods; however, any unrealized gains and losses reflected in the financial statements related to marking these transactions to market are offset by realized gains and losses in different quarterly periods when the transactions are settled.

At December 31, 2006, we had a limited number of commodity derivatives that were accounted for as cash flow hedges. Gains and losses on these derivatives are offset against corresponding gains or losses of the hedged item and are deferred through other comprehensive income, thus minimizing exposure to cash flow risk. The fair value of the open positions at December 31, 2006 was $0.7 million. Assuming a hypothetical across-the-board 10% price decrease in the forward curve, the change in fair value of the hedging instrument would have been $0.7 million. The fair value of the open positions was based upon both quoted market prices obtained from NYMEX and were estimated based on quoted prices from various sources such as independent reporting services, industry publications, brokers and marketers. The fair values were determined based upon the differences by month between the fixed contract price and the relevant forward price curve, the volumes for the applicable month and a discount rate of 6%.

Interest Rate Risk

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

At December 31, 2006, we had $490.0 million outstanding under our variable interest rate revolving credit facility. The interest rate is based, at our option, on either the lender’s base rate plus a spread or LIBOR plus a spread in effect at the time of the borrowings and is adjusted monthly, bimonthly, quarterly or semiannually. On January 20, 2006, we entered into interest rate swap agreements with a total notional amount of $200.0 million to hedge our exposure to increases in the benchmark interest rate underlying our variable rate revolving credit facility. These interest rate swaps mature in January 2008. Under the swap agreements, we pay a fixed rate of interest ranging from 4.67% to 4.695% and receive a floating rate based on a three-month U.S. Dollar LIBOR rate. In the third quarter of 2006, these swaps were designated as cash flow hedges. For the period from January 20, 2006 through the date these swaps were designated as cash flow hedges, changes in the fair value of the swaps were recognized in earnings, which resulted in a $2.2 million reduction to interest expense. While these interest rate swaps remain in effect, future changes in the fair value of the cash flow hedges, to the extent the swaps are effective, will be recognized in other comprehensive income until the hedged interest costs are recognized in earnings. At December 31, 2006, the fair value of these interest rate swaps was $1.1 million. Utilizing the balances of our variable interest rate debt outstanding at December 31, 2006, and including the effects of hedging activities, if market interest rates increased 100 basis points, the annual increase in interest expense related to our revolving credit facility would be $2.9 million.

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

	Face Value	Fair Value December 31, 2006	Fair Value December 31, 2005
6.45% TE Products Senior Notes, due January 2008	$180.0	$181.6	$183.7
7.625% Senior Notes, due February 2012	500.0	537.1	552.0
6.125% Senior Notes, due February 2013	200.0	201.6	205.6
7.51% TE Products Senior Notes, due January 2028	210.0	221.5	224.1

In October 2001, TE Products entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its fixed rate 7.51% Senior Notes due 2028. We designated this swap agreement as a fair value hedge. The swap agreement has a notional amount of $210.0 million and matures in January 2028 to match the principal and maturity of the TE Products Senior Notes. Under the swap agreement, TE Products pays a floating rate of interest based on a three-month U.S. Dollar LIBOR rate, plus a spread of 147 basis points, and receives a fixed rate of interest of 7.51%. During the years ended December 31, 2006, 2005 and 2004, we recognized reductions in interest expense of $1.9 million, $5.6 million and $9.6 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. During the years ended December 31, 2006, 2005 and 2004, we reviewed the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized. The fair values of this interest rate swap were liabilities of approximately $2.6 million and $0.9 million at December 31, 2006 and 2005, respectively. Utilizing the balance of the 7.51% TE Products Senior Notes outstanding at December 31, 2006, and including the effects of hedging activities, if market interest rates increased 100 basis points, the annual increase in interest expense would be $2.1 million.

During October 2006, we executed a series of treasury rate lock agreements that extend through June 2007 for a notional amount totaling $200.0 million. These agreements, which are derivative instruments, have been designated as cash flow hedges to offset our exposure to increases in the underlying U.S. Treasury benchmark rate that is expected to be used to establish the fixed interest rate for debt that we expect to incur in 2007. The weighted average rate under the treasury lock agreements was approximately 4.7%. The actual coupon rate of the expected debt issuance will be comprised of the underlying U.S. Treasury benchmark rate, plus a credit spread premium for our debt security. At December 31, 2006, the fair value of these treasury locks was less than $0.1 million. To the extent effective, gains and losses on the value of the treasury locks will be deferred until the forecasted debt is issued and will be amortized to earnings over the life of the debt. No ineffectiveness was required to be recorded as of December 31, 2006.

Item 8. *Financial Statements and Supplementary Data*

Our consolidated financial statements, together with the independent registered public accounting firm's report of Deloitte & Touche LLP ("Deloitte & Touche") and the independent registered public accounting firm's report of KPMG LLP ("KPMG"), begin on page F-1 of this Report.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

On April 6, 2006, the AC Committee, dismissed KPMG as our independent registered public accounting firm and engaged Deloitte & Touche as our new independent registered public accounting firm. As described below, the change in independent registered public accounting firms is not the result of any disagreement with KPMG. We filed a Form 8-K on April 11, 2006 reporting a change of accountants.

During the two fiscal years ended December 31, 2005, and the subsequent interim period through April 6, 2006, there have been no disagreements with KPMG on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of KPMG would have caused them to make reference thereto in their reports on financial statements for such years, and there have been no "reportable events," as described in Item 304(a)(1)(v) of Regulation S-K.

During the two fiscal years ended December 31, 2005, and the subsequent interim period through April 6, 2006, we did not consult Deloitte & Touche regarding (i) either the application of accounting principles to a specified transaction, completed or proposed, or the type of audit opinion that might be rendered on our consolidated financial statements, or (ii) any matter that was either the subject of a "disagreement" or a "reportable event" as set forth in Items 304(a)(1)(iv) and (v) of Regulation S-K, respectively.

We requested that KPMG furnish a letter addressed to the SEC stating whether or not it agreed with the above statements, a copy of which is filed as Exhibit 16 to this Report.

Item 9A. *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 December 31, 2006, the CEO and CFO concluded:

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

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

Changes in Internal Control over Financial Reporting

During 2006, we commenced a project to replace or upgrade our general ledger and consolidation software. The implementation occurred on January 1, 2007. The project is not in response to any identified deficiency or weakness in our internal control over financial reporting. Other than pre-implementation steps taken in connection with the project during the fourth quarter of 2006, there has been no change in our internal control over financial reporting during the fourth quarter of 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

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

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

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2006. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework.

Based on the assessment and those criteria, management believes that the Partnership maintained effective internal control over financial reporting as of December 31, 2006. 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.

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, that TEPPCO Partners, L.P. and subsidiaries (the "Partnership") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Partnership maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006 of the Partnership and our report dated February 28, 2007 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding, the Partnership's adoption of a new accounting standard related to the financial statement presentation of purchases and sales of inventory with the same counterparty.

/s/ Deloitte & Touche LLP

Houston, Texas
February 28, 2007

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Partnership Management

As is commonly the case with publicly traded partnerships, we do not directly employ any of the persons responsible for the management or operations of our business. These functions are performed by the employees of EPCO pursuant to the ASA under the direction of the Board of Directors ("Board") and officers of our General Partner. Our unitholders do not elect the officers or directors of our General Partner. For a description of the ASA, please read "Relationship with EPCO and Affiliates" under Item 13 of this Report.

The limited liability company agreement of our General Partner provides that directors of the General Partner be elected annually by its member and may be removed at any time, with our without cause, by the member. The agreement further provides that executive officers of the General Partner be appointed annually by the Board and that the Board may appoint other officers as it deems necessary for terms set by it. Any officer of the General Partner may be removed with or without cause by the Board. However, Dan L. Duncan, who is Chairman of and controls EPCO, effectively has the ability through his indirect control of the General Partner to appoint, remove and replace any of the officers or directors of our General Partner at any time, with or without cause. Each member of the Board serves until such member's death, resignation or removal. None of the officers of the General Partner serve as officers of EPCO or any of its other affiliates.

The Board and executive management of our General Partner experienced substantial changes in 2006. Mr. Snell was elected a director of the Board on January 6, 2006. On February 14, 2006, Michael A. Creel, Richard H. Bachmann and W. Randall Fowler were elected to the Board of our General Partner. On March 3, 2006, Lee W. Marshall, Sr., Chairman of the Board and Acting Chief Executive Officer ("CEO") of the General Partner, passed away. Effective March 5, 2006, the Board appointed Leonard W. Mallett as Acting CEO. On April 5, 2006, the Board elected Jerry E. Thompson as President, CEO and a director of the General Partner, effective April 11, 2006. On December 28, 2006, Messrs. Creel, Bachmann and Fowler resigned from the Board of our General Partner. There were no disagreements between Messrs. Creel, Bachmann, Fowler and us on any matter relating to our operations, policies or practices which resulted in their resignation.

During 2006, there were seventeen meetings of the Board. In addition, the AC Committee met nineteen times regarding audit and conflicts matters. Messrs. Thompson, Snell, Hutchison and Bracy were present at each Board meeting for their respective periods of service. Messrs. Marshall, Bachmann, Creel and Fowler did not attend one, six, three and three of the seventeen Board meetings for their respective periods of service, respectively, and Messrs. Bachmann, Creel and Fowler each recused themselves from one Board meeting during their respective periods of service. Messrs. Bracy, Hutchison and Snell were present at each AC Committee meeting for their respective periods of service.

In February 2007, the Board combined its AC Committee with its Governance Committee, resulting the Audit, Conflicts and Governance Committee. Unless the context requires otherwise, references to AC Committee include references to the separate Audit and Conflicts Committee and Governance Committee.

Because we are a limited partnership, we are not required to comply with certain requirements of the NYSE. Accordingly, the Board is not required to be comprised of a majority of independent directors under Section 303A.01 of the NYSE Listed Company Manual, and prior to the resignations of Messrs. Creel, Bachmann and Fowler, our Board was not composed of a majority of independent directors. In addition, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of the General Partner maintain a Nominating/Corporate Governance Committee and a Compensation Committee, each consisting entirely of independent directors.

Corporate Governance

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals and maintain the trust and confidence of investors, employees, suppliers, business partners and stakeholders.

Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a "material" relationship with our General Partner or us as described in such listing standards. Based on the foregoing, the Board has affirmatively determined that Michael B. Bracy, Murray H. Hutchison and Richard S. Snell are "independent" directors under the NYSE listing standards. In making its determination, the Board considered the following relationships of Mr. Snell and determined that they do not constitute material relationships that affect his independence:

- From June 2000 until February 14, 2006, Mr. Snell was a director of Enterprise Products GP, the general partner of Enterprise. The Board determined that this relationship is not material because that directorship was terminated soon after he joined our Board and, as described below, the Board determined his ownership of Enterprise common units to be immaterial.

- Until November 2006, Mr. Snell owned 4,557 Enterprise common units, options to purchase 40,000 Enterprise common units; his wife owned 1,100 Enterprise common units; and Mr. Snell and his wife as tenants in common, owned 7,500 common units of Enterprise GP Holdings, which owns the general partner of Enterprise. Mr. Snell is the trustee of family trusts that own a total of 6,000 Enterprise common units and 200 Enterprise GP Holdings common units. The Board determined that these relationships are not material because, consistent with principles in NYSE listing standards, the Board does not view ownership of units, by itself, as a bar to an independence finding. Further, Mr. Snell and his wife no longer own directly any Enterprise or Enterprise GP Holdings common units, and he disclaims beneficial ownership of the units owned by the family trusts.

- Since May 2000, Mr. Snell has been a partner with the law firm of Thompson & Knight LLP in Houston, Texas, which has from time to time provided legal services for Enterprise and its affiliates, including Mr. Duncan. For the three year period ended December 31, 2005, Mr. Duncan paid an aggregate of approximately $51,000 to Thompson & Knight for legal services. The Board determined that this relationship is not material because Thompson & Knight has performed no legal services for us or any of our affiliates, including Mr. Duncan, since Mr. Snell joined the Board and because the fees paid to his firm for prior services were minimal.
- Mr. Snell and Richard Bachmann practiced law as partners for a number of years until 1998. Mr. Bachmann was a member of the Board until December 2006 and serves as a director and executive officer of EPCO, Enterprise and certain affiliates of Enterprise. The Board determined that this relationship is not material because their relationship as partners terminated a number of years before Mr. Snell joined the Board.

Code of Ethics, Corporate Governance Guidelines and Charter of the Audit and Conflicts Committee

We have adopted a Code of Ethics applicable to all employees, including the principal executive officer, principal financial officer, principal accounting officer and directors of the General Partner. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance, the reporting of compliance issues and discipline for violations of the code. A copy of the Code of Ethics is available on our website at www.teppco.com under Corporate Governance. We intend to post on our website any amendments to, or waivers from, our Code of Ethics applicable to our senior officers.

Our Corporate Governance Guidelines address director qualification standards; director responsibilities; director access to management, and as necessary and appropriate, independent advisors; director compensation; director orientation and continuing education; and annual performance evaluation of the Board. The Charter of our AC Committee and our Corporate Governance Guidelines are currently available on our website at www.teppco.com under Corporate Governance. Additionally, the Code of Ethics, our Corporate Governance Guidelines and the Charter of the AC Committee are available in print, without charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request in care of Secretary, TEPPCO Partners, L.P., 1100 Louisiana Street, P.O. Box 2521, Houston, Texas 77252-2521.

Committees of the Board of Directors

Audit, Conflicts and Governance Committee

Our General Partner has an audit, conflicts and governance committee (the "AC Committee") comprised of three board members who are independent under the rules of the SEC regarding audit committees. The members of the AC Committee are Michael B. Bracy (Chairman), Murray H. Hutchison and Richard S. Snell. The current members of the AC Committee are non-employee directors of the General Partner and are not officers or directors of EPCO or its subsidiaries. No member of the AC Committee of our General Partner serves on the audit committees of more than three public companies. Our Board has also determined that Mr. Bracy qualifies as an audit committee financial expert as defined in Item 401(h) of Regulation S-K promulgated by the SEC. Each member of the AC Committee is financially literate within the meaning of the NYSE listing standards.

The AC Committee provides independent oversight with respect to our internal controls, disclosure controls, accounting policies, financial reporting, the integrity of the financial statements, internal audit function, the independent auditors and compliance with legal and regulatory requirements. The AC Committee also reviews the scope and quality, including the independence and objectivity, of the independent and internal auditors. The AC Committee has sole authority as to the retention, evaluation, compensation and oversight of the work of the independent auditors. The independent auditors report directly to the AC Committee. The AC Committee also has sole authority to approve all audit and non-audit services to be provided by the independent auditors and shall ensure that the independent auditors are not engaged to perform specific non-audit services prohibited by law or regulation.

The AC Committee also has a role in resolving certain conflicts of interest transactions. Under our Partnership Agreement, any conflict of interest and any resolution of such conflict of interest shall be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is approved by a majority of the members of the AC Committee and our AC Committee did not act in bad faith. For a discussion of the policies and procedures applicable to the AC Committee's resolution of such transactions, please refer to Item 13. Certain Relationships and Related Transactions, and Director Independence, "–Review and Approval of Transactions with Related Parties." In addition, the AC Committee develops and recommends to the Board a set of governance principles applicable to the General Partner and us and communicates with members of the Board regarding Board meeting format and procedures.

Our AC Committee has established procedures for the receipt, retention and treatment of complaints we receive regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters. Persons wishing to communicate with our AC Committee may do so by calling 1-877-888-0002.

NYSE Corporate Governance Listing Standards

Annual CEO Certification

On March 8, 2006, our CEO certified to the NYSE, as required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual, that as of March 8, 2006, he was not aware of any violation by us of the NYSE's Corporate Governance listing standards.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. Michael B. Bracy, Murray H. Hutchison and Richard S. Snell are independent directors of our General Partner. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "presiding director," who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. Hutchison.

In accordance with NYSE rules, we have established a toll-free, confidential telephone hotline (the "Hotline") so that interested parties may communicate with the presiding director or with all the non-management directors as a group. All calls to this Hotline are reported to the chairman of the committee, who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential Hotline is (877) 888-0002.

Directors and Executive Officers

The following table sets forth certain information with respect to the directors and executive officers of the General Partner as of February 28, 2007.

Name	Age	Position with Our General Partner
Michael B. Bracy	65	Director, Member of Audit and Conflicts Committee*
Murray H. Hutchison	68	Chairman of the Board, Member of the Audit and Conflicts Committee
Richard S. Snell	64	Director, Member of the Audit and Conflicts Committee
Jerry E. Thompson	57	President, Chief Executive Officer and Director
J. Michael Cockrell+	60	Senior Vice President, Commercial Upstream
William G. Manias	45	Vice President and Chief Financial Officer
John N. Goodpasture+	58	Vice President, Corporate Development
Samuel N. Brown+	50	Vice President of Commercial Downstream
Patricia A. Totten	56	Vice President, General Counsel and Secretary

* Chairman of committee

\+ See "— Employment Agreements."

Michael B. Bracy was elected a director of the General Partner in March 2005, upon the change in ownership of the General Partner. He also serves as Chairman of the AC Committee. Prior to being elected to the Board in March 2005, Mr. Bracy served as a director of the general partner of GulfTerra Energy Partners, L.P. ("GulfTerra") from October 1998 until September 30, 2004, when it merged with Enterprise. He was also an audit committee financial expert as determined under the SEC rules while serving on the board of GulfTerra's general partner. Mr. Bracy also serves as an audit committee financial expert on the Board of the General Partner. From 1993 to 1997, Mr. Bracy served as director, executive vice president and chief financial officer of NorAm Energy Corp. For nine years prior, he served in various executive capacities with NorAm Energy Corp. Mr. Bracy is a member of the board of directors of Itron, Inc.

Murray H. Hutchison was elected a director of the General Partner in March 2005, upon the change in ownership of the General Partner. He also serves as a member of the AC Committee. Mr. Hutchison is a private investor managing his own portfolio. He also consults with corporate managements on strategic issues. Mr. Hutchison retired in 1997 as chairman and chief executive officer of the IT Group (International Technology Corporation) after serving in that position for over 27 years. Mr. Hutchison serves as chairman of the board of Huntington Hotel Corporation, as lead director of Jack in the Box Inc., and as a director on the boards of Cadiz Inc., The Olson Company, Cardium Therapeutics, Inc. and The Hobbs Sea World Research Institute.

Richard S. Snell was elected a director of the General Partner in January 2006. He also serves as a member of the AC Committee. Mr. Snell was an attorney with the Snell & Smith, P.C. law firm in Houston, Texas, from the founding of the firm in 1993 until May 2000. Since May 2000, he has been a partner with the firm of Thompson & Knight LLP in Houston, Texas, and is a certified public accountant. Mr. Snell served as a director of Enterprise Products GP from June 2000 until his resignation in February 2006.

Jerry E. Thompson is President, Chief Executive Officer and a director of the General Partner, having been elected in April 2006. Mr. Thompson was previously chief operating officer of CITGO Petroleum Corporation ("CITGO") from 2003 to March 2006, when he retired. Mr. Thompson joined CITGO in 1971 and advanced from a process engineer to positions of increasing responsibilities in the operations, supply and logistics, business development, planning and financial aspects of CITGO. He was elected vice president of CITGO's refining business in 1987 and as its senior vice president in 1998. Mr. Thompson serves as the principal executive officer of the General Partner. Mr. Thompson serves as a director on the board of directors of Susser Holdings Corporation.

J. Michael Cockrell is Senior Vice President, Commercial Upstream of the General Partner, having been elected in February 2003. Mr. Cockrell was previously Vice President, Commercial Upstream from September 2000 until February 2003. He was elected Vice President of the General Partner in January 1999 and also serves as President of TEPPCO Crude GP, LLC. He joined PanEnergy in 1987 and served in a variety of positions in supply and development, including president of Duke Energy Transport and Trading Company, LLC ("DETTCO").

William G. Manias is Vice President and Chief Financial Officer of the General Partner, having been elected effective January 13, 2006. Mr. Manias was vice president of corporate development of Enterprise Products GP from October 2004 until January 2006. He served as vice president and chief financial officer of Gulfterra Energy Partners, L.P. from February 2004 until October 2004. Mr. Manias was previously vice president of business development and strategic planning at El Paso Energy Partners, L.P. from October 2001 to February 2004. Prior to his joining El Paso Energy Partners, L.P. in October 2001, Mr. Manias served as vice president of investment banking for J.P. Morgan Securities Inc. (formerly Chase Securities Inc.) from January 1996 to August 2001. Mr. Manias serves as principal financial and accounting officer of the General Partner.

John N. Goodpasture is Vice President, Corporate Development of the General Partner, having joined the General Partner in November 2001. Mr. Goodpasture was previously vice president of business development for Enron Transportation Services from June 1999 until he joined the General Partner. Prior to his employment at Enron Transportation Services, Mr. Goodpasture spent 19 years in various executive positions at Seagull Energy Corporation (now Devon Energy Corporation), a large independent oil and gas company. At Seagull Energy, Mr. Goodpasture had most recently served for over ten years as senior vice president, pipelines and marketing. Mr. Goodpasture serves as a director on the board of directors of Blue Dolphin Energy Company.

Samuel N. Brown is Vice President, Commercial Downstream of the General Partner, having been elected in June 2005. He was previously Vice President, Pipeline Marketing and Business Development in our Upstream Segment from September 2000 to June 2005. Mr. Brown joined the General Partner in 1998 as Vice President of Pipeline Marketing and Business Development. Prior to joining the General Partner in 1998, he was vice president of commercial operations at DETTCO from 1996 until 1998.

Patricia A. Totten is Vice President, General Counsel and Secretary of the General Partner, having been elected in March 2006. She was previously associate general counsel and deputy general counsel for Enterprise Products GP from December 2002 to January 2006. Prior to joining Enterprise Products GP in August 2002, Ms. Totten served as general counsel of Solid Systems Inc. from March 2001 to August 2002, and as assistant general counsel and vice president of marketing for a small wireless company from 1995 to December 2000 that was merged into Verizon Wireless in 2000.

In addition to our Executive Officers, Mark G. Stockard has served as Treasurer since May 2002. Mr. Stockard was Assistant Treasurer of the General Partner from July 2001 until May 2002. He was previously Controller from October 1996 until May 2002. Mr. Stockard joined the General Partner in October 1990. Tracy E. Ohmart has served as Controller since May 2002. Mr. Ohmart served as acting Chief Financial Officer of the General Partner from July 2005 until January 2006. Mr. Ohmart joined the General Partner in January 2001 and held various positions with the General Partner until he became Assistant Controller in May 2001. Prior to his employment with the General Partner, Mr. Ohmart spent 12 years in various positions at ARCO Pipe Line Company, most recently serving as supervisor of general accounting and policy.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires directors, officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of such equity securities. Based on information furnished to the General Partner and written representation that no other reports were required, to the General Partner’s knowledge, all applicable Section 16(a) filing requirements were complied with during the year ended December 31, 2006, except for a Form 3 report upon election as an officer that was filed late by Mr. Brown, a report covering two transactions that was filed late by Mr. Thompson and two reports covering two transactions that was filed late by Mr. Mallett during his respective period of service.

Item 11. ***Executive Compensation***

Compensation Discussion and Analysis

Overview of Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our business. We are managed by our General Partner, the executive officers of which are employees of EPCO. Under the ASA with EPCO, we reimburse EPCO for the compensation of our executive officers. The reimbursement is generally based on time allocated during a period between our business activities and those of EPCO or the EPCO affiliates who reimburse EPCO pursuant to the ASA.

Throughout this Report, each person who served as CEO during 2006, each person who served as CFO during 2006, the three other most highly compensated executive officers serving at December 31, 2006, and two former executive officers for whom disclosure would have been required but for the fact that each was not serving at December 31, 2006 are referred to as the "Named Executive Officers" and are included in the Summary Compensation Table below. Compensation paid or awarded by us in 2006 with respect to such Named Executive Officers reflects only that portion of compensation paid by EPCO allocated to us pursuant to the ASA, including an allocation of a portion of the cost of EPCO's equity-based long-term incentive plans and our long-term incentive plans. During 2006, the only Named Executive Officer who did not spend substantially all of his time on our business was Mr. Mallett, whose service as an executive officer of our General Partner ended in July 2006 when he became an officer of EPCO. Dan L. Duncan controls EPCO and has ultimate decision-making authority with respect to compensation of our Named Executive Officers. The elements of compensation, and EPCO's decisions regarding the determination of payments, are not subject to approvals by our Board or AC Committee, except for awards under our and EPCO's long-term incentive plans. Awards under EPCO's and our long-term incentive plans are approved by the AC Committee of our General Partner. We do not have a separate compensation committee (see Item 10. Directors, Executive Officers and Corporate Governance, "– Partnership Management").

Compensation Objectives

The elements of EPCO's compensation program, discussed below, along with EPCO's other rewards (e.g., benefits, work environment, career development), are intended to provide a total rewards package to employees that provides competitive compensation opportunities to align and drive employee performance toward the creation of sustained long-term unitholder value, which will also allow the attraction, motivation and retention of high quality talent with the skills and competencies we require.

Components of Executive Officer Compensation and Compensation Decisions

The primary elements of EPCO's compensation program are a combination of annual cash and long-term equity-based compensation. During 2006, elements of compensation for our Named Executive Officers consisted of the following:

- Annual base salary;
- Discretionary annual cash awards;
- Awards under our and EPCO's long-term incentive plans; and
- Other compensation, including very limited perquisites.

In order to assist Mr. Duncan and EPCO with compensation decisions, Jerry E. Thompson, our CEO, and the Senior Vice President of Human Resources for EPCO formulate preliminary compensation recommendations for all of the Named Executive Officers other than Mr. Thompson. Mr. Duncan, after consulting with the Senior Vice President of Human Resources for EPCO, independently makes compensation decisions with respect to Mr. Thompson. In making these compensation decisions for the Named Executive Officers, including Mr. Thompson, EPCO takes note of market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, various relevant compensation surveys. EPCO considered market data in a 2004-2005 survey prepared for it by an outside compensation consultant, but did not otherwise consult with compensation consultants in determining 2006 compensation for our Named Executive

Officers. During late 2006, EPCO engaged an outside compensation consultant to prepare a report that it expects to consider when determining future compensation, but EPCO did not use this report in making decisions on discretionary annual cash compensation with respect to 2006 performance for any of our Named Executive Officers. Mr. Duncan and EPCO do not use any formula or specific performance-based criteria for our Named Executive Officers in connection with services performed for us; rather, Mr. Duncan and EPCO determine an appropriate level and mix of compensation on a case-by-case basis. Further, there is no established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation. All compensation determinations are discretionary and, as noted above, subject to Mr. Duncan's ultimate decision-making authority, except for equity awards under our and EPCO's long-term incentive plans.

Discretionary cash awards, in combination with annual base salaries, are intended to yield competitive total cash compensation levels for the executive officers and drive performance in support of the business strategies of EPCO and its affiliates at both the partnership and individual levels. It is EPCO's general policy to pay these awards during the first quarter of each year.

The 2006 awards granted to the Named Executive Officers under the long-term incentive plans were approved by our AC Committee based on recommendations that were the result of consultation among Mr. Duncan and the Senior Vice President of Human Resources for EPCO. The long-term incentive component of our compensation package is intended to provide a means for key employees providing services to us to develop a sense of proprietorship and personal involvement in the development and financial success of our partnership through equity-based awards. The intended result of these awards is to align the long-term interests of our executive officers with those of our unitholders.

For 2006, all equity-based awards were made in the form of phantom units that provide for a cash payment on vesting. Prior to the recent adoption of the EPCO, Inc. 2006 TPP Long-Term Incentive Plan ("2006 LTIP"), our General Partner's practice was to award phantom units to executive officers under the Texas Eastern Products Pipeline Company Retention Incentive Compensation Plan ("1999 Plan") or the Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan ("2000 LTIP"). Vesting of phantom units issued under the 2000 LTIP is based upon the performance of the Partnership during a performance period, and the participant can receive up to 150% of the value of the phantom units at the end of the performance period. However, it is also possible that no amounts will be payable for phantom unit awards under the 2000 LTIP if certain performance conditions are not met. Vesting of phantom units issued under the 1999 Plan is based solely on the Unit price, the number of phantom units and the passage of specified vesting periods. When Mr. Thompson and Mr. Manias joined our General Partner, they were issued grants of phantom units under the 1999 Plan, primarily because the flexibility of the vesting provisions and method of determination of compensation under this plan were deemed more appropriate compensation and better aligned with EPCO's compensation practices.

The Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan ("2005 Phantom Unit Plan") is generally used to make awards of phantom units to non-executive employees, and payout under this plan is also based upon the performance of the Partnership during a performance period, permitting participants to receive up to 150% of the value of the phantom units at the end of the performance period. It is also possible that no amounts will be payable for phantom unit awards under the 2005 Phantom Unit Plan if certain performance conditions are not met. Mr. Ohmart was granted phantom units under the 2005 Phantom Unit Plan since, other than his service as Acting CFO, he is not considered an executive officer. Mr. Ohmart is deemed a Named Executive Officer herein due to his period of service as Acting CFO in January 2006.

In addition to the payments under the 1999 Plan, the 2000 LTIP and the 2005 Phantom Unit Plan described above, prior to vesting, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under such award. See " – Summary of Long-Term Incentive Plans of TEPPCO" below for further information on our incentive plans.

EPCO generally does not pay for perquisites for any of our Named Executive Officers, other than reimbursement of certain club membership dues and parking, and expects to continue its policy of covering very limited perquisites allocable to our Named Executive Officers. EPCO also makes matching contributions under its 401(k) plan for the benefit of our Named Executive Officers in the same manner as for other EPCO employees. Mr.

Duncan and the Senior Vice President of Human Resources for EPCO periodically review the levels of perquisites and other personal benefits provided to Named Executive Officers.

We believe that each of the base salary, cash awards and equity awards fit our overall compensation objectives and those of EPCO, as stated above, by ensuring that we retain the services of key employees providing services to us and providing incentives for such employees to exert maximum efforts for our success, thereby advancing the interests of all unitholders and the General Partner.

In December 2006, our unitholders approved the 2006 LTIP. We expect that grants of awards will be made under this plan in 2007 (see Note 4 in the Notes to the Consolidated Financial Statements). This plan will allow for various forms of equity or equity-based awards not contained in previous plans, and will further our objective of having flexible means by which to incentivize employees and non-employee directors.

Employment Arrangements and Termination or Change-in-Control Payments

Prior to the change in ownership of our General Partner on February 24, 2005, our compensation philosophy and objectives were aligned with those of DEFS, as the owner of our General Partner. Upon or near appointment, each named executive officer and the General Partner entered into an employment agreement, which provided for annual base salaries and increases, annual bonus payments and various change in control and termination provisions. As a result of the change in ownership of our General Partner in 2005, we are aligning our compensation philosophy and objectives with those of EPCO. EPCO's practice is not to enter into employment agreements with its named executive officers. Accordingly, executive officers hired since EPCO acquired our General Partner, such as Messrs. Thompson and Manias, have not entered into employment agreements with EPCO. Further, EPCO and each of our four Named Executive Officers with existing employment agreements entered into supplements to their employment agreements in 2007 which terminate the agreements upon the satisfaction of certain conditions.

The four Named Executive Officers with pre-existing employment agreements are entitled to a retention payment and insurance benefits if such Named Executive Officer is terminated without cause or because of a disability or death, or resigns as a result of relocation, prior to June 1, 2008. These four Named Executive Officers also have outstanding awards made prior to February 2005 under the 2000 LTIP that provide for certain payments in the event of a change in control. Additionally, recipients of awards under the 1999 Plan, the 2000 LTIP and the 2005 Phantom Unit Plan are entitled to payments in the event of death, disability, and in some cases, retirement. See "Employment Arrangements and Potential Payments upon Termination or Change in Control" below.

Chief Executive Officer Compensation

In connection with his appointment as President and CEO of our General Partner, Mr. Thompson received an annual base salary of $450,000, and a $500,000 signing bonus, which was paid in January 2007. Mr. Thompson's annual bonus for 2007 will be at least 60% of his base salary for those years and will otherwise be discretionary. In addition, Mr. Thompson was issued 39,000 phantom units under the 1999 Plan. One-third of these phantom units will vest on April 11, 2007, one-third on April 11, 2008 and the remaining one-third on April 11, 2009, assuming Mr. Thompson's continuing employment through the vesting period, or earlier in the event of death or disability. The phantom units are entitled to cash distributions made on our Units and, upon vesting, entitle Mr. Thompson to a cash payment equal to the closing price of our Unit on the preceding day. Mr. Thompson is also eligible to participate in the other long-term incentive compensation programs offered by us and our General Partner.

Tax and Accounting Implications

Nonqualified Deferred Compensation

On October 22, 2004 the American Jobs Creation Act of 2004 was signed into law, enacting a new Section 409A of the U.S. Internal Revenue Code and changing the tax rules relating to nonqualified deferred compensation. A number of the awards under our long-term incentive plans may be considered deferred compensation for purposes of this new Section 409A of the Internal Revenue Code. The consequence of a violation of Section 409A is immediate taxation and an additional excise tax on the recipient of the compensation. While final regulations have not yet been issued, we believe our incentive awards have been structured in a manner that is compliant with or exempt from the application of Section 409A of the Internal Revenue Code.

Significant Accounting Considerations

We account for our compensation plans under Financial Accounting Standards Board SFAS No. 123(R) (revised 2004), *Share-Based Payment*, which was issued in December 2004. SFAS 123(R) is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*, as amended by SFAS No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure* and supersedes Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*. SFAS 123(R) requires that the cost resulting from all share-based payment transactions be recognized in the financial statements at fair value. We have determined that our 1999 Plan and our 2005 Phantom Unit Plan are liability awards under the provisions of SFAS 123(R). No additional compensation expense has been recorded in connection with the adoption of SFAS 123(R) as we have historically recorded the associated liabilities at fair value. The adoption of SFAS 123(R) did not have a material effect on our financial position, results of operations or cash flows.

Compensation Committee Report

We do not have a separate compensation committee. The Board of Directors of our General Partner has reviewed and discussed the Compensation Discussion and Analysis with management. Based on our review of and discussion with management with respect to the Compensation Discussion and Analysis, we determined that the Compensation Discussion and Analysis be included in this Report.

Submitted by: Jerry E. Thompson
Michael B. Bracy
Richard S. Snell
Murray H. Hutchison

Nothwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Exchange Act, as amended, that incorporate future filings, including this Report, in whole or in part, the foregoing report shall not be incorporated by reference into any such filings.

Summary Compensation Table

The following table reflects information regarding compensation paid or accrued by our General Partner for the year ended December 31, 2006, with respect to each of our Named Executive Officers.

Name and Principal Position	Salary ($)	Bonus ($) (8)	Stock Awards ($) (9)	All Other Compensation ($) (10)	Total ($)
Jerry E. Thompson (1) *President and Chief Executive Officer*	325,673	770,000	721,000	58,007	1,874,680
William G. Manias (2) *Vice President and Chief Financial Officer*	192,825	75,000	37,059	49,497	354,381
Lee W. Marshall, Sr. (3) *Chairman and Acting Chief Executive Officer*	87,500	—	—	2,104	89,604
Leonard W. Mallett (4) *Acting Chief Executive Officer and Senior Vice President, Operations*	197,739	66,000	92,204	140,837	496,780
Tracy E. Ohmart (5) *Acting Chief Financial Officer and Controller*	163,851	42,000	35,384	62,343	303,578
J. Michael Cockrell *Senior Vice President, Commercial Upstream*	255,628	98,000	119,706	157,611	630,945
Samuel N. Brown *Vice President, Commercial Downstream*	220,901	75,000	88,754	129,822	514,477
John N. Goodpasture *Vice President, Corporate Development*	231,737	62,000	106,792	107,397	507,926
James C. Ruth (6) *Senior Vice President and General Counsel*	40,572	56,036	—	1,329,977	1,426,585
C. Bruce Shaffer (7) *Vice President, Human Resources and Ethics and Compliance Officer*	130,044	—	—	949,117	1,079,161

(1) Effective April 5, 2006, Mr. Thompson was appointed President and CEO of our General Partner.

(2) Effective January 12, 2006, Mr. Manias was appointed Vice President and CFO of our General Partner.

(3) Mr. Marshall served as Acting CEO effective December 31, 2005 until his passing on March 3, 2006. Mr. Marshall was not compensated for his position as Acting CEO. Compensation reflected in the table is for his service as a director and as Chairman of the Board.

(4) Mr. Mallett was Senior Vice President of Operations through July 25, 2006, when he became Senior Vice President, Environmental, Health, Safety & Training of EPCO. Additionally, Mr. Mallett served as Acting CEO for the period March 5, 2006, through April 5, 2006, when Mr. Thompson was appointed President and CEO. Mr. Mallett did not receive additional compensation for his service as Acting CEO. Amounts presented reflect compensation amounts allocated to us based on the percentage of time spent on our business for the full year 2006.

(5) Mr. Ohmart served as Acting CFO from July 12, 2005 through January 12, 2006, when Mr. Manias was appointed Vice President and CFO of our General Partner.

(6) Mr. Ruth retired effective February 28, 2006. He received a lump sum payment upon his termination. See "– Executive Employment Contracts and Termination of Employment Arrangements" for further information.

(7) Mr. Shaffer retired effective August 31, 2006. He received a lump sum payment upon his termination. See "– Executive Employment Contracts and Termination of Employment Arrangements" for further information.

(8) Amounts represent discretionary annual cash awards accrued during the 2006 year. Payments under the discretionary annual cash awards program are made in the subsequent year.

(9) Amounts represent accrued balances under the equity incentive plan awards granted to the Named Executive Officers. These calculations are based on the assumptions that (i) the closing price of a Unit at December 29, 2006 was $40.31; (ii) the performance percentage applied to (a) the 1999 Plan is 100%, (b) the 2000 LTIP is 150%, (c) the 2005 Phantom Unit Plan is 106.02%, and (iii) the percentage of the number of days of the performance period to date compared to the total performance period. See discussion of the equity awards and the 2006 grants from these equity incentive plans to the Named Executive Officers below.

(10) Primary components include (i) EPCO matching contributions under funded, qualified, defined contribution retirement plans; (ii) quarterly distribution equivalents paid on equity incentive plan awards; (iii) payouts from the TEPPCO Retirement Cash Balance Plan resulting from plan termination; (iv) for Mr. Ruth and Mr. Shaffer, severance payments, including unused vacation days and COBRA insurance premiums and (v) the imputed value of premiums paid by EPCO for Named Executive Officers' life insurance. Components of "All Other Compensation" for which $10,000 or more was paid to any Named Executive Officer as set forth below for each Named Executive Officer are as follows:

Name	Matching Contributions Under Funded Qualified Defined Contribution Retirement Plan ($)	Quarterly Distribution Equivalents Paid on Equity Incentive Plan Awards ($)	Payouts from TEPPCO Retirement Cash Balance Plan ($)	Severance Payments ($)	Other Compensation ($)	Total All Other Compensation ($)
Jerry E. Thompson	3,750	52,650	—	—	1,607	58,007
William G. Manias	15,400	30,725	—	—	3,372	49,497
Leonard W. Mallett	13,552	10,039	116,143	—	1,103	140,837
Tracy E. Ohmart	13,867	5,468	42,550	—	458	62,343
J. Michael Cockrell	15,400	13,028	120,888	—	8,295	157,611
Samuel N. Brown	15,400	9,518	97,680	—	7,224	129,822
John N. Goodpasture	15,400	11,610	74,512	—	5,875	107,397
James C. Ruth	5,157	1,620	116,044	1,206,773	383	1,329,977
C. Bruce Shaffer	12,059	11,340	13,549	911,661	508	949,117

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Grants of Plan-Based Awards in Fiscal Year 2006

The following table presents information concerning each grant of an award made to a Named Executive Officer in 2006 under any plan. The amount of equity incentive plan awards reflected below are phantom units awarded under the 1999 Plan, 2000 LTIP and 2005 Phantom Unit Plan, as set forth below.

			Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards (5)		
Name	Grant Date (6)	Authorization Date (7)	Threshold ($)	Target ($)	Maximum ($)	Threshold (#) (8)	Target (#) (9)	Maximum (#) (10)
Jerry E. Thompson (1)	4/11/2006	4/11/2006	—	—	—	—	39,000	—
William G. Manias (1)	1/1/2006	4/1/2006	—	—	—	—	2,800	—
Leonard W. Mallett (2)	1/1/2006	4/4/2006	—	—	—	—	2,700	4,050
Tracy E. Ohmart (3)	1/1/2006	4/4/2006	—	—	—	—	2,700	4,050
	5/1/2006	N/A	—	58,240	—	—	—	—
J. Michael Cockrell (2)	1/1/2006	4/4/2006	—	—	—	—	3,100	4,650
John N. Goodpasture (2)	1/1/2006	4/4/2006	—	—	—	—	2,800	4,250
Samuel N. Brown (2)	1/1/2006	4/4/2006	—	—	—	—	2,700	4,050
C. Bruce Shaffer (2) (4)	1/1/2006	4/4/2006	—	—	—	—	—	—

(1) Amount represents an award of phantom units under the 1999 Plan.

(2) Amount represents an award of phantom units under the 2000 LTIP.

(3) Amount on January 1, 2006 represents an award under our 2005 Phantom Unit Plan and the amount on May 1, 2006 represents a non-equity incentive cash payment awarded under a retention agreement.

(4) Mr. Shaffer was granted an award in 2006 of 2,400 phantom units under the 2000 LTIP; however, that award was forfeited with termination of participation on August 31, 2006.

(5) Phantom units will be settled in cash based upon the market price of the Units at the end of the performance period (see "– Summary of Long-Term Incentive Plans of TEPPCO" below).

(6) Grant Date is the first date of the performance period for awards under the 2000 LTIP and the 2005 Phantom Unit Plan. For awards under the 1999 Plan and Mr. Ohmart's retention agreement, Grant Date is the date the grant was awarded.

(7) Authorization Date is the date the grant was formally awarded to the Named Executive Officer.

(8) No amounts will be payable for awards granted in 2006 unless Economic Value Added for the three year performance period exceeds $85.8 million. For more information about vesting of phantom units, see "– Summary of Long-Term Incentive Plans of TEPPCO" and the Outstanding Equity Awards at 2006 Fiscal Year-End table below.

(9) Target represents number of phantom units. These amounts assume that the 13% increase in Economic Value Added for 2006 as compared with 2005 is maintained for each of the three years in the performance period. There can be no assurance that any specific amount of Economic Value Added will be attained for such period.

(10) The maximum potential payout under the 2000 LTIP and the 2005 Phantom Unit Plan is 150% of phantom units awarded.

Summary of Long-Term Incentive Plans of TEPPCO

The following are long-term incentive plans under which we grant awards to participants, including certain Named Executive Officers, in order to align the long-term interest of participants with those of our unitholders. For a discussion regarding change of control and termination payments for each of the plans, please see "–Employment Arrangements and Potential Payments upon Termination or Change in Control."

1999 Plan

Effective January 1, 1999, the General Partner adopted the 1999 Plan. The 1999 Plan provides key employees with incentive awards whereby a participant is granted phantom units. These phantom units are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at stated redemption dates. The fair market value of each phantom unit is equal to the closing price of a Unit as reported on the NYSE on the redemption date.

Under the agreement for the phantom units, each participant vests in the number of phantom units initially granted under his or her award according to the terms agreed upon at the grant date. Death or disability of the participant will accelerate vesting. Each participant is required to redeem their phantom units as they vest. Each participant is also entitled to quarterly cash distributions equal to the product of the number of phantom units outstanding for the participant and the amount of the cash distribution that we paid per Unit to our unitholders.

2000 LTIP

Effective January 1, 2000, the General Partner established the 2000 LTIP to provide key employees incentives to achieve improvements in our financial performance. Generally, upon the close of a three-year performance period, if the participant is then still an employee of EPCO, the participant will receive a cash payment in an amount equal to (1) the applicable performance percentage specified in the award multiplied by (2) the number of phantom units granted under the award multiplied by (3) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. Generally, a participant's performance percentage is based upon the improvement of our Economic Value Added (as defined below) during a three-year performance period over the Economic Value Added during the three-year period immediately preceding the performance period. If a participant incurs a separation from service during the performance period due to death, disability or retirement (as such terms are defined in the 2000 LTIP), the participant will be entitled to receive a cash payment in an amount equal to the amount computed as described above multiplied by a fraction, the numerator of which is the number of days that have elapsed during the performance period prior to the participant's separation from service and the denominator of which is the number of days in the performance period.

The performance period applicable to awards granted in 2006 is the three-year period that commenced on January 1, 2006, and ends on December 31, 2008. Each participant's performance percentage is the result of 100% +/- [(A) minus (C)] divided by [(C) minus (B)] where (A) is the actual Economic Value Added for the performance period, (B) is $85.8 million (which represents the actual Economic Value Added for the three-year period immediately preceding the performance period) and (C) is $118.6 million (which represents the Target Economic Value Added during the three-year performance period). No amounts will be payable under the awards granted in 2005 for the 2000 LTIP unless Economic Value Added for the three year performance period exceeds $85.8 million. The performance percentage may not exceed 150%.

The performance period applicable to awards granted in 2005 is the three-year period that commenced on January 1, 2005, and ends on December 31, 2007. Each participant's performance percentage is the result of 100% +/- [(A) minus (C)] divided by [(C) minus (B)] where (A) is the actual Economic Value Added for the performance period, (B) is $73.0 million (which represents the actual Economic Value Added for the three-year period immediately preceding the performance period) and (C) is $97.7 million (which represents the Target Economic Value Added during the three-year performance period). No amounts will be payable under the awards granted in 2006 for the 2000 LTIP unless Economic Value Added for the three year performance period exceeds $73.0 million. The performance percentage may not exceed 150%. There are no outstanding awards granted prior to 2005.

Economic Value Added means our average annual EBITDA for the performance period minus the product of our average asset base and our cost of capital for the performance period. EBITDA means our earnings before net interest expense, other income – net, depreciation and amortization and our proportional interest in EBITDA of our joint ventures as presented in our consolidated financial statements prepared in accordance with generally accepted accounting principles, except that at his discretion the CEO of the General Partner may exclude gains or losses from extraordinary, unusual or non-recurring items. Average asset base means the quarterly average, during the performance period, of our gross value of property, plant and equipment, plus products and crude oil operating oil supply and the gross value of intangibles and equity investments. Our cost of capital is approved by our CEO at the date of award grant.

In addition to the payment described above, during the performance period, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under this award.

2005 Phantom Unit Plan

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

In addition to the payment described above, during the performance period, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under this award. If a participant incurs a separation from service during the performance period due to the death or disability (as such term is defined in the 2005 Phantom Unit Plan), the participant will be entitled to receive a cash payment in an amount equal to the amount computed as described above multiplied by a fraction, the numerator of which is the number of days that have elapsed during the performance period prior to the participant's separation from service and the denominator of which is the days in the performance period.

2006 LTIP

At a special meeting of our unitholders on December 8, 2006, our unitholders approved the 2006 LTIP, which provides for awards of our Units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under this plan may be granted in the form of restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights.

Outstanding Equity Awards at 2006 Fiscal Year-End

The following table presents information concerning phantom unit plan awards that have not vested for each Named Executive Officer at December 31, 2006.

	Unit Awards				
Name	Number of Shares or Units That Have Not Vested (#)	Market Value of Shares or Units That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (1)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (2)	Vesting Dates of Awards
Jerry E. Thompson	—	—	39,000	1,572,090	Various (3)
William G. Manias	—	—	2,800	112,868	1/1/2010
Leonard W. Mallett	—	—	4,900	197,519	(4)
Tracy E. Ohmart	—	—	2,700	108,837	12/31/2008
J. Michael Cockrell	—	—	5,600	225,736	(5)
John N. Goodpasture	—	—	5,000	201,550	(6)
Samuel N. Brown	—	—	4,200	169,302	(7)

(1) Amount represents the number of phantom units awarded under the equity incentive plans that have not vested because satisfaction of a performance condition is still pending.

(2) Amount reflects the market value of the target at December 31, 2006, using the December 29, 2006 Unit price of $40.31 per Unit.

(3) One-third of these phantom units will vest on April 11, 2007, one-third on April 11, 2008 and the remaining one-third on April 11, 2009.

(4) 2,200 phantom units vest on December 31, 2007 and 2,700 phantom units vest on December 31, 2008.

(5) 2,500 phantom units vest on December 31, 2007 and 3,100 phantom units vest on December 31, 2008.

(6) 2,200 phantom units vest on December 31, 2007 and 2,800 phantom units vest on December 31, 2008.

(7) 1,500 phantom units vest on December 31, 2007 and 2,700 phantom units vest on December 31, 2008.

Option Exercises and Stock Vested Table

The following table presents information concerning vesting of phantom unit awards during 2006 for each of the Named Executive Officers on an aggregate basis.

Name	Unit Awards: Number of Units Acquired On Vesting (#)	Unit Awards: Value Realized On Vesting ($) (1)
James C. Ruth	—	115,073
C. Bruce Shaffer	—	148,600

(1) Amount represents the payout from the 2000 LTIP effective with the Named Executive Officer's respective retirement.

Pension Benefits Table

The following table presents information concerning each plan that provides for payments or other benefits at, following, or in connection with the retirement, of each Named Executive Officer.

Name	Plan Name	Number of Years of Credited Service	Present Value of Accumulated Benefit	Payments During Last Fiscal Year (1)
Leonard W. Mallett	TEPPCO Retirement Cash Balance Plan	—	—	$116,143
Tracy E. Ohmart	TEPPCO Retirement Cash Balance Plan	—	—	42,550
J. Michael Cockrell	TEPPCO Retirement Cash Balance Plan	—	—	120,888
John N. Goodpasture	TEPPCO Retirement Cash Balance Plan	—	—	74,512
Samuel N. Brown	TEPPCO Retirement Cash Balance Plan	—	—	97,680
James C. Ruth	TEPPCO Retirement Cash Balance Plan	—	—	116,044
C. Bruce Shaffer	TEPPCO Retirement Cash Balance Plan	—	—	13,549

(1) Amount represents the 2006 payout from the TEPPCO Retirement Cash Balance Plan as a result of the termination of the plan on December 31, 2005 (see Note 5 in the Notes to the Consolidated Financial Statements).

Nonqualified Deferred Compensation for the 2006 Fiscal Year

During 2006, no Named Executive Officer received deferred compensation (other than incentive awards described elsewhere) on a basis that was not tax-qualified with respect to any defined contribution or other plan.

Employment Arrangements and Potential Payments upon Termination or Change in Control

2000 LTIP

The acquisition of our General Partner by an affiliate of EPCO in February 2005 resulted in a change in control for purposes of awards made prior to such date under the 2000 LTIP. If the employment of a participant, including a Named Executive Officer, is terminated without cause in connection with a change in control, then, in lieu of the payout described above, the participant will receive a payment following separation from service equal to the product of (i) the average closing price of our Units for the 10 days preceding the change in control and (ii) the number of our Units subject to the participant's award. A termination of employment will be deemed to be in connection with the change in control if, during the performance period in which the change in control occurs, the participant is terminated without cause (after the change in control by us or before or on the change in control by the person who is a party to the transaction which constitutes the change in control) or the employee terminates for good reason. For this purpose, good reason means (i) the assignment to the participant of duties materially inconsistent with the participant's duties, authorities and responsibilities immediately prior to the change in control, (ii) the diminution of the participant's duties, authorities and responsibilities from those in effect immediately prior to the change in control, (iii) a reduction in the participant's base salary as in effect immediately prior to an agreement to consummate a change in control or (iv) a relocation of the participant's principal place of employment immediately prior to the change in control. In addition, upon the occurrence of certain other transactions defined as a change in control (i.e. (A) any person becomes the beneficial owner of more than 50% of our outstanding Units and our General Partner withdraws or is otherwise removed as our general partner, (B) we are party to a merger, consolidation or other transaction identified under our Partnership Agreement and our General Partner withdraws or is otherwise removed as our general partner, (C) all of our, our General Partner's or certain key affiliates' assets are sold or otherwise disposed of or (D) the complete dissolution or liquidation of us, our General Partner or certain key affiliates), the 2000 LTIP will result in immediate payouts of the then current market value of the phantom units awarded under the plan. These provisions apply to awards made pursuant to the 2000 LTIP prior to February 2005 to Messrs. Mallett, Cockrell, Goodpasture and Brown. For awards made after February 2005 (2006 Awards), there is no provision for accelerated payout upon a change in control. However, see "– 2006 Awards" below for a description of special adjustment provisions in the event of a transaction with Enterprise.

2006 Awards

For any awards made after February 2005 (2006 Awards) under the 1999 Plan, the 2000 LTIP and the 2005 Phantom Unit Plan, effective upon a consolidation, merger or combination of the business of Enterprise and TEPPCO (a "Business Combination"), as determined by EPCO, in its discretion, prior to the end of the performance period, the award shall terminate in full without payment. Upon such Business Combination, the participant will be granted either restricted units or phantom units (as determined by EPCO in its discretion) under an EPCO long-term incentive plan ("EPCO Grant") equal to the number of long-term incentive units granted by us multiplied by the quotient of (i) the closing sales price of our Units on the effective date of the Business Combination divided by (ii) the closing sales price of an Enterprise common unit on that date. For everyone but Mr. Thompson, the EPCO Grant will provide full vesting at the end of its four-year vesting period provided that the participant is still an employee of EPCO or its affiliates on that date. The four-year vesting period for the EPCO Grant will begin on the date the participant received their award under our plan. For Mr. Thompson, the EPCO Grant will provide, to the extent that such EPCO Grant is awarded prior to any one of the following dates, that one-third will vest on April 11, 2007, one-third on April 11, 2008 and the remaining one-third on April 11, 2009, assuming Mr. Thompson's continuing employment through the vesting period. Each of these EPCO Grants will also provide for earlier vesting upon certain qualifying terminations of employment prior to the end of the vesting period consistent with the form of grant agreement adopted by us with respect to such EPCO long-term incentive plan.

Employment Agreements

Prior to its acquisition by DFI, the General Partner had entered into employment agreements with certain executive officers. Mr. Harper's agreement terminated upon his retirement effective February 3, 2006. As of December 31, 2006, only four such employment agreements remained in effect, of which all four were with Named Executive Officers being Messrs. Mallet, Cockrell, Goodpasture and Brown. The agreements could be terminated for death, disability, or for any reason by the General Partner, with or without cause, or the Named Executive Officer. The employment agreements provided that, in the event the executive's employment was terminated upon death or disability or by the General Partner for cause, the executive was entitled only to base salary earned through the date of termination. In the event of termination by the General Partner for any other reason, the executive was entitled to base salary earned through the date of termination plus a lump sum severance payment equal to two times such executive's base annual salary and two times the current target bonus approved by the CEO. The acquisition of our General Partner by an affiliate of EPCO in February 2005 resulted in a change in control for purposes of the employment agreements. The agreements provide that in the event that the executive (in the case of Messrs. Mallet, Cockrell and Brown) was involuntarily terminated or experiences a good reason termination more than twelve months following a change in control, or the executive (in the case of Mr. Goodpasture) was involuntarily terminated or experiences a good reason termination at any time following a change in control, such executive would have been entitled to a lump sum severance payment equal to two times his base annual salary plus two times his current target bonus, plus payment of COBRA premiums (gross-up for taxes) for two years of coverage under our group health plans. In January 2007, the four remaining employment agreements were supplemented ("2007

Supplements") which provide that the employment agreements will automatically terminate on June 1, 2008, in exchange for: (1) a payment (the "Current Award") to Messrs. Mallett, Cockrell, Goodpasture and Brown of $413,700, $489,375, $295,800 and $241,920, respectively, due on or before February 11, 2007; and (ii) if the executive remains employed with EPCO through June 1, 2008, a retention award (the "Retention Award") in an amount equal to such executive's Current Award, due on or before July 31, 2008. In the case of Mr. Mallett, because he is now an EPCO employee, TEPPCO's allocated portion of his Retention Award is $268,905. Each 2007 Supplement also provides that the executive will receive his Retention Award and COBRA insurance for up to 36 months if he is terminated without cause or because of death, a disability, or resigns as a result of relocation, prior to June 1, 2008. We will reimburse EPCO pursuant to the ASA for our allocated portion of the payments and other benefits it provides under the 2007 Supplements. The Current Award and Retention Award payments contemplated by the 2007 Supplements replace and supersede the prior termination payments. EPCO's practice is to not enter into employment agreements with its executive officers. In order to align the compensation structures of the companies under the EPCO umbrella, the 2007 Supplements converted the existing employment agreements with our executive officers into retention plans.

On December 22, 1998, Mr. Ruth and our General Partner entered into an employment agreement, as amended on February 23, 2005, and as amended and assumed by EPCO on June 1, 2005, (collectively, the "Ruth Employment Agreement"). In connection with Mr. Ruth's retirement, the Ruth Employment Agreement was terminated effective February 28, 2006, and he and our General Partner entered into an Agreement and Release, dated January 25, 2006. The Agreement and Release provided for Mr. Ruth to be paid, in lump sum, three times his base salary plus three times his target bonus. Mr. Ruth was also entitled under the agreement to payment of COBRA insurance premiums for up to 36 months (grossed-up for taxes) and payments and benefits in accordance with our General Partner's and EPCO's, as applicable, various plans and programs, including incentive, retirement and benefit plans. The amount of Mr. Ruth's lump sum payment, which included payment of three times his base salary and target bonus, payment of his accrued vacation, payment under the 1994 Long Term Compensation Plan and payment under the 2000 LTIP, was $1.2 million.

Termination or Change in Control Payments

As described above under the descriptions of the 1999 Plan, the 2000 LTIP, the 2005 Phantom Unit Plan and under the heading "Employment Agreements," the following table summarizes potential termination or change in control payments that may be made to Named Executive Officers.

Name	Retention Award Under 2007 Supplements (1)	Change in Control Accelerated 2000 LTIP Awards (2)	Health Care Benefits under 2007 Supplements (1) (4)	Death or Disability Accelerated 1999 Plan Awards	Death Disability or Retirement Accelerated 2000 LTIP Awards	Death or Disability Accelerated 2005 Phantom Unit Plan Awards
Jerry E. Thompson	—	—	—	1,572,090	—	—
William G. Manias	—	—	—	112,868	—	—
Leonard W. Mallett (3)	268,905	134,343	50,017	—	144,521	—
Tracy E. Ohmart	—	—	—	—	—	36,279
J. Michael Cockrell	489,375	152,663	50,017	—	164,876	—
Samuel N. Brown	241,920	91,598	50,017	—	116,024	—
John N. Goodpasture	295,800	134,343	50,017	—	146,556	—

(1) Named Executive Officer is entitled to benefit if he is terminated without cause or because of death, a disability, or resigns as a result of relocation, prior to June 1, 2008.

(2) Named Executive Officer is entitled to this payment in the event of termination without cause or for good reason in connection with a change in control and, in certain cases, on the occurrence of the change in control as described under the heading "2000 LTIP" above. These calculations are based on the assumptions that (i) the change in control was effective December 31, 2006, (ii) the average of the closing price of a Unit over the ten consecutive trading days immediately preceding December 31, 2006 was $40.71, and (iii) the performance percentage applied is 150%.

(3) Amount of Retention Award presented reflects the amount of the total Retention Award allocated to us.

(4) Health care benefits are COBRA payments for 36 months as specified in the 2007 Supplement multiplied by an estimated monthly cost of the benefit.

Director Compensation

At February 28, 2007, our non-employee directors are Messrs. Hutchison, Bracy and Snell. Mr. Thompson receives no additional compensation for serving as a director. Our General Partner is responsible for compensating these directors for their services. The following table presents information regarding compensation to the non-employee directors of our General Partner.

Director	Fees Earned or Paid in Cash ($)	Total ($)
Michael B. Bracy (1)	60,000	60,000
Richard S. Snell	50,000	50,000
Murray H. Hutchison (2)	50,000	50,000

(1) Mr. Bracy is chairman of the AC Committee. On March 10, 2006, our Board elected Mr. Bracy as non-executive Vice Chairman of the Board. He does not receive additional compensation for his service as non-executive Vice Chairman.

(2) On March 10, 2006, our Board elected Mr. Hutchison as non-executive Chairman of the Board. He does not receive additional compensation for his service as non-executive Chairman.

Neither we, our General Partner nor EPCO provide any additional compensation to employees of EPCO who serve as directors of our General Partner. On February 14, 2006, Michael A. Creel, Richard H. Bachmann and W. Randall Fowler, all employees of EPCO, were elected directors of our General Partner. Messrs. Creel, Bachmann and Fowler resigned from their service as directors on December 28, 2006. There were no disagreements between Messrs. Creel, Bachmann, Fowler and us on any matter relating to our operations, policies or practices which resulted in their resignations.

2007 Director Compensation

For the 2007 fiscal year, it is expected that each non-executive director will continue to receive $50,000 annually, paid in monthly installments in advance. The chairman of the Board and the chairman of the AC Committee are also expected to receive an additional $15,000 annually, also paid in monthly installments in advance.

In addition, we expect the AC Committee to authorize the issuance to its members (which constitute the non-executive members of the board of directors) of the following awards under the 2006 LTIP: a number of restricted units having a fair market value of $25,000 on the date of grant, and unit appreciation rights with respect to approximately 25,000 Units (assuming a price of $40.00 per Unit at the time of the grant). Each of the awards will be subject to a ratable vesting schedule over 5 years. Thus, on each anniversary of the grant date, 20% of the restricted units will vest and the unit appreciation rights will become payable with respect to 20% of the Units covered by such award. When the unit appreciation rights become payable, the director will receive a payment in cash or Units (at the discretion of the AC Committee) equal to the fair market value of the Units on the payment date over the fair market value of the Units on the date of grant.

Compensation Committee Interlocks and Insider Participation

The General Partner does not have a compensation committee. The directors of our General Partner do not participate in deliberations concerning the General Partner's executive officer compensation, except for equity awards under our and EPCO's long-term incentive plans. Dan L. Duncan controls EPCO and has ultimate decision-making authority with respect to compensation of our Named Executive Officers and the specific elements of our compensation package. In order to assist Mr. Duncan and EPCO with compensation decisions, Jerry E. Thompson, our CEO, and the Senior Vice President of Human Resources for EPCO formulate preliminary compensation recommendations for all of the Named Executive Officers with the exception of Mr. Thompson. Mr. Duncan then seeks and receives the recommendations of Mr. Thompson. Mr. Duncan, after consulting with the Senior Vice President of Human Resources for EPCO, independently makes compensation decisions with respect to Mr. Thompson. As stated above, the compensation of our Named Executive Officers is paid by EPCO, and we reimburse EPCO for the portion of its compensation expense that is related to our business, pursuant to the ASA. No compensation expense is borne by us with respect to Mr. Duncan.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Equity Compensation Plan Information

EPCO, Inc. 2006 TPP Long-Term Incentive Plan

At a special meeting of our unitholders on December 8, 2006, our unitholders approved the 2006 LTIP, which provides for awards of our Units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 2006 LTIP may be granted in the form of restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. The exercise price of unit options or unit appreciation rights awarded to participants will be determined by the AC Committee (at its discretion) at the date of grant and may be no less than the fair market value of the option award as of the date of grant. The 2006 LTIP will be administered by the AC Committee. 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. As of December 31, 2006, no awards had been granted under the 2006 LTIP. We will reimburse EPCO for the costs allocable to any future 2006 LTIP awards made to employees who work in our business.

The 2006 LTIP may be amended or terminated at any time by the board of directors of EPCO, which is the indirect parent company of our General Partner, or the AC Committee; however, any material amendment, such as a material increase in the number of Units available under the plan or a change in the types of awards available under the plan, would require the approval of at least 50% of our unitholders. The AC Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the 2006 LTIP in specified circumstances. 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 AC Committee.

EPCO, Inc. TPP Employee Unit Purchase Plan

At a special meeting of our unitholders on December 8, 2006, our unitholders approved the EPCO, Inc. TPP Employee Unit Purchase Plan (the "Unit Purchase Plan"), which provides for discounted purchases of our Units by employees of EPCO and its affiliates. Generally, any employee who (1) has been employed by EPCO or any of its designated affiliates for three consecutive months, (2) is a regular, active and full time employee and (3) is scheduled to work at least 30 hours per week is eligible to participate in the Unit Purchase Plan, provided that employees covered by collective bargaining agreements (unless otherwise specified therein) and 5% owners of us, EPCO or any affiliate are not eligible to participate.

A maximum of 1,000,000 Units may be delivered under the Unit Purchase Plan (subject to adjustment as provided in the plan). Units to be delivered under the plan may be acquired by the custodian of the plan in the open market or directly from us, EPCO, any of EPCO's affiliates or any other person; however, it is generally intended that Units are to be acquired from us. Eligible employees may elect to have a designated whole percentage (ranging from 1% to 10%) of their eligible compensation for each pay period withheld for the purchase of Units under the plan. EPCO and its affiliated employers will periodically remit to the custodian the withheld amounts, together with an additional amount by which EPCO will bear approximately 10% of the cost of the Units for the benefit of the participants. Unit purchases will be made following three month purchase periods over which the withheld amounts are to be accumulated. We will reimburse EPCO for all such costs allocated to employees who work in our business.

The plan will be administered by a committee appointed by the Chairman or Vice Chairman of EPCO. The Unit Purchase Plan may be amended or terminated at any time by the board of directors of EPCO, or the Chairman of the Board or Vice Chairman of the Board of EPCO; however, any material amendment, such as a material increase in the number of Units available under the plan or an increase in the employee discount amount, would also require the approval of at least 50% of our unitholders. 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 December 31, 2006, no purchase period has begun and no Units had been purchased under this plan.

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of February 23, 2007, regarding the beneficial ownership of our Units by each person know by us to beneficially own more than 5% of our Units. The information presented in this table is based on information disclosed in the most recent Schedule 13D filed by each of the beneficial owners listed below on December 8, 2006.

Name and Address of Beneficial Owner (1) (2)	Amount and Nature of Beneficial Ownership	Percentage Owned
Dan Duncan LLC (3)	3,204,564	3.6%
DFI Holdings LLC (4)	2,500,000	2.8%
DFI GP Holdings L.P. (5)	2,500,000	2.8%
Duncan Family Interests, Inc. (6)	13,386,711	14.9%
EPCO Holdings, Inc. (7)	13,386,711	14.9%
EPCO, Inc. (8) (10)	13,386,711	14.9%
Dan L. Duncan (9)	16,691,550	18.6%

(1) The address for each beneficial owner listed is this table is 1100 Louisiana, Suite 1000, Houston, Texas 77002.

(2) In connection with the IDR Amendment, we issued 14,091,275 Units to our General Partner, who distributed the Units to its member, which in turn caused them to be distributed to other affiliates of EPCO.

(3) Dan Duncan LLC holds directly 704,564 Units, representing less than 1% of the outstanding Units. Dan Duncan LLC is the sole member of DFI Holdings LLC, which is the 1% general partner of DFI, and owns a 4% limited partner interest in DFI. Therefore, Dan Duncan LLC has shared voting and dispositive power over all of the 2,500,000 Units owned directly by DFI. Mr. Dan L. Duncan is the sole member of Dan Duncan LLC. Therefore, Mr. Duncan has an indirect beneficial ownership interest in the 704,564 Units held directly and the 2,500,000 Units beneficially owned indirectly by Dan Duncan LLC.

(4) As set forth above, DFI Holdings LLC holds no Units directly, but it is the 1% general partner of DFI, and as such has voting and dispositive power over the 2,500,000 Units owned directly by DFI.

(5) As set forth above, DFI holds directly 2,500,000 Units.

(6) Duncan Family Interests, Inc. holds directly 13,386,711 Units; it is a wholly owned subsidiary of EPCO Holdings, Inc., and EPCO Holdings, Inc. is a wholly owned subsidiary of EPCO. Therefore, EPCO and EPCO Holdings, Inc. each have an indirect beneficial ownership interest in the 13,386,711 Units held by Duncan Family Interests, Inc. Mr. Duncan owns approximately 50.4% of the voting stock of EPCO and, accordingly, exercises shared voting and dispositive power with respect to the 13,386,711 Units beneficially owned by EPCO. The remaining shares of EPCO's capital stock are owned primarily by trusts established for the benefit of Mr. Duncan's family.

(7) As set forth above, EPCO Holdings, Inc. has shared voting and dispositive power over the 13,386,711 Units beneficially owned by Duncan Family Interests, Inc.

(8) As set forth above, EPCO has shared voting and dispositive power over the 13,386,711 Units beneficially owned by Duncan Family Interests, Inc.

(9) As set forth above, Mr. Duncan has shared voting and dispositive power over the 13,386,711 Units beneficially owned by EPCO and the 3,204,564 Units beneficially owned by Dan Duncan LLC. Additionally, Mr. Duncan is deemed to be the beneficial owner of the 53,275 Units owned by the Duncan Family 2000 Trust, the beneficiaries of which are the shareholders of EPCO. Mr. Duncan also owns 47,000 Units in his individual capacity.

(10) The 13,386,711 Units beneficially owned by EPCO are pledged to the lenders under the EPCO Holdings, Inc. credit facility as security. The EPCO Holdings, Inc. credit facility contains customary and other events of default.

Security Ownership of Management

The following table sets forth certain information, as of February 27, 2007, concerning the beneficial ownership of Units by each director and Named Executive Officer of the General Partner and by all current directors and executive officers of the General Partner as a group. This information is based on data furnished by the persons named.

Name	Amount and Nature of Beneficial Ownership (1)	Percentage Owned (2)
Michael B. Bracy	4,000	*
Murray H. Hutchison	—	—
Richard S. Snell	—	—
Jerry E. Thompson	10,000	*
Samuel N. Brown	—	—
J. Michael Cockrell	5,000	*
John N. Goodpasture	2,000	*
Leonard W. Mallet	1,178	*
William G. Manias	1,000	*
Lee W. Marshall, Sr. (3)	—	—
Tracy E. Ohmart	—	—
James C. Ruth (4)	5,000	*
C. Bruce Shaffer (5)	—	—
All directors and current executive officers (consisting of 9 people)	22,050	*

(1) The persons named above have sole voting and investment power over the Units reported. Includes Units that the named person has the right to acquire within 60 days.

(2) An asterisk in the column indicates that the beneficial owner holds less than 1% of the class.

(3) Mr. Marshall passed away on March 3, 2006. Beneficial ownership is presented as of December 31, 2005 for Mr. Marshall.

(4) Mr. Ruth retired effectived February 28, 2006.

(5) Mr. Shaffer retired effective August 31, 2006.

Pledge of Interests of our General Partner

The ownership interests in us that are owned or controlled by EPCO and its affiliates, which include all of the membership interests in our General Partner, are pledged as security under the credit facility of an affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, Enterprise and us. If EPCO were to default under the credit facility, its lender banks could own our General Partner.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

We do not have any employees. We are managed by our General Partner. All of our management, administrative and operating functions are performed by employees of EPCO, pursuant to the ASA. We reimburse EPCO for the allocated costs of its employees who perform operating functions for us and for costs related to its other management and administrative employees (see Note 1 in the Notes to the Consolidated Financial Statements).

The following information summarizes our business relationships and related transactions with EPCO and its affiliates, including entities controlled by Dan L. Duncan, during the year ended December 31, 2006. We have also provided information regarding our business relationships and transactions with our unconsolidated affiliates.

For information regarding our related party transactions in general, please read Note 16 of the Notes to Consolidated Financial Statements included under Item 8 of this Report.

Interests of the General Partner in the Partnership

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

	Unitholders	General Partner
Quarterly Cash Distribution per Unit:		
Up to Minimum Quarterly Distribution ($0.275 per Unit)	98%	2%
First Target – $0.276 per Unit up to $0.325 per Unit	85%	15%
Over First Target – Cash distributions greater than $0.325 per Unit (1)	75%	25%

(1) Effective December 8, 2006, upon approval of our unitholders, the 50%/50% distribution tier was eliminated in exchange for the issuance of 14,091,275 Units to the General Partner (see Items 1 and 2. Business and Properties, "– 2006 Developments").

During the year ended December 31, 2006, distributions paid to the General Partner totaled $81.9 million, including incentive distributions of $77.9 million.

General Partner's Incentive Distribution Rights

On December 8, 2006, our Partnership Agreement was amended and restated, among other things, to reduce the General Partner's maximum percentage interest in our quarterly distributions from 50% to 25% with respect to that portion of our quarterly cash distribution to partners that exceeds $0.325 per Unit. In exchange for the agreement to reduce its maximum percentage interest in our quarterly distributions, our General Partner received approximately 14.1 million newly-issued Units. These transactions were undertaken in connection with a proposal submitted by EPCO to the AC Committee of the Board of our General Partner in April 2006. For additional discussion of the changes to our Partnership Agreement, please read Items 1 and 2. Business and Properties – 2006 Developments, "– Special Unitholder Meeting," which is incorporated herein by this reference.

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;
- DFI, which owns and controls our General Partner;
- Enterprise Products Partners L.P., which is controlled by affiliates of EPCO;
- Duncan Energy Partners L.P., which is controlled by affiliates of EPCO; and
- Enterprise Gas Processing LLC, controlled by affiliates of EPCO, our joint venture partner in Jonah.

EPCO, a private company controlled by Dan L. Duncan, also owns DFI, which owns and controls our General Partner. DFI 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 and of our General Partner are employees of EPCO (see Item 10 of this Report).

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 depends on the cash distributions it receives from our General Partner and other investments to fund its other operations and to meet its debt obligations. We paid cash distributions of $81.9 million and $73.2 million during the years ended December 31, 2006 and 2005, to our General Partner.

The ownership interests in us that are owned or controlled by EPCO and its affiliates, which include all of the membership interests in our General Partner, are pledged as security under the credit facility of an affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, Enterprise and us. If EPCO were to default under the credit facility, its lender banks could own our General Partner.

Unless noted otherwise, our agreements with EPCO are not the result of arm’s length transactions. As a result, we cannot provide assurance that the terms and provisions of such agreements are at least as favorable to us as we could have obtained from unaffiliated third parties.

Administrative Services Agreement

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the ASA. We and our General Partner, Enterprise and its general partner, Enterprise GP Holdings and its general partner, DEP and its general partner and certain affiliated entities are parties to the ASA. The significant terms of the ASA are as follows:

- EPCO provides administrative, management, engineering and operating services as may be necessary to manage and operate our business, properties and assets (in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.
- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses (direct and indirect) incurred by EPCO which are directly or indirectly related to our business or activities (including EPCO expenses reasonably allocated to us). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.
- EPCO allows us to participate as named insureds in its overall insurance program with the associated costs being allocated to us.

Our operating costs and expenses for the years ended December 31, 2006 and 2005 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets.

Likewise, our general and administrative costs for the years ended December 31, 2006 and 2005 include amounts we reimburse to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity's business and affairs).

EPCO and its affiliates have no obligation to present business opportunities to us or our Operating Partnerships, and we and our Operating Partnerships have no obligation to present business opportunities to EPCO and its affiliates. However, the ASA requires that business opportunities offered to or discovered by EPCO, which controls both us and our affiliates and Enterprise and it affiliates, be offered first to certain Enterprise affiliates before they may be pursued by EPCO and its other affiliates or offered to us.

On February 28, 2007, due to the substantial completion of inquires by the FTC into EPCO's acquisition of our General Partner, the parties to the ASA amended it to remove Exhibit B thereto, which had been adopted to address matters the parties anticipated the FTC may consider in its inquiry. Exhibit B had set forth certain separateness and screening policies and procedures among the parties that became inapposite upon the issuance of the FTC's order in connection with the inquiry or were already otherwise reflected in applicable FTC, SEC, NYSE or other laws, standards or governmental regulations. For further discussion of the FTC investigation, please see Item 3. Legal Proceedings.

Transactions between EPCO and affiliates and us

The following table presents a detailed statement of transactions between EPCO and affiliates and us during the year ended December 31, 2006 (in millions):

Revenues from EPCO and affiliates:	
Sales of petroleum products (1)	$ 3.2
Transportation — NGLs (2)	10.2
Transportation — LPGs (3)	3.6
Other operating revenues (4)	1.5
Costs and Expenses from EPCO and affiliates:	
Payroll, administrative and other (5) (6)	136.9
Purchases of petroleum products (7)	41.8

(1) Includes Jonah NGL sales through July 31, 2006 of $2.9 million to Enterprise Gas Processing, LLC and $0.3 million in sales from LSI to various EPCO affiliates.

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

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

(4) Includes other operating revenues on the TE Products pipeline.

(5) Includes payroll, payroll related expenses, administrative expenses, including reimbursements related to employee benefits and employee benefit plans, incurred in managing us and our subsidiaries in accordance with the ASA, and other operating expenses.

(6) Includes $15.8 million of insurance expense allocated to us by EPCO. The majority of our insurance coverage, including property, liability, business interruption, auto and directors and officers' liability insurance, was obtained through EPCO.

(7) Includes TCO purchases of condensate of $41.6 million, Jonah processing fees through July 31, 2006 of $0.1 million and $0.1 million of expenses related to LSI's use of an affiliate of EPCO as a transporter.

The following table summarizes the related party balances with EPCO and affiliates at December 31, 2006 (in millions):

Accounts receivable, related party (1)	$ 0.3
Gas imbalance receivable	1.3
Insurance reimbursement receivable	1.4
Accounts payable, related party (2)	26.4
Deferred revenue, related party	0.3
Long-term payable (3)	1.8

(1) Relates to sales and transportation services provided to EPCO and affiliates.

(2) Relates to direct payroll, payroll related costs and other operational related charges from EPCO and afffiliates.

(3) Relates to our share of EPCO's Oil Insurance Limited insurance program retrospective premiums obligation.

Sale of Pioneer Plant

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

Jonah Joint Venture

On August 1, 2006, Enterprise, through its affiliate, Enterprise Gas Processing, LLC, became our joint venture partner by acquiring an interest in Jonah, the general partnership through which we owned the Jonah system. Prior to entering into the Jonah joint venture, Enterprise had managed the construction of the Phase V expansion and funded the initial costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and Enterprise plan to continue the Phase V expansion, which is expected to increase the system capacity of the Jonah system from 1.5 Bcf/d to approximately 2.3 Bcf/d and to significantly reduce system operating pressures, which is anticipated to lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is expected to increase the system gathering capacity to approximately 2.0 Bcf/d, is scheduled to be completed in the first quarter of 2007. The second portion of the expansion is expected to be completed by the end of 2007. The anticipated cost of the Phase V expansion is expected to be approximately $444.0 million. We expect to reimburse Enterprise for approximately 50% of these costs. To the extent the costs exceed an agreed upon base cost estimate of $415.2 million, we and Enterprise will each pay our respective ownership share (approximately 80% and 20%, respectively) of such costs.

Enterprise will continue to manage the Phase V construction project. We are entitled to all distributions from the joint venture until specified milestones are achieved, at which point Enterprise will be entitled to receive approximately 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. From August 1, 2006, we and Enterprise equally share the costs of the Phase V expansion. After subsequent milestones are achieved, we and Enterprise will share distributions based on a formula that takes into account the capital contributions of the parties, including expenditures by us prior to the expansion. Based on this formula in the partnership agreement, we expect to own an interest in Jonah of approximately 80%, with Enterprise owning the remaining 20% and serving as operator, with further costs being allocated based on such ownership interests. The joint venture is governed by a management committee comprised of two representatives approved by Enterprise and two representatives approved by us, each with equal voting power. This transaction was reviewed and recommended for approval by the AC Committee.

In conjunction with the formation of the joint venture, we have agreed to indemnify Enterprise 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 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 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 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 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.

Other Transactions

On October 6, 2006, we sold certain crude oil pipeline assets and refined products pipeline assets in the Houston, Texas area, to an affiliate of Enterprise for approximately $11.7 million. These assets, which have been idle since acquisition, were part of the assets acquired by us in 2005 from Genco and BP. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of these pipeline assets at September 30, 2006, was approximately $6.0 million.

On November 1, 2006, we announced plans to construct a new 20-inch diameter lateral pipeline to connect our mainline system to the Enterprise and MB Storage facilities at Mont Belvieu, Texas, at a cost of approximately $8.6 million. The new connection, which provides delivery from Enterprise of propane into our system at full line flow rates, complements our current ability to source product from MB Storage. The new connection also offers the ability to deliver other liquid products such as butanes and natural gasoline from Enterprise's storage facilities into our system at reduced flow rates until enhancements can be made. The capability to deliver butanes and natural gasoline from MB Storage at full flow rates is not expected to be impacted. Construction of the new connection was completed and placed in service in December 2006. This new pipeline replaces a 10-mile, 18-inch segment of pipeline that we sold to an Enterprise affiliate on January 23, 2007 for approximately $8.0 million. This asset was part of our Downstream Segment and had a net book value of approximately $2.5 million.

We have entered into a lease with DEP, for a 12-mile, 10-inch interconnecting pipeline extending from Pasadena, Texas to Baytown, Texas. The primary term of this lease will expire on September 15, 2007, and will continue on a month-to-month basis subject to termination by either party upon 60 days' notice. The annual lease revenue under this agreement is approximately $0.1 million.

Review and Approval of Transactions with Related Parties

Our Partnership Agreement and AC Committee Charter set forth policies and procedures for the review, recommendation or approval of certain transactions with persons affiliated with or related to us. As further described below, our Partnership Agreement sets forth procedures by which related party transactions and conflicts of interest may be approved or resolved by the General Partner or the AC Committee. In submitting a matter to the AC Committee, the Board on behalf of the General Partner, the Operating Partnerships or us may charge the committee with reviewing the transaction and providing the Board a recommendation, or it may delegate to the committee the power to approve the matter.

The AC Committee Charter provides that it is the responsibility of the AC Committee to:

- receive, consider, reject and pass on the fairness and reasonableness of any transaction or matter involving a conflict of interest between our General Partner and its affiliates, on the one hand, and us or our subsidiaries, on the other, including without limitation asset sales, operating or support services agreements and any other material contractual arrangements,
- evaluate the fairness and reasonableness to us and approve or reject the issuance and pricing of any equity securities by us,
- establish procedures for determining the fairness and reasonableness of any affiliate transactions involving product exchanges or loans, without direct AC Committee action and
- ensure that we and the General Partner have an appropriate policy on potential conflicts of interest, including, but not limited to, policies on (1) loans to officers and employees (if allowed by law), (2) related-party transactions (including any dealings with directors, officers or employees), and (3) such other transactions that could have the appearance of a potential conflict of interest.

The ASA governs numerous day-to-day transactions between us and our subsidiaries and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our subsidiaries and our reimbursement of costs for those services. The AC Committee reviewed and recommended the ASA, and the Board approved it upon receiving such recommendation. Affiliate transactions involving product exchanges or loans are subject to procedures of our Risk Management Committee, which is comprised, in part, of senior executives of our General Partner. The Risk Management Committee provides recommendations to the AC Committee regarding the approval of these transactions.

Under our Board-approved management authorization policy, our General Partner's officers have authorization limits for purchases and sales of assets, capital expenditures, commercial and financial transactions and legal agreements that ultimately limit the ability of executives of our General Partner to enter into transactions involving capital expenditures in excess of $15.0 million without Board approval. This policy covers all transactions, including transactions with related parties. For example, under this policy, the chairman may approve capital expenditures or the sale or other disposition of our assets up to a $15.0 million limit and the CEO may approve capital expenditures or the sale or other disposition of our assets up to $5.0 million. These officers have also been granted full approval authority for commercial, financial and service contracts.

Under our Partnership Agreement, unless otherwise expressly provided therein or in the partnership agreements of our Operating Partnerships, whenever a potential conflict of interest exists or arises between our General Partner or any of its affiliates, on the one hand, and us, any of our subsidiaries or any partner, on the other hand, any resolution or course of action by the General Partner or its affiliates in respect of such conflict of interest is permitted and deemed approved by all of our partners, and will not constitute a breach of our Partnership Agreement, any of the operating partnership agreements or any agreement contemplated by such agreements, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the Partnership Agreement is deemed to be, fair and reasonable to us; *provided* that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by "Special Approval" (i.e., by a majority of the members of the AC Committee), or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from unrelated third parties.

In connection with its resolution of any conflict of interest, our Partnership Agreement authorizes the AC Committee (in connection with Special Approval) to consider:

- the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;
- the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us);
- any customary or accepted industry practices and any customary or historical dealings with a particular person;
- any applicable generally accepted accounting or engineering practices or principles; and
- such additional factors as the AC Committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

The review and work performed by the AC Committee with respect to a transaction varies depending upon the nature of the transaction and the scope of the committee's charge. Examples of functions the AC Committee may, as it deems appropriate, perform in the course of reviewing a transaction include (but are not limited to):

- assessing the business rationale for the transaction;
- reviewing the terms and conditions of the proposed transaction, including consideration and financing requirements, if any;
- assessing the effect of the transaction on our earnings and distributable cash flow per Unit, and on our results of operations, financial condition, properties or prospects;
- conducting due diligence, including by interviews and discussions with management and other representatives and by reviewing transaction materials and findings of management and other representatives;
- considering the relative advantages and disadvantages of the transactions to the parties;
- engaging third party financial advisors to provide financial advice and assistance, including by providing fairness opinions if requested;

- engaging legal advisors;
- evaluating and negotiating the transaction and recommending for approval or approving the transaction, as the case may be.

Nothing contained in the Partnership Agreement requires the AC Committee to consider the interests of any person other than the Partnership. In the absence of bad faith by the AC Committee or our General Partner, the resolution, action or terms so made, taken or provided (including granting Special Approval) by the AC Committee or our General Partner with respect to such matter are conclusive and binding on all persons (including all of our partners) and do not constitute a breach of the Partnership Agreement, or any other agreement contemplated thereby, or a breach of any standard of care or duty imposed in the Partnership Agreement or under the Delaware Revised Uniform Limited Partnership Act or any other law, rule or regulation. The Partnership Agreement provides that it is presumed that the resolution, action or terms made, taken or provided by the AC Committee or our General Partner were not made, taken or provided in bad faith, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or us challenging such resolution, action or terms, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Relationships with Unconsolidated Affiliates

The following information summarizes significant related party transaction amounts with Centennial, MB Storage, Seaway and Jonah during 2006:

- In January 2003, TE Products entered into a pipeline capacity lease agreement with Centennial for a period of five years that contains a minimum throughput requirement. For the year ended December 31, 2006, TE Products incurred $5.6 million of rental charges related to the lease of pipeline capacity on Centennial.
- We perform certain management services for Centennial, MB Storage and Seaway. During 2006, these affiliates paid us $20.4 million for such services, including payroll and payroll related expenses.
- TCO purchases NGLs from Jonah as part of its crude oil marketing activities. For the year ended December 31, 2006, TCO incurred $2.2 million in purchases from Jonah related to the crude oil marketing activities.

For additional discussion of contributions to and distributions from our unconsolidated affiliates, see Note 9 in the Notes to the Consolidated Financial Statements.

Director Independence

Messrs. Bracy, Hutchison and Snell have been determined to be independent under the applicable NYSE listing standards and are independent under the rules of the SEC applicable to audit committees. For a discussion of independence standards applicable to the Board and certain transactions, relationships or arrangements considered by the Board in making its independence determinations, please refer to Item 10. Directors, Executive Officers and Corporate Governance, “—Partnership Management”, “—Corporate Governance” and “—Audit, Conflicts and Governance Committee”, which are incorporated into this item by reference.

Item 14. ***Principal Accounting Fees and Services***

Appointment of Independent Registered Public Accountant

The AC Committee has appointed Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively “Deloitte & Touche”) as our principal accountant to conduct the audit of our financial statements for the fiscal year ended December 31, 2006. KPMG served as our independent auditors for the fiscal year ended December 31, 2005.

Audit Fees

The aggregate fees billed by Deloitte & Touche and KPMG for professional services rendered for the audit of our financial statements for the years ended December 31, 2006 and 2005, and for other services rendered during those periods on our behalf were as follows (in thousands):

Type of Fee	Deloitte & Touche For Year Ended December 31, 2006	Deloitte & Touche For Year Ended December 31, 2005	KPMG For Year Ended December 31, 2006	KPMG For Year Ended December 31, 2005
Audit Fees (1)	$ 1,706	$ —	$ 266	$ 1,773
Audit Related Fees (2)	—	—	—	26
Tax Fees (3)	107	—	—	—
All Other Fees (4)	—	—	—	—
Total	$ 1,813	$ —	$ 266	$ 1,799

(1) Audit fees include fees for the audits of the consolidated financial statements as well as for the audit of internal control over financial reporting.

(2) Audit related fees consist principally of fees for audits of financial statements of certain employee benefit plans and certain internal control documentation assistance.

(3) Tax Fees consist of fees for sales and use tax consultation and tax compliance services.

(4) All other fees represent amounts we were billed in each of the years presented for services not classified under the other categories listed in the table above. No such services were rendered by Deloitte & Touche and KPMG during the last two years.

Procedures for Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accountant

Pursuant to its charter, the AC Committee is responsible for reviewing and approving, in advance, any audit and any permissible non-audit engagement or relationship between us and our independent registered public accountants. On April 6, 2006, the AC Committee pre-approved Deloitte & Touche and all related fees to conduct the audit of our financial statements for the year ending December 31, 2006. KPMG's engagement to conduct the audit of our financial statements for the year ended December 31, 2005, and all related fees were pre-approved by the AC Committee on April 25, 2005.

Additionally, all permissible non-audit engagements with Deloitte & Touche and KPMG have been reviewed and approved by the AC Committee, pursuant to pre-approval policies and procedures established by the AC Committee. In connection with its oversight responsibilities, the Committee has adopted a pre-approval policy regarding any services proposed to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other.

In general, as services are required, management and Deloitte & Touche submit a detailed proposal to the AC Committee discussing the reasons for the request, the scope of work to be performed, and an estimate of the fee to be charged by Deloitte & Touche for such work. The AC Committee discusses the request with management and Deloitte & Touche, and if the work is deemed necessary and appropriate for Deloitte & Touche to perform, approves the request subject to the fee amount presented (the initial "pre-approved" fee amount). As part of these discussions, the AC Committee must determine whether or not the proposed services are permitted under the rules and regulations concerning auditor independence under the Sarbanes-Oxley Act of 2002 as well as rules of the American Institute of Certified Public Accountants. If at a later date, it appears that the initial pre-approved fee amount may be insufficient to complete the work, then management and Deloitte & Touche must present a request to the AC Committee to increase the approved amount and the reasons for the increase.

Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for services outside of the pre-approved amounts. On a quarterly basis, the AC Committee is provided a schedule showing Deloitte & Touche's pre-approved amounts compared to actual fees billed for each of the primary service categories. The Committee's pre-approval process helps to ensure the independence of our principal accountant from management.

In order for Deloitte & Touche to maintain its independence, we are prohibited from using them to perform general bookkeeping, management or human resource functions, and any other service not permitted by the Public Company Accounting Oversight Board. The AC Committee's pre-approval policy also precludes Deloitte & Touche from performing any of these services for us.

PART IV

Item 15. *Exhibits, Financial Statement Schedules.*

(a) The following documents are filed as a part of this Report:

(1) Financial Statements: See Index to Consolidated Financial Statements on page F-1 of this Report for financial statements filed as part of this Report.

(2) Financial Statement Schedules: Consolidated Financial Statements of Jonah Gas Gathering Company and Subsidiary as of and for the year ended December 31, 2006.

(3) Exhibits.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of TEPPCO Partners, L.P. (Filed as Exhibit 3.2 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
3.2	Third Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P., dated September 21, 2001 (Filed as Exhibit 3.7 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
3.3	Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated March 31, 2000 (Filed as Exhibit 3.3 to Form 10-Q/A of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
3.4	Amendment to Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated March 22, 2005 (Filed as Exhibit 3.4 to Form 10-Q/A of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
3.5	Amendment to Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated June 15, 2006, but effective as of February 24, 2005 (Filed as Exhibit 3.1 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on June 16, 2006.
3.6	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).
4.1	Form of Certificate representing Limited Partner Units (Filed as Exhibit 4.1 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
4.2	Form of Indenture between TE Products Pipeline Company, Limited Partnership and The Bank of New York, as Trustee, dated as of January 27, 1998 (Filed as Exhibit 4.3 to TE Products Pipeline Company, Limited Partnership's Registration Statement on Form S-3 (Commission File No. 333-38473) and incorporated herein by reference).

Exhibit Number	Description
4.3	Form of Certificate representing Class B Units (Filed as Exhibit 4.3 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1998 and incorporated herein by reference).
4.4	Form of Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.2 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.5	First Supplemental Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.3 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.6	Second Supplemental Indenture, dated as of June 27, 2002, among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, and Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as trustee (Filed as Exhibit 4.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
4.7	Third Supplemental Indenture among TEPPCO Partners, L.P. as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as trustee, dated as of January 30, 2003 (Filed as Exhibit 4.7 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
4.8	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).
10.1+	Duke Energy Corporation Executive Savings Plan (Filed as Exhibit 10.7 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.2+	Duke Energy Corporation Executive Cash Balance Plan (Filed as Exhibit 10.8 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.3+	Duke Energy Corporation Retirement Benefit Equalization Plan (Filed as Exhibit 10.9 to Form 10-K for TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.4+	Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan executed on March 8, 1994 (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1994 and incorporated herein by reference).
10.5+	Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan, Amendment 1, effective January 16, 1995 (Filed as Exhibit 10.12 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 1999 and incorporated herein by reference).
10.6+	Form of Employment Agreement between the Company and Thomas R. Harper, Charles H. Leonard, James C. Ruth, John N. Goodpasture, Leonard W. Mallett, Stephen W. Russell, C. Bruce Shaffer, and Barbara A. Carroll (Filed as Exhibit 10.20 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1998 and incorporated herein by reference).

Exhibit Number	Description
10.7	Services and Transportation Agreement between TE Products Pipeline Company, Limited Partnership and Fina Oil and Chemical Company, BASF Corporation and BASF Fina Petrochemical Limited Partnership, dated February 9, 1999 (Filed as Exhibit 10.22 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1999 and incorporated herein by reference).
10.8	Call Option Agreement, dated February 9, 1999 (Filed as Exhibit 10.23 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1999 and incorporated herein by reference).
10.9+	Form of Employment and Non-Compete Agreement between the Company and J. Michael Cockrell effective January 1, 1999 (Filed as Exhibit 10.29 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.10+	Texas Eastern Products Pipeline Company Non-employee Directors Unit Accumulation Plan, effective April 1, 1999 (Filed as Exhibit 10.30 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.11+	Texas Eastern Products Pipeline Company Non-employee Directors Deferred Compensation Plan, effective November 1, 1999 (Filed as Exhibit 10.31 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.12+	Texas Eastern Products Pipeline Company Phantom Unit Retention Plan, effective August 25, 1999 (Filed as Exhibit 10.32 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.13+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan, Amendment and Restatement, effective January 1, 2000 (Filed as Exhibit 10.28 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2000 and incorporated herein by reference).
10.14+	TEPPCO Supplemental Benefit Plan, effective April 1, 2000 (Filed as Exhibit 10.29 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2000 and incorporated herein by reference).
10.15+	Employment Agreement with Barry R. Pearl (Filed as Exhibit 10.30 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2001 and incorporated herein by reference).
10.16	Second Amended and Restated Agreement of Limited Partnership of TE Products Pipeline Company, Limited Partnership, dated September 21, 2001 (Filed as Exhibit 3.8 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
10.17	Amended and Restated Agreement of Limited Partnership of TCTM, L.P., dated September 21, 2001 (Filed as Exhibit 3.9 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
10.18	Contribution, Assignment and Amendment Agreement among TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., Texas Eastern Products Pipeline Company, LLC, and TEPPCO GP, Inc., dated July 26, 2001 (Filed as Exhibit 3.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2001 and incorporated herein by reference).
10.19	Certificate of Formation of TEPPCO Colorado, LLC (Filed as Exhibit 3.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1998 and incorporated herein by reference).
10.20	Agreement of Limited Partnership of TEPPCO Midstream Companies, L.P., dated September 24, 2001 (Filed as Exhibit 3.10 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
10.21	Agreement of Partnership of Jonah Gas Gathering Company dated June 20, 1996 as amended by that certain Assignment of Partnership Interests dated September 28, 2001

Exhibit Number	Description
	(Filed as Exhibit 10.40 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2001 and incorporated herein by reference).
10.22	Unanimous Written Consent of the Board of Directors of TEPPCO GP, Inc. dated February 13, 2002 (Filed as Exhibit 10.41 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2001 and incorporated herein by reference).
10.23	Amended and Restated Credit Agreement among TEPPCO Partners, L.P. as Borrower, SunTrust Bank, as Administrative Agent and LC Issuing Bank and Certain Lenders, as Lenders dated as of March 28, 2002 ($500,000,000 Revolving Facility) (Filed as Exhibit 10.45 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2002 and incorporated herein by reference).
10.24	Purchase and Sale Agreement between Burlington Resources Gathering Inc. as Seller and TEPPCO Partners, L.P., as Buyer, dated May 24, 2002 (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of July 2, 2002 and incorporated herein by reference).
10.25	Amendment, dated as of June 27, 2002 to the Amended and Restated Credit Agreement among TEPPCO Partners, L.P., as Borrower, SunTrust Bank, as Administrative Agent, and Certain Lenders, dated as of March 28, 2002 ($500,000,000 Revolving Credit Facility) (Filed as Exhibit 99.3 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of July 2, 2002 and incorporated herein by reference).
10.26	Agreement of Limited Partnership of Val Verde Gas Gathering Company, L.P., dated May 29, 2002 (Filed as Exhibit 10.48 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
10.27+	Texas Eastern Products Pipeline Company, LLC 2002 Phantom Unit Retention Plan, effective June 1, 2002 (Filed as Exhibit 10.49 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
10.28+	Amended and Restated TEPPCO Supplemental Benefit Plan, effective November 1, 2002 (Filed as Exhibit 10.44 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.29+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan, Second Amendment and Restatement, effective January 1, 2003 (Filed as Exhibit 10.45 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.30+	Amended and Restated Texas Eastern Products Pipeline Company, LLC Management Incentive Compensation Plan, effective January 1, 2003 (Filed as Exhibit 10.46 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.31+	Amended and Restated TEPPCO Retirement Cash Balance Plan, effective January 1, 2002 (Filed as Exhibit 10.47 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.32	Formation Agreement between Panhandle Eastern Pipe Line Company and Marathon Ashland Petroleum LLC and TE Products Pipeline Company, Limited Partnership, dated as of August 10, 2000 (Filed as Exhibit 10.48 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.33	Amended and Restated Limited Liability Company Agreement of Centennial Pipeline LLC dated as of August 10, 2000 (Filed as Exhibit 10.49 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.34	Guaranty Agreement, dated as of September 27, 2002, between TE Products Pipeline Company, Limited Partnership and Marathon Ashland Petroleum LLC for Note Agreements of Centennial Pipeline LLC (Filed as Exhibit 10.50 to Form 10-K of

Exhibit Number	Description
	TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.35	LLC Membership Interest Purchase Agreement By and Between CMS Panhandle Holdings, LLC, As Seller and Marathon Ashland Petroleum LLC and TE Products Pipeline Company, Limited Partnership, Severally as Buyers, dated February 10, 2003 (Filed as Exhibit 10.51 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.36	Joint Development Agreement between TE Products Pipeline Company, Limited Partnership and Louis Dreyfus Plastics Corporation dated February 10, 2000 (Filed as Exhibit 10.52 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2003 and incorporated herein by reference).
10.37	Credit Agreement among TEPPCO Partners, L.P. as Borrower, SunTrust Bank as Administrative Agent and LC Issuing Bank and The Lenders Party Hereto, as Lenders, dated as of June 27, 2003 ($550,000,000 Revolving Facility) (Filed as Exhibit 10.52 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2003 and incorporated herein by reference).
10.38	Agreement of Limited Partnership of Mont Belvieu Storage Partners, L.P. dated effective January 21, 2003 (Filed as Exhibit 10.53 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2003 and incorporated herein by reference).
10.39	Letter of Agreement Clarifying Rights and Obligations of the Parties Under the Mont Belvieu Storage Partners, L.P., Partnership Agreement and the Mont Belvieu Venture, LLC, LLC Agreement, dated October 25, 2003 (Filed as Exhibit 10.54 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2003 and incorporated herein by reference).
10.40	Amended and Restated Credit Agreement among TEPPCO Partners, L.P., as Borrower, SunTrust Bank, as Administrative Agent and LC Issuing Bank and The Lenders Party Hereto, as Lenders dated as of October 21, 2004 ($600,000,000 Revolving Facility) (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of October 21, 2004 and incorporated herein by reference).
10.41+	Texas Eastern Products Pipeline Company Amended and Restated Non-employee Directors Deferred Compensation Plan, effective April 1, 2002 (Filed as Exhibit 10.42 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2004 and incorporated herein by reference).
10.42+	Texas Eastern Products Pipeline Company Second Amended and Restated Non-employee Directors Unit Accumulation Plan, effective January 1, 2004 (Filed as Exhibit 10.41 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2004 and incorporated herein by reference).
10.43	First Amendment to Amended and Restated Credit Agreement, dated as of February 23, 2005, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A. and KeyBank, N.A. as Co-Documentation Agents (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 24, 2005 and incorporated herein by reference).
10.44+	Supplemental Agreement to Employment Agreement between the Company and Barry R. Pearl dated as of February 23, 2005 (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).
10.45+	Supplemental Agreement to Employment and Non-Compete Agreement between the Company and J. Michael Cockrell dated as of February 23, 2005 (Filed as Exhibit 10.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).
10.46+	Supplemental Form Agreement to Form of Employment Agreement between the Company and John N. Goodpasture, Stephen W. Russell, C. Bruce Shaffer and Barbara A. Carroll dated as of February 23, 2005 (Filed as Exhibit 10.3 to Form 10-Q of TEPPCO

Table of Contents

Exhibit Number	Description
	Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).
10.47+	Supplemental Form Agreement to Form of Employment and Agreement between the Company and Thomas R. Harper, Charles H. Leonard, James C. Ruth and Leonard W. Mallett dated as of February 23, 2005 (Filed as Exhibit 10.4 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).
10.48+	Amendments to the TEPPCO Retirement Cash Balance Plan and the TEPPCO Supplemental Benefit Plan dated as of May 27, 2005 (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, 2005 and incorporated herein by reference).
10.49+	Agreement and Release between Charles H. Leonard and Texas Eastern Products Pipeline Company, LLC dated as of July 11, 2005 (Filed as Exhibit 10.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
10.50	Third Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated August 15, 2005, but effective as of February 24, 2005 (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated August 19, 2005 and incorporated herein by reference).
10.51	Second Amendment to Amended and Restated Credit Agreement, dated as of December 13, 2005, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A. and KeyBank, N.A., as Co-Documentation Agents (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of December 13, 2005 and incorporated herein by reference).
10.52+	Agreement and Release between Barry R. Pearl and Texas Eastern Products Pipeline Company, LLC dated as of December 30, 2005 (Filed as Exhibit 10.52 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2005 and incorporated herein by reference).
10.53+	Agreement and Release between James C. Ruth and Texas Eastern Products Pipeline Company, LLC dated as of January 25, 2006 (Filed as Exhibit 10.53 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2005 and incorporated herein by reference).
10.54	Letter of Intent between TEPPCO Partners, L.P. and Enterprise Products Operating, L.P. dated February 13, 2006 (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated February 17, 2006 and incorporated herein by reference).
10.55+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan Notice of 2006 Award (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, 2006 and incorporated herein by reference).
10.56+	Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan Notice of 2006 Award (Filed as Exhibit 10.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2006 and incorporated herein by reference).
10.57	Third Amendment to Amended and Restated Credit Agreement, dated as of July 31, 2006, by and among TEPPCO Partners, L.P., the Borrower, several banks and other

Exhibit Number	Description
	financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders and as the LC Issuing Bank, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A., and The Royal Bank of Scotland Plc, as Co-Documentation Agents (Filed as Exhibit 10.3 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.58	Amended and Restated Partnership Agreement of Jonah Gas Gathering Company dated as of August 1, 2006 (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.59	Contribution Agreement among TEPPCO GP, Inc., TEPPCO Midstream Companies, L.P. and Enterprise Gas Processing, LLC dated as of August 1, 2006 (Filed as Exhibit 10.2 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.60	Transaction Agreement by and between TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC dated as of September 5, 2006 (Filed as Exhibit 10 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed September 12, 2006 and incorporated herein by reference).
10.61	Fourth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., Duncan Energy Partners L.P., DEP Holdings, LLC, DEP Operating Partnership, L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated January 30, 2007, but effective as of February 5, 2007 (Filed as Exhibit 10.18 to Current Report on Form 8-K of Duncan Energy Partners L.P. (Commission File No. 1-33266) filed February 5, 2007 and incorporated herein by reference).
10.62+*	Form of Supplemental Agreement to Employment Agreement between Texas Eastern Products Pipeline Company, LLC and assumed by EPCO, Inc., and John N. Goodpasture, Samuel N. Brown and J. Michael Cockrell.
10.63+*	Form of Retention Agreement.
10.64*	Amended and Restated Agreement of Limited Partnership of TEPPCO Midstream Companies, L.P. by and between TEPPCO GP, Inc. and TEPPCO Partners, L.P. dated as of February 27, 2007.
10.65*	Second Amended and Restated Agreement of Limited Partnership of TCTM, L.P. by and between TEPPCO GP, Inc. and TEPPCO Partners, L.P. dated as of February 27, 2007.
10.66*	Third Amended and Restated Agreement of Limited Partnership of TE Products Pipeline Company, Limited Partnership by and between TEPPCO GP, Inc. and TEPPCO Partners, L.P. dated as of February 27, 2007.
10.67	First Amendment to the Fourth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., Duncan Energy Partners L.P., DEP Holdings, LLC, DEP Operating Partnership, L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated February 28, 2007 (Filed as Exhibit 10.8 to Form 10-K of Enterprise Products Partners L.P. (Commission File No. 1-14323) for the year ended December 31, 2006 and incorporated herein by reference).
12.1*	Statement of Computation of Ratio of Earnings to Fixed Charges.
16	Letter from KPMG LLP to the Securities and Exchange Commission dated April 11, 2006 (Filed as Exhibit 16.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed April 11, 2006 and incorporated herein by reference).
21*	Subsidiaries of TEPPCO Partners, L.P.

Exhibit Number	Description
23.1*	Consent of Deloitte & Touche LLP.
23.2*	Consent of KPMG LLP.
24*	Powers of Attorney.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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

TEPPCO Partners, L.P.

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

Date: February 28, 2007

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

Date: February 28, 2007

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

Signature	Title	Date
JERRY E. THOMPSON Jerry E. Thompson	President and Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC (Principal Executive Officer)	February 28, 2007
WILLIAM G. MANIAS William G. Manias	Vice President and Chief Financial Officer of Texas Eastern Products Pipeline Company, LLC (Principal Financial and Accounting Officer)	February 28, 2007
MICHAEL B. BRACY* Michael B. Bracy	Director of Texas Eastern Products Pipeline Company, LLC	February 28, 2007
RICHARD S. SNELL* Richard S. Snell	Director of Texas Eastern Products Pipeline Company, LLC	February 28, 2007
MURRAY H. HUTCHISON* Murray H. Hutchison	Chairman of the Board of Texas Eastern Products Pipeline Company, LLC	February 28, 2007

* Signed on behalf of the Registrant and each of these persons pursuant to Powers of Attorney filed as Exhibit 24:

By: /s/ WILLIAM G. MANIAS
(William G. Manias, Attorney-in-fact)

CONSOLIDATED FINANCIAL STATEMENTS
OF TEPPCO PARTNERS, L.P.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheet of TEPPCO Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2006, and the related statements of consolidated income and comprehensive income, consolidated cash flows and consolidated partners' capital for the year ended December 31, 2006. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements based on our audit.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of TEPPCO Partners, L.P. and subsidiaries as of December 31, 2006, and the results of their operations and their cash flows for the year ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2007, expressed an unqualified opinion on management's assessment of the effectiveness of the Partnership's internal control over financial reporting and an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

The Partnership changed its method of financial statement presentation related to purchases and sales of inventory with the same counterparty. This change is discussed in Note 3 to the consolidated financial statements.

/s/ Deloitte & Touche LLP

Houston, Texas
February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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

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

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

KPMG LLP

Houston, Texas
February 28, 2006, except for the effects of discontinued operations,
as discussed in Note 11, which is as of June 1, 2006

TEPPCO PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 70	$ 119
Accounts receivable, trade (net of allowance for doubtful accounts of $100 and $250)	852,816	803,373
Accounts receivable, related parties	11,788	5,207
Inventories	72,193	29,069
Other	29,843	61,361
Total current assets	966,710	899,129
Property, plant and equipment, at cost (net of accumulated depreciation and amortization of $509,889 and $474,332)	1,642,095	1,960,068
Equity investments	1,039,710	359,656
Intangible assets	185,410	376,908
Goodwill	15,506	16,944
Other assets	72,661	67,833
Total assets	$ 3,922,092	$ 3,680,538
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 855,306	$ 800,033
Accounts payable, related parties	34,461	11,836
Accrued interest	35,523	32,840
Other accrued taxes	14,482	16,532
Other	36,776	75,970
Total current liabilities	976,548	937,211
Senior notes	1,113,287	1,119,121
Other long-term debt	490,000	405,900
Deferred tax liability	652	—
Other liabilities and deferred credits	19,461	16,936
Other liabilities, related party	1,814	—
Commitments and contingencies		
Partners' capital:		
Accumulated other comprehensive income	426	11
General partner's interest	(85,655)	(61,487)
Limited partners' interests	1,405,559	1,262,846
Total partners' capital	1,320,330	1,201,370
Total liabilities and partners' capital	$ 3,922,092	$ 3,680,538

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

STATEMENTS OF CONSOLIDATED INCOME AND COMPREHENSIVE INCOME
(Dollars in thousands)

	For Year Ended December 31, 2006	2005	2004
Operating revenues:			
Sales of petroleum products	$ 9,080,516	$ 8,061,808	$ 5,426,832
Transportation – Refined products	152,552	144,552	148,166
Transportation – LPGs	89,315	96,297	87,050
Transportation – Crude oil	38,822	37,614	37,177
Transportation – NGLs	43,838	43,915	41,204
Gathering – Natural gas	123,933	152,797	140,122
Other	78,509	68,051	67,539
Total operating revenues	9,607,485	8,605,034	5,948,090
Costs and expenses:			
Purchases of petroleum products	8,967,062	7,986,438	5,367,027
Operating expense	203,015	185,777	191,893
Operating fuel and power	57,450	48,972	48,139
General and administrative	31,348	33,143	28,016
Depreciation and amortization	108,252	110,729	112,284
Taxes – other than income taxes	17,983	20,610	17,340
Gains on sales of assets	(7,404)	(668)	(1,053)
Total costs and expenses	9,377,706	8,385,001	5,763,646
Operating income	229,779	220,033	184,444
Other income (expense):			
Interest expense – net	(86,171)	(81,861)	(72,053)
Equity earnings	36,761	20,094	22,148
Interest income	2,077	687	467
Other income – net	888	448	853
Income before deferred income tax expense	183,334	159,401	135,859
Deferred income tax expense	652	—	—
Income from continuing operations	182,682	159,401	135,859
Income from discontinued operations	1,497	3,150	2,689
Gain on sale of discontinued operations	17,872	—	—
Discontinued operations	19,369	3,150	2,689
Net income	$ 202,051	$ 162,551	$ 138,548
Changes in fair values of interest rate cash flow hedges	(248)	—	—
Changes in fair values of crude oil cash flow hedges	730	11	—
Comprehensive income	$ 202,533	$ 162,562	$ 138,548

TEPPCO PARTNERS, L.P.

STATEMENTS OF CONSOLIDATED INCOME AND COMPREHENSIVE INCOME – (Continued)
(Dollars in thousands, except per Unit amounts)

	For Year Ended December 31,		
	2006	2005	2004
Net Income Allocation:			
Limited Partner Unitholders:			
Income from continuing operations	$ 130,483	$ 112,744	$ 96,667
Income from discontinued operations	13,835	2,228	1,913
Total Limited Partner Unitholders net income allocation	144,318	114,972	98,580
General Partner:			
Income from continuing operations	52,199	46,657	39,192
Income from discontinued operations	5,534	922	776
Total General Partner net income allocation	57,733	47,579	39,968
Total net income allocated	$ 202,051	$ 162,551	$ 138,548
Basic and diluted net income per Limited Partner Unit:			
Continuing operations	$ 1.77	$ 1.67	$ 1.53
Discontinued operations	0.19	0.04	0.03
Basic and diluted net income per Limited Partner Unit	$ 1.96	$ 1.71	$ 1.56
Weighted average Limited Partner Units outstanding	73,657	67,397	62,999

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For Year Ended December 31,		
	2006	2005	2004
Operating activities:			
Net income	$ 202,051	$ 162,551	$ 138,548
Adjustments to reconcile net income to cash provided by continuing operating activities:			
Income from discontinued operations	(19,369)	(3,150)	(2,689)
Deferred income tax expense	652	—	—
Depreciation and amortization	108,252	110,729	112,284
Earnings in equity investments	(36,761)	(20,094)	(22,148)
Distributions from equity investments	63,483	37,085	47,213
Gains on sales of assets	(7,404)	(668)	(1,053)
Non-cash portion of interest expense	1,676	1,624	(391)
Net effect of changes in operating accounts	(41,028)	(37,354)	(7,868)
Net cash provided by continuing operating activities	271,552	250,723	263,896
Net cash provided by discontinued operations	1,521	3,782	3,271
Net cash provided by operating activities	273,073	254,505	267,167
Investing activities:			
Proceeds from sales of assets	51,558	510	1,226
Acquisition of assets	(20,473)	(112,231)	(3,421)
Investment in Centennial Pipeline LLC	(2,500)	—	(1,500)
Investment in Mont Belvieu Storage Partners, L.P.	(4,767)	(4,233)	(21,358)
Investment in Jonah Gas Gathering Company	(121,035)	—	—
Cash paid for linefill on assets owned	(6,453)	(14,408)	(957)
Capital expenditures	(170,046)	(220,553)	(156,749)
Net cash used in continuing investing activities	(273,716)	(350,915)	(182,759)
Net cash used in discontinued investing activities	—	—	(7,398)
Net cash used in investing activities	(273,716)	(350,915)	(190,157)
Financing activities:			
Proceeds from revolving credit facility	924,125	657,757	324,200
Issuance of Limited Partner Units, net	195,060	278,806	—
Repayments on revolving credit facility	(840,025)	(604,857)	(181,200)
Debt issuance costs	—	(498)	—
Distributions paid	(278,566)	(251,101)	(233,057)
Net cash provided by (used in) financing activities	594	80,107	(90,057)
Net change in cash and cash equivalents	(49)	(16,303)	(13,047)
Cash and cash equivalents, January 1	119	16,422	29,469
Cash and cash equivalents, December 31	$ 70	$ 119	$ 16,422

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

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) Income	Total
Balance, December 31, 2003	62,998,554	$ (8,950)	$ 1,114,661	$ (2,902)	$ 1,102,809
Adjustments to issuance of Limited Partner Units, net	—	—	(99)	—	(99)
Net income on cash flow hedge	—	—	—	2,902	2,902
2004 net income allocation	—	39,968	98,580	—	138,548
2004 cash distributions	—	(66,899)	(166,158)	—	(233,057)
Balance, December 31, 2004	62,998,554	(35,881)	1,046,984	—	1,011,103
Issuance of Limited Partner Units, net Partner Units, net	6,965,000	—	278,806	—	278,806
Changes in fair values of crude oil cash flow hedges	—	—	—	11	11
2005 net income allocation	—	47,579	114,972	—	162,551
2005 cash distributions	—	(73,185)	(177,916)	—	(251,101)
Balance, December 31, 2005	69,963,554	(61,487)	1,262,846	11	1,201,370
Issuance of Limited Partner Units, net	5,750,000	—	195,060	—	195,060
Issuance of Limited Partner Units to General Partner	14,091,275	—	—	—	—
2006 net income allocation	—	57,733	144,318	—	202,051
2006 cash distributions	—	(81,901)	(196,665)	—	(278,566)
Changes in fair values of crude oil cash flow hedges	—	—	—	730	730
Changes in fair values of interest rate cash flow hedges	—	—	—	(248)	(248)
Adjustment to initially apply SFAS No. 158	—	—	—	(67)	(67)
Balance, December 31, 2006	89,804,829	$ (85,655)	$ 1,405,559	$ 426	$ 1,320,330

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. PARTNERSHIP ORGANIZATION

TEPPCO Partners, L.P. (the "Partnership") is a publicly traded Delaware limited partnership and our limited partner 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 were formed in March 1990, and we operate through TE Products Pipeline Company, Limited Partnership ("TE Products"), TCTM, L.P. ("TCTM") and TEPPCO Midstream Companies, L.P. ("TEPPCO Midstream"). Collectively, TE Products, TCTM and TEPPCO Midstream are referred to as the "Operating Partnerships." Texas Eastern Products Pipeline Company, LLC ("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 the Operating Partnerships and TEPPCO GP holds a 0.001% general partner interest.

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

At formation in 1990, we completed an initial public offering of 26,500,000 units representing Limited Partner Interests ("Limited Partner Units") at $10.00 per Limited Partner Unit ("Unit"). Through February 23, 2005, Duke Energy owned 2,500,000 Units that have not been listed for trading on the NYSE. On February 24, 2005, DFI entered into an LP Unit Purchase and Sale Agreement with Duke Energy and purchased these 2,500,000 Units for $104.0 million. As of December 31, 2006, none of these Units had been sold by DFI.

On December 8, 2006, at a special meeting of our unitholders, the Fourth Amended and Restated Agreement of Limited Partnership (the "New Partnership Agreement"), which amends and restates the Third Amended and Restated Agreement of Limited Partnership in effect prior to the special meeting (the "Previous Partnership Agreement") was approved and became effective. The New Partnership Agreement contains the following amendments to the Previous Partnership Agreement, among others:

- changes to certain provisions that relate to distributions and capital contributions, including the reduction in the General Partner's incentive distribution rights from 50% to 25% ("IDR Reduction Amendment"), elimination of the General Partner's requirement to make capital contributions to us to maintain a 2% capital account, and adjustment of our minimum quarterly distribution and target distribution levels for entity-level taxes;

- changes to various voting percentage requirements, in most cases from 66 $^{2}/_{3}$% of outstanding Units to a majority of outstanding Units;
- a reduction in the percentage of holders of outstanding Units necessary to constitute a quorum was reduced from 66 $^{2}/_{3}$% to a majority of the outstanding Units;
- removal of provisions requiring unitholder approval for specified actions with respect to the Operating Partnerships;
- changes to supplement and revise certain provisions that relate to conflicts of interest and fiduciary duties; and
- changes to provide for certain registration rights of the General Partner and its affiliates (including with respect to the Units issued in respect of the IDR Reduction Amendment, as described below), for the maintenance of the separateness of us from any other person or entity and other miscellaneous matters.

References in this Report to our "Partnership Agreement" are to our partnership agreement (including, as applicable, the Previous Partnership Agreement or the New Partnership Agreement), as in effect from time to time. By approval of the various proposals at the special meeting, and upon effectiveness of the New Partnership Agreement, an agreement was effectuated whereby we issued 14,091,275 Units on December 8, 2006 to our General Partner as consideration for the IDR Reduction Amendment. The number of Units issued to our General Partner was based upon a predetermined formula that, based on the distribution rate and the number of Units outstanding at the time of the issuance, resulted in our General Partner receiving cash distributions from the newly-issued Units and from its reduced maximum percentage interest in our quarterly distributions approximately equal to the cash distributions our General Partner would have received from its maximum percentage interest in our quarterly distributions without the IDR Reduction Amendment. Effective as of December 8, 2006, the General Partner distributed the newly issued Units to its member, which in turn caused them to be distributed to other affiliates of EPCO.

At December 31, 2006, 2005 and 2004, we had outstanding 89,804,829, 69,963,554 and 62,998,554 Units, respectively.

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Business Segments

We operate and report in three business segments: transportation, marketing and storage of refined products, liquefied petroleum gases ("LPGs") and petrochemicals ("Downstream Segment"); gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals ("Upstream Segment"); and gathering of natural gas, fractionation of natural gas liquids ("NGLs") and transportation of NGLs ("Midstream Segment"). Our reportable segments offer different products and services and are managed separately because each requires different business strategies (see Note 15).

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

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of the outstanding balance. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. Our procedure for recording an allowance for doubtful accounts is based on (i) our historical experience, (ii) the financial stability of our customers and (iii) the levels of credit granted to customers. In addition, we may also increase the allowance account in response to specific identification of customers involved in bankruptcy proceedings and those experiencing other financial difficulties. We routinely review our estimates in this area to ensure that we have recorded sufficient reserves to cover potential losses. The following table presents the activity of our allowance for doubtful accounts for the years ended December 31, 2006, 2005 and 2004:

	For Year Ended December 31,		
	2006	2005	2004
Balance at beginning of period	$ 250	$ 112	$ 4,700
Charges to expense	64	829	536
Deductions and other	(214)	(691)	(5,124)
Balance at end of period	$ 100	$ 250	$ 112

Asset Retirement Obligations

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from its acquisition, construction, development and/or normal operation. We record a liability for AROs when incurred and capitalize an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over its useful life. We will either settle our ARO obligations at the recorded amount or incur a gain or loss upon settlement.

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

We have determined that we are obligated by contractual or regulatory requirements to remove certain facilities or perform other remediation upon retirement of our assets. However, we are not able to reasonably determine the fair value of the AROs for our trunk, interstate and gathering pipelines and our surface facilities, since future dismantlement and removal dates are indeterminate. During 2006, we recorded $0.6 million of expense, included in depreciation and amortization expense, related to conditional AROs related to the retirement of the 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. Additionally, we have recorded a $1.2 million liability, which represents the fair values of these conditional AROs. During 2006, we assigned probabilities for settlement dates and settlement methods for use in an expected present value measurement of fair value and recorded conditional AROs.

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

We will record AROs in the period in which more information becomes available for us to reasonably estimate the settlement dates of the retirement obligations. The adoption of Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations* and Financial Accounting Standards Board ("FASB") Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143*, ("FIN 47") did not have a material effect on our financial position, results of operations or cash flows.

Basis of Presentation and Principles of Consolidation

The financial statements include our accounts on a consolidated basis. We have eliminated all significant intercompany items in consolidation. We have reclassified certain amounts from prior periods to conform to the current presentation. Our results for the years ended December 31, 2006, 2005 and 2004 reflect the operations and activities of Jonah Gas Gathering Company's ("Jonah") Pioneer plant as discontinued operations.

Cash and Cash Equivalents

Cash equivalents are defined as all highly marketable securities with maturities of three months or less when purchased. The carrying value of cash equivalents approximate fair value because of the short term nature of these investments. Our Statements of Consolidated Cash Flows are prepared using the indirect method.

Capitalization of Interest

We capitalize interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average rate used to capitalize interest on borrowed funds was 6.27%, 5.73% and 5.74% for the years ended December 31, 2006, 2005 and 2004, respectively. During the years ended December 31, 2006, 2005 and 2004, the amount of interest capitalized was $10.7 million, $6.8 million and $4.2 million, respectively.

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Our management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our legal counsel evaluates the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss if determinable and material, is disclosed.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

Dollar Amounts

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 of dollars.

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.

The following table presents the activity of our environmental reserve for the years ended December 31, 2006, 2005 and 2004:

	For Year Ended December 31,		
	2006	2005	2004
Balance at beginning of period	$ 2,447	$ 5,037	$ 7,639
Charges to expense	1,887	2,530	5,178
Deductions and other	(2,532)	(5,120)	(7,780)
Balance at end of period	$ 1,802	$ 2,447	$ 5,037

Estimates

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

Fair Value of Current Assets and Current Liabilities

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

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired and is presented on the consolidated balance sheets net of accumulated amortization. Our goodwill amounts are assessed for impairment (i) on an annual basis during the fourth quarter of each year or (ii) on an interim basis when impairment indicators are present. If such indicators are present (e.g., loss of a significant customer, economic obsolescence of plant assets, etc.), the fair value of the reporting unit to which the goodwill is assigned will be calculated and compared to its book value.

If the fair value of the reporting unit exceeds its book value, the goodwill amount is not considered to be impaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value, a charge to earnings is recorded to adjust the carrying value of the goodwill to its implied fair value. We have not recognized any impairment losses related to our goodwill for any of the periods presented (see Note 12 for a further discussion of our goodwill).

Income Taxes

We are a limited partnership. As such, we are not a taxable entity for federal and state income tax purposes and do not directly pay federal and state income tax. Our taxable income or loss, which may vary substantially from the net income or net loss we report in our statements of consolidated income, is includable in the federal and state income tax returns of each unitholder. Accordingly, except as noted below, no recognition has been given to federal and state income taxes for our operations. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each unitholders' tax attributes in the Partnership.

Texas Margin Tax

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

The Texas Margin Tax is assessed at 1% of Texas-sourced taxable margin measured by the ratio of gross receipts from business done in Texas to gross receipts from business done everywhere. The taxable margin is computed as the lesser of (i) 70% of total revenue or (ii) total revenues less (a) cost of goods sold or (b) compensation. The deferred tax liability shown on our consolidated balance sheet reflects the net tax effect of temporary differences related to items such as property, plant and equipment; therefore, the deferred tax liability is classified as noncurrent. The Texas Margin Tax is calculated, paid and filed at an affiliated unitary group level. Generally, an affiliated group is made up of one or more entities in which a controlling interest of at least 80% is owned by a common owner or owners. Generally, a business is unitary if it is characterized by a sharing or exchange of value between members of the group, and a synergy and mutual benefit all of the members of the group achieved by working together. We have calculated and recorded an estimated deferred tax liability of approximately $0.7 million associated with the Texas Margin Tax. The non-cash offsetting charge is shown on our statements of consolidated income as deferred income tax expense for the year ended December 31, 2006.

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

Intangible Assets and Excess Investments

Intangible assets on the consolidated balance sheets consist primarily of gathering contracts assumed in the acquisition of Val Verde Gathering System (“Val Verde”) on June 30, 2002, a fractionation agreement and other intangible assets (see Note 12). Included in equity investments on the consolidated balance sheets are excess investments in Centennial Pipeline LLC (“Centennial”), Seaway Crude Pipeline Company (“Seaway”) and Jonah.

In connection with the acquisition of Val Verde, we assumed fixed-term contracts with customers that gather coal bed methane from the San Juan Basin in New Mexico and Colorado. The value assigned to these intangible assets relates to contracts with customers that are for a fixed term. These intangible assets are amortized on a unit-of-production basis, based upon the actual throughput of the system over the expected total throughput for the lives of the contracts. Revisions to the unit-of-production estimates may occur as additional production information is made available to us (see Note 12).

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

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

In connection with the formation of Centennial, we recorded excess investment, the majority of which is amortized on a unit-of-production basis over a period of 10 years. In connection with the acquisition of our interest in Seaway, we recorded excess investment, which is amortized on a straight-line basis over a period of 39 years. In connection with the formation of our Jonah joint venture and the construction of its expansion, we recorded excess investment (see Note 12).

Inventories

Inventories consist primarily of petroleum products, which are valued at the lower of cost (weighted average cost method) or market. Our Downstream Segment acquires and disposes of various products under exchange agreements. Receivables and payables arising from these transactions are usually satisfied with products rather than cash. The net balances of exchange receivables and payables are valued at weighted average cost and included in inventories. Inventories of materials and supplies, used for ongoing replacements and expansions, are carried at cost.

Natural Gas Imbalances

Gas imbalances occur when gas producers (customers) deliver more or less actual natural gas gathering volumes to our gathering systems than they originally nominated. Actual deliveries are different from nominated volumes due to fluctuations in gas production at the wellhead. To the extent that these shipper imbalances are not cashed out, Val Verde records a payable to shippers who supply more natural gas gathering volumes than nominated, and receivable from the shippers who nominate more natural gas gathering volumes than supplied. To the extent pipeline imbalances are not cashed out, Val Verde records a receivable from connecting pipeline transporters when total volumes delivered exceed the total of shipper’s nominations and records a payable to connecting pipeline transporters when the total shippers’ nominations exceed volumes delivered. We record natural gas imbalances using a mark-to-market approach.

Net Income Per Unit

Basic net income per Unit is computed by dividing net income, after deduction of the General Partner's interest, by the weighted average number of Units outstanding (a total of 73.7 million Units, 67.4 million Units and 63.0 million Units for the years ended December 31, 2006, 2005 and 2004, respectively). The General Partner's percentage interest in our net income is based on its percentage of cash distributions from Available Cash for each year (see Note 14). The General Partner was allocated $57.7 million (representing 28.57%) of net income for the year ended December 31, 2006, $47.6 million (representing 29.27%) of net income for the year ended December 31, 2005, and $40.0 million (representing 28.85%) of net income for the year ended December 31, 2004.

The General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase, in accordance with our Partnership Agreement. On December 8, 2006, our Partnership Agreement was amended (see Note 1), and our General Partner's maximum percentage interest in our quarterly distributions was reduced from 50% to 25%. We issued 14.1 million Units on December 8, 2006 to our General Partner as consideration for the IDR Reduction Amendment. The number of Units issued to our General Partner was based upon a predetermined formula that, based on the distribution rate and the number of Units outstanding at the time of the issuance, resulted in our General Partner receiving cash distributions from the newly-issued Units and from its reduced maximum percentage interest in our quarterly distributions approximately equal to the cash distributions our General Partner would have received from its maximum percentage interest in our quarterly distributions without the IDR Reduction Amendment.

Diluted net income per Unit is similar to the computation of basic net income per Unit discussed above, except that the denominator is increased to include the dilutive effect of outstanding Unit options by application of the treasury stock method. For the years ended December 31, 2006, 2005 and 2004, diluted net income per Unit equaled basic net income per Unit as there were no dilutive instruments outstanding.

Property, Plant and Equipment

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

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

Revenue Recognition

Our Downstream Segment revenues are earned from transportation, marketing and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. Transportation revenues are recognized as products are delivered to customers. Storage revenues are recognized upon receipt of products into storage and upon performance of storage services. Terminaling revenues are recognized as products are out-loaded. Revenues from the sale of product inventory are recognized when the products are sold. Our 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 sales at the Aberdeen truck rack to independent wholesalers and retailers of refined products. These purchases and sales are generally contracted to occur on the same day.

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

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

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

Unit Option Plan and Unit Purchase Plan

At a special meeting of our unitholders on December 8, 2006, our unitholders approved the EPCO, Inc. 2006 TPP Long-Term Incentive Plan, which provides for awards of our Units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under this plan may be granted in the form of restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. Additionally, our unitholders approved the EPCO, Inc. TPP Employee Unit Purchase Plan, which provides for discounted purchases of our Units by employees of EPCO and its affiliates. Generally, any employee who (1) has been employed by EPCO or any of its designated affiliates for three consecutive months, (2) is a regular, active and full time employee and (3) is scheduled to work at least 30 hours per week is eligible to participate in this plan, provided that employees covered by collective bargaining agreements (unless otherwise specified therein) and 5% owners of us, EPCO or any affiliate are not eligible to participate (see Note 4).

Use of Derivatives

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

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

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

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

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

NOTE 3. RECENT ACCOUNTING DEVELOPMENTS

In December 2004, the FASB issued SFAS No. 123(R) (revised 2004), *Share-Based Payment*. SFAS 123(R) is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*, as amended by SFAS No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure* and supersedes Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees*. SFAS 123(R) requires that the cost resulting from all share-based payment transactions be recognized in the financial statements at fair value. SFAS 123(R) became effective for public companies for annual periods beginning after June 15, 2005. Accordingly, we adopted SFAS 123(R) in the first quarter of 2006. We adopted SFAS 123(R) under the modified prospective transition method. We have determined that our 1999 Phantom Unit Retention Plan and our 2005 Phantom Unit Plan are liability awards under the provisions of SFAS 123(R). No additional compensation expense has been recorded in connection with the adoption of SFAS 123(R) as we have historically recorded the associated liabilities at fair value. The adoption of SFAS 123(R) did not have a material effect on our financial position, results of operations or cash flows.

In June 2005, the Emerging Issues Task Force ("EITF") reached consensus in EITF 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights*, to provide guidance on how general partners in a limited partnership should determine whether they control a limited partnership and therefore should consolidate it. The EITF agreed that the presumption of general partner control would be overcome only when the limited partners have either of two types of rights. The first type, referred to as "kick-out rights," is the right to dissolve or liquidate the partnership or otherwise remove the general partner without cause. The second type, referred to as "participating rights," is the right to effectively participate in significant decisions made in the ordinary course of the partnership's business. The kick-out rights and the participating rights must be substantive in order to overcome the presumption of general partner control. The consensus is effective for general partners of all new limited partnerships formed and for existing limited partnerships for which the partnership agreements are modified subsequent to the date of FASB ratification (June 29, 2005). For existing limited partnerships that have not been modified, the guidance in EITF 04-5 is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005. Although this EITF did not directly impact us, it did impact our General Partner. The adoption of EITF 04-5 on January 1, 2006 by our General Partner resulted in the consolidation of our statements of consolidated income and balance sheet into its consolidated financial statements.

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

In September 2005, the EITF reached consensus in EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, to define when a purchase and a sale of inventory with the same party that operates in the same line of business should be considered a single nonmonetary transaction subject to APB Opinion No. 29, *Accounting for Nonmonetary Transactions*. Two or more inventory transactions with the same party should be combined if they are entered into in contemplation of one another. The EITF also requires entities to account for exchanges of inventory in the same line of business at fair value or recorded amounts based on inventory classification. The guidance in EITF 04-13 is effective for new inventory arrangements entered into in reporting periods beginning after March 15, 2006. We adopted EITF 04-13 on April 1, 2006, which resulted in crude oil inventory purchases and sales under buy/sell transactions, which were previously recorded as gross purchases and sales, to be treated as inventory exchanges in our statements of consolidated income. EITF 04-13 reduced gross revenues and purchases, but did not have a material effect on our financial position, results of operations or cash flows. The treatment of buy/sell transactions under EITF 04-13 reduced the relative amount of revenues and purchases of petroleum products on our statements of consolidated income by approximately $1,127.6 million for the period from April 1, 2006 through December 31, 2006. The revenues and purchases of petroleum products associated with buy/sell transactions that are reported on a gross basis in our statements of consolidated income for the period from January 1, 2006 through March 31, 2006, and for the years ended December 31, 2005 and 2004, are approximately $275.4 million, $1,405.7 million and $496.1 million, respectively.

In June 2006, the EITF reached consensus in EITF 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)*. The accounting guidance permits companies to elect to present on either a gross or net basis sales and other taxes that are imposed on and concurrent with individual revenue-producing transactions between a seller and a customer. The gross basis includes the taxes in revenues and costs; the net basis excludes the taxes from revenues. The accounting guidance does not apply to tax systems that are based on gross receipts or total revenues. EITF 06-3 requires companies to disclose their policy for presenting the taxes and disclose any amounts presented on a gross basis if those amounts are significant. The guidance in EITF 06-3 is effective January 1, 2007. As a matter of policy, we report such taxes on a net basis. We believe that adoption of EITF 06-3 will not have a material effect on our financial position, results of operations or cash flows.

In June 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, an Interpretation of SFAS 109, *Accounting for Income Taxes* ("FIN 48"). FIN 48 provides that the tax effects of an uncertain tax position should be recognized in a company's financial statements if the position taken by the entity is more likely than not sustainable if it were to be examined by an appropriate taxing authority, based on technical merit. After determining if a tax position meets such criteria, the amount of benefit to be recognized should be the largest amount of benefit that has more than a 50% chance of being realized upon settlement. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, and we were required to adopt FIN 48 as of January 1, 2007. The adoption of FIN 48 did not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS 157 applies only to fair-value measurements that are already required or permitted by other accounting standards and is expected to increase the consistency of those measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies will be required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop the measurements, and the effect of certain of the measurements on earnings (or changes in net assets) for the period. SFAS 157 is effective for fiscal years beginning after December 15, 2007, and we are required to adopt SFAS 157 as of January 1, 2008. We believe that the adoption of SFAS 157 will not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* ("SAB 108"). SAB 108 addresses how the effects of prior-year uncorrected misstatements should be considered when quantifying misstatements in current-year financial statements. The SAB requires registrants to quantify misstatements using both balance-sheet and income-statement approaches and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is determined to be material, SAB 108 allows registrants to record that effect as a cumulative-effect adjustment to beginning-of-year retained earnings. The requirements are effective for annual financial statements covering the first fiscal year ending after November 15, 2006. Additionally, the nature and amount of each individual error being corrected through the cumulative-effect adjustment, when and how each error arose, and the fact that the errors had previously been considered immaterial is required to be disclosed. We are required to adopt SAB 108 for our current fiscal year ending December 31, 2006. The adoption of SAB 108 did not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*. SFAS 158 requires an employer to recognize the over-funded or under-funded status of its defined benefit pension and other postretirement plans as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. In addition, SFAS 158 eliminates the use of a measurement date that is different than the date of the employer's year-end financial statements. SFAS 158 requires an employer to disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation. The requirement to recognize the funded status and to provide the required disclosures is effective for fiscal years ending after December 15, 2006. Accordingly, we adopted SFAS 158 in the fourth quarter 2006. The adoption of SFAS 158 did not have a material effect on our financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115*. SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between the different measurement attributes the company elects for similar types of assets and liabilities. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact of the adoption of SFAS 159 on our financial statements. We do not believe the adoption of SFAS 159 will have a material effect on our financial position, results of operations or cash flows.

NOTE 4. ACCOUNTING FOR EQUITY AWARDS

1994 Long Term Incentive Plan

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

According to the plan provisions, when our calendar year earnings per Unit (exclusive of certain special items) exceeded a stated threshold, each participant received a credit to their respective Performance Unit account equal to the earnings per Unit excess multiplied by the number of Performance Units awarded. The balance in the Performance Unit account could have been used to offset the cost of exercising Unit options granted in connection with the Performance Units or could have been withdrawn two years after the underlying options expire, usually 10 years from the date of grant. Any unused balance previously credited was forfeited upon termination. We accrued compensation expense for the Performance Units awarded annually based upon the terms of the plan discussed above. Under the agreement for such Unit options, the options became exercisable in equal installments over periods of one, two, and three years from the date of the grant.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

At December 31, 2006, all options have been fully exercised. We have not granted options for any periods presented, and we have no accrued liability balances remaining for Performance Unit accounts. The 1994 LTIP was terminated effective as of June 19, 2006.

1999 and 2002 Phantom Unit Retention Plans

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

Under the agreement for the phantom units, each participant vests the number of phantom units initially granted under his or her award according to the terms agreed upon at the grant date. Each participant is required to redeem their phantom units as they vest. Each participant is also entitled to quarterly cash distributions equal to the product of the number of phantom units outstanding for the participant and the amount of the cash distribution that we paid per Unit to our unitholders.

We accrue compensation expense annually based upon the terms of the 1999 Plan and 2002 PURP discussed above. Due to the change in ownership of our General Partner on February 24, 2005 (see Note 1), all phantom units outstanding at February 24, 2005 under both the 1999 Plan and the 2002 PURP fully vested and were redeemed by participants in 2005. As such, there were no outstanding phantom units under either the 1999 Plan or the 2002 PURP at December 31, 2005. During 2006, a total of 44,600 phantom units were granted under the 1999 Plan and remain outstanding at December 31, 2006. At December 31, 2006, we had an accrued liability balance of $0.8 million for compensation related to the 1999 Plan. No amounts were outstanding and no liabilities remained at December 31, 2006 for the 2002 PURP.

2000 Long Term Incentive Plan

Effective January 1, 2000, the General Partner established the Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan ("2000 LTIP") to provide key employees incentives to achieve improvements in our financial performance. Generally, upon the close of a three-year performance period, if the participant is then still an employee of EPCO, the participant will receive a cash payment in an amount equal to (1) the applicable performance percentage specified in the award multiplied by (2) the number of phantom units granted under the award multiplied by (3) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. Generally, a participant's performance percentage is based upon the improvement of our Economic Value Added (as defined below) during a three-year performance period over the Economic Value Added during the three-year period immediately preceding the performance period. If a participant incurs a separation from service during the performance period due to death, disability or retirement (as such terms are defined in the 2000 LTIP), the participant will be entitled to receive a cash payment in an amount equal to the amount computed as described above multiplied by a fraction, the numerator of which is the number of days that have elapsed during the performance period prior to the participant's separation from service and the denominator of which is the number of days in the performance period.

At December 31, 2006, phantom units outstanding under the 2000 LTIP were 11,300 and 8,400 for awards granted for the years ended December 31, 2006 and 2005, respectively. At December 31, 2005, there were 23,400 phantom units outstanding for awards granted for the plan year ended December 31, 2005. All phantom units for awards granted under the 2003 and 2004 plan years became fully vested and were paid out to participants in 2005, in accordance with plan provisions as a result of the change in ownership of our General Partner on February 24, 2005.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Economic Value Added means our average annual EBITDA for the performance period minus the product of our average asset base and our cost of capital for the performance period. EBITDA means our earnings before net interest expense, other income – net, depreciation and amortization and our proportional interest in EBITDA of our joint ventures as presented in our consolidated financial statements prepared in accordance with generally accepted accounting principles, except that at his discretion the Chief Executive Officer ("CEO") of the General Partner may exclude gains or losses from extraordinary, unusual or non-recurring items. Average asset base means the quarterly average, during the performance period, of our gross value of property, plant and equipment, plus products and crude oil operating oil supply and the gross value of intangibles and equity investments. Our cost of capital is approved by our CEO at the date of award grant.

In addition to the payment described above, during the performance period, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under this award. We accrue compensation expense annually based upon the terms of the 2000 LTIP discussed above. At December 31, 2006 and 2005, we had an accrued liability balance of $0.6 million and $0.7 million, respectively, for compensation related to the 2000 LTIP.

2005 Phantom Unit Plan

Effective January 1, 2005, the General Partner adopted the Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan ("2005 Phantom Unit Plan") to provide key employees incentives to achieve improvements in our financial performance. Generally, upon the close of a three-year performance period, if the participant is then still an employee of EPCO, the participant will receive a cash payment in an amount equal to (1) the grantee's vested percentage multiplied by (2) the number of phantom units granted under the award multiplied by (3) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. Generally, a participant's vested percentage is based upon the improvement of our EBITDA (as defined below) during a three-year performance period over the target EBITDA as defined at the beginning of each year during the three-year performance period. EBITDA means our earnings before minority interest, net interest expense, other income – net, income taxes, depreciation and amortization and our proportional interest in EBITDA of our joint ventures as presented in our consolidated financial statements prepared in accordance with generally accepted accounting principles, except that at his discretion, our CEO may exclude gains or losses from extraordinary, unusual or non-recurring items. At December 31, 2006, phantom units outstanding for awards granted for the years ended December 31, 2006 and 2005, were 44,200 and 44,000, respectively. At December 31, 2005, phantom units outstanding for awards granted for the plan year ended December 31, 2005, were 53,600.

In addition to the payment described above, during the performance period, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under this award. We accrue compensation expense annually based upon the terms of the 2005 Phantom Unit Plan discussed above. At December 31, 2006 and 2005, we had an accrued liability balance of $1.6 million and $0.7 million, respectively, for compensation related to the 2005 Phantom Unit Plan.

EPCO, Inc. 2006 TPP Long-Term Incentive Plan

At a special meeting of our unitholders on December 8, 2006, our unitholders approved the EPCO, Inc. 2006 TPP Long-Term Incentive Plan ("2006 LTIP"), which provides for awards of our Units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 2006 LTIP may be granted in the form of restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. The exercise price of unit options or unit appreciation rights awarded to participants will be determined by the Audit and Conflicts Committee of the board of directors of our General Partner ("AC

Committee") (at its discretion) at the date of grant and may be no less than the fair market value of the option award as of the date of grant. The 2006 LTIP will be administered by the AC Committee. 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. As of December 31, 2006, no awards had been granted under the 2006 LTIP. We will reimburse EPCO for the costs allocable to any future Incentive Plan awards made to employees who work in our business.

The 2006 LTIP may be amended or terminated at any time by the board of directors of EPCO, which is the indirect parent company of our General Partner, or the AC Committee; however, any material amendment, such as a material increase in the number of Units available under the plan or a change in the types of awards available under the plan, would require the approval of at least 50% of our unitholders. The AC Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the 2006 LTIP in specified circumstances. 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 AC Committee.

EPCO, Inc. TPP Employee Unit Purchase Plan

At a special meeting of our unitholders on December 8, 2006, our unitholders approved the EPCO, Inc. TPP Employee Unit Purchase Plan (the "Unit Purchase Plan"), which provides for discounted purchases of our Units by employees of EPCO and its affiliates. Generally, any employee who (1) has been employed by EPCO or any of its designated affiliates for three consecutive months, (2) is a regular, active and full time employee and (3) is scheduled to work at least 30 hours per week is eligible to participate in the Unit Purchase Plan, provided that employees covered by collective bargaining agreements (unless otherwise specified therein) and 5% owners of us, EPCO or any affiliate are not eligible to participate.

A maximum of 1,000,000 units may be delivered under the Unit Purchase Plan (subject to adjustment as provided in the plan). Units to be delivered under the plan may be acquired by the custodian of the plan in the open market or directly from us, EPCO, any of EPCO's affiliates or any other person; however, it is generally intended that Units are to be acquired from us. Eligible employees may elect to have a designated whole percentage (ranging from 1% to 10%) of their eligible compensation for each pay period withheld for the purchase of Units under the plan. EPCO and its affiliated employers will periodically remit to the custodian the withheld amounts, together with an additional amount by which EPCO will bear approximately 10% of the cost of the Units for the benefit of the participants. Unit purchases will be made following three month purchase periods over which the withheld amounts are to be accumulated. We will reimburse EPCO for all such costs allocated to employees who work in our business.

The plan will be administered by a committee appointed by the Chairman or Vice Chairman of EPCO. The Unit Purchase Plan may be amended or terminated at any time by the board of directors of EPCO, or the Chairman of the Board or Vice Chairman of the Board of EPCO; however, any material amendment, such as a material increase in the number of Units available under the plan or an increase in the employee discount amount, would also require the approval of at least 50% of our unitholders. 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 December 31, 2006, no purchase period has begun and no Units had been purchased under this plan.

NOTE 5. EMPLOYEE BENEFIT PLANS

Retirement Plans

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

On May 27, 2005, the TEPPCO RCBP and the TEPPCO SBP were amended. Effective May 31, 2005, participation in the TEPPCO RCBP was frozen, and no new participants were eligible to be covered by the plan after that date. Effective June 1, 2005, EPCO adopted the TEPPCO RCBP and the TEPPCO SBP for the benefit of its employees providing services to us. Effective December 31, 2005, all plan benefits accrued were frozen, participants received no additional pay credits after that date, and all plan participants were 100% vested regardless of their years of service. The TEPPCO RCBP plan was terminated effective December 31, 2005, and plan participants 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 IRS providing IRS approval of the plan termination. For those plan participants who elected to receive an annuity, we will purchase an annuity contract from an insurance company in which the plan participant owns the annuity, absolving us of any future obligation to the participant. Participants in the TEPPCO SBP received pay credits through November 30, 2005, and received lump sum benefit payments in December 2005. Both the TEPPCO RCBP and TEPPCO SBP benefit payments are discussed below.

In June 2005, we recorded a curtailment charge of $0.1 million in accordance with SFAS No. 88, *Employers’ Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, as a result of the TEPPCO RCBP and TEPPCO SBP amendments. As of May 31, 2005, the following assumptions were changed for purposes of determining the net periodic benefit costs for the remainder of 2005: the discount rate, the long-term rate of return on plan assets, and the assumed mortality table. The discount rate was decreased from 5.75% to 5.00% to reflect rates of returns on bonds currently available to settle the liability. The expected long-term rate of return on plan assets was changed from 8% to 2% due to the movement of plan funds from equity investments into short-term money market funds. The mortality table was changed to reflect overall improvements in mortality experienced by the general population. The curtailment charge arose due to the accelerated recognition of the unrecognized prior service costs. We recorded additional settlement charges of approximately $0.2 million in the fourth quarter of 2005 relating to the TEPPCO SBP. We recorded additional settlement charges of approximately $3.5 million during the fourth quarter of 2006 relating to the TEPPCO RCBP for any existing unrecognized losses upon the plan termination and final distribution of the assets to the plan participants. At December 31, 2006, $1.3 million of the TEPPCO RCBP plan assets had not been distributed to plan participants.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The components of net pension benefits costs for the TEPPCO RCBP and the TEPPCO SBP for the years ended December 31, 2006, 2005 and 2004, were as follows:

	For Year Ended December 31,		
	2006	2005	2004
Service cost benefit earned during the year	$ —	$ 4,393	$ 3,653
Interest cost on projected benefit obligation	891	934	719
Expected return on plan assets	(412)	(671)	(878)
Amortization of prior service cost	—	5	7
Recognized net actuarial loss	135	129	57
SFAS 88 curtailment charge	—	50	—
SFAS 88 settlement charge	3,545	194	—
Net pension benefits costs	$ 4,159	$ 5,034	$ 3,558

Other Postretirement Benefits

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

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

The components of net postretirement benefits cost for the TEPPCO OPB for the years ended December 31, 2006, 2005 and 2004, were as follows:

	For Year Ended December 31,		
	2006	2005	2004
Service cost benefit earned during the year	$ —	$ 81	$ 165
Interest cost on accumulated postretirement benefit obligation	—	69	153
Amortization of prior service cost	—	53	126
Recognized net actuarial loss	—	4	1
Curtailment credit	—	(1,676)	—
Settlement credit	—	(4)	—
Net postretirement benefits costs	$ —	$ (1,473)	$ 445

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

The weighted average assumptions used to determine benefit obligations for the retirement plans and other postretirement benefit plans at December 31, 2006 and 2005, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
Discount rate	4.73%	4.59%	—	5.75%
Increase in compensation levels	—	—	—	—

The weighted average assumptions used to determine net periodic benefit cost for the retirement plans and other postretirement benefit plans for the years ended December 31, 2006 and 2005, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
Discount rate (1)	4.59%	5.75%/5.00%	—	5.75%/5.00%
Increase in compensation levels	—	5.00%	—	—
Expected long-term rate of return on plan assets (2)	2.00%	8.00%/2.00%	—	—

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table sets forth our pension and other postretirement benefits changes in benefit obligation, fair value of plan assets and funded status as of December 31, 2006 and 2005:

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
Change in benefit obligation				
Benefit obligation at beginning of year	$ 22,111	$ 15,940	$ —	$ 2,964
Service cost	—	4,393	—	81
Interest cost	891	934	—	70
Actuarial loss	152	2,740	—	76
Retiree contributions	—	—	—	64
Benefits paid	(22,677)	(910)	—	(80)
Impact of curtailment	—	(986)	—	(3,575)
Settlement	—	—	—	400
Benefit obligation at end of year	$ 477	$ 22,111	$ —	$ —
Change in plan assets				
Fair value of plan assets at beginning of year	$ 23,104	$ 14,969	$ —	$ —
Actual return on plan assets	884	20	—	—
Retiree contributions	—	—	—	64
Employer contributions	—	9,025	—	16
Benefits paid	(22,677)	(910)	—	(80)
Fair value of plan assets at end of year	$ 1,311	$ 23,104	$ —	$ —
Funded status	$ 834	$ 993	$ —	$ —
Amount Recognized in the Balance Sheet:				
Noncurrent assets	$ 834	$ —	$ —	$ —
Net pension asset at end of year	$ 834	$ —	$ —	$ —
Amount Recognized in Accumulated Other Comprehensive Income:				
Unrecognized actuarial loss (1)	$ 67	$ —	$ —	$ —

(1) This amount will be amortized out of accumulated other comprehensive income into net periodic benefit cost in 2007.

The following table illustrates the incremental effect of applying SFAS No. 158 on individual line items in the consolidated balance sheet as of December 31, 2006:

	December 31, 2006		
	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
Prepaid pension cost (included in other current assets)	$ 901	$(901)	$ —
Other assets	71,827	834	72,661
Total assets	3,922,159	(67)	3,922,092
Accumulated other comprehensive income	493	(67)	426
Total partners' capital	1,320,397	(67)	1,320,330
Total liabilities and partners' capital	3,922,159	(67)	3,922,092

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

	Pension Benefits	Other Postretirement Benefits
2007	$477	$ —

Plan Assets

At December 31, 2006 and 2005, all plan assets for the retirement plans and other postretirement benefit plans were invested in money market securities. We do not expect to make further contributions to our retirement plans and other postretirement benefit plans in 2007.

Other Plans

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

EPCO maintains a 401(k) plan for the benefit of employees providing services to us, and we will continue to reimburse EPCO for the cost of maintaining this plan in accordance with the ASA.

NOTE 6. FINANCIAL INSTRUMENTS – INTEREST RATE SWAPS

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

In October 2001, TE Products entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its fixed rate 7.51% Senior Notes due 2028. We designated this swap agreement as a fair value hedge. The swap agreement has a notional amount of $210.0 million and matures in January 2028 to match the principal and maturity of the TE Products Senior Notes. Under the swap agreement, TE Products pays a floating rate of interest based on a three-month U.S. Dollar LIBOR rate, plus a spread of 147 basis points, and receives a fixed rate of interest of 7.51%. During the years ended December 31, 2006, 2005 and 2004, we recognized reductions in interest expense of $1.9 million, $5.6 million and $9.6 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. During the years ended December 31, 2006, 2005 and 2004, we reviewed the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized. The fair values of this interest rate swap were liabilities of approximately $2.6 million and $0.9 million at December 31, 2006 and 2005, respectively.

During 2002, we entered into interest rate swap agreements, designated as fair value hedges, to hedge our exposure to changes in the fair value of our fixed rate 7.625% Senior Notes due 2012. The swap agreements had a combined notional amount of $500.0 million and matured in 2012 to match the principal and maturity of the Senior Notes. Under the swap agreements, we paid a floating rate of interest based on a U.S. Dollar LIBOR rate, plus a spread, and received a fixed rate of interest of 7.625%. These swap agreements were later terminated in 2002 resulting in gains of $44.9 million. The gains realized from the swap terminations have been deferred as adjustments to the carrying value of the Senior Notes and are being amortized using the effective interest method as reductions to future interest expense over the remaining term of the Senior Notes. At December 31, 2006, the unamortized balance of the deferred gains was $28.0 million. In the event of early extinguishment of the Senior Notes, any remaining unamortized gains would be recognized in the statement of consolidated income at the time of extinguishment.

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

On January 20, 2006, we entered into interest rate swap agreements with a total notional amount of $200.0 million to hedge our exposure to increases in the benchmark interest rate underlying our variable rate revolving credit facility. These interest rate swaps mature in January 2008. Under the swap agreements, we pay a fixed rate of interest ranging from 4.67% to 4.695% and receive a floating rate based on a three-month U.S. Dollar LIBOR rate. In the third quarter of 2006, these swaps were designated as cash flow hedges. For the period from January 20, 2006 through the date these swaps were designated as cash flow hedges, changes in the fair value of the swaps were recognized in earnings, which resulted in a $2.2 million reduction to interest expense. While these interest rate swaps remain in effect, future changes in the fair value of the cash flow hedges, to the extent the swaps are effective, will be recognized in other comprehensive income until the hedged interest costs are recognized in earnings. At December 31, 2006, the fair value of these interest rate swaps was $1.1 million.

During October 2006, we executed a series of treasury rate lock agreements that extend through June 2007 for a notional amount totaling $200.0 million. These agreements, which are derivative instruments, have been designated as cash flow hedges to offset our exposure to increases in the underlying U.S. Treasury benchmark rate that is expected to be used to establish the fixed interest rate for debt that we expect to incur in 2007. The weighted average rate under the treasury lock agreements was approximately 4.7%. The actual coupon rate of the expected debt issuance will be comprised of the underlying U.S. Treasury benchmark rate, plus a credit spread premium for our debt security. At December 31, 2006, the fair value of these treasury locks was less than $0.1 million. To the extent effective, gains and losses on the value of the treasury locks will be deferred until the forecasted debt is issued and will be amortized to earnings over the life of the debt. No ineffectiveness was required to be recorded as of December 31, 2006.

NOTE 7. INVENTORIES

Inventories are valued at the lower of cost (based on weighted average cost method) or market. The costs of inventories did not exceed market values at December 31, 2006 and 2005. The major components of inventories were as follows:

	December 31, 2006	December 31, 2005
Crude oil (1)	$ 49,312	$ 3,021
Refined products and LPGs (2) (3)	7,636	11,864
Lubrication oils and specialty chemicals	7,500	5,740
Materials and supplies	7,029	8,203
Other	716	241
Total	$ 72,193	$ 29,069

(1) At December 31, 2006, the substantial majority of our crude oil inventory was subject to forward sales contracts.

(2) Refined products and LPGs inventory is managed on a combined basis.

(3) At December 31, 2006, we recorded a $1.5 million lower of cost or market adjustment related to our Downstream Segment's inventory.

NOTE 8. PROPERTY, PLANT AND EQUIPMENT

Major categories of property, plant and equipment for the years ended December 31, 2006 and 2005, were as follows:

	December 31, 2006	December 31, 2005
Land and right of way	$ 128,791	$ 147,064
Line pipe and fittings	1,218,226	1,434,392
Storage tanks	196,306	189,054
Buildings and improvements	58,973	51,596
Machinery and equipment	346,868	370,439
Construction work in progress	202,820	241,855
Total property, plant and equipment	$ 2,151,984	$ 2,434,400
Less accumulated depreciation and amortization	509,889	474,332
Net property, plant and equipment	$ 1,642,095	$ 1,960,068

Depreciation expense, including impairment charges, on property, plant and equipment was $78.9 million, $80.8 million and $80.7 million for the years ended December 31, 2006, 2005 and 2004, respectively. During the fourth quarter of 2004, we wrote off approximately $2.1 million in assets taken out of service to depreciation expense.

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

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

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

Asset Retirement Obligations

During 2006, we recorded $0.6 million of expense, included in depreciation and amortization expense, related to conditional AROs related to the retirement of the 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. Additionally, we have recorded a $1.2 million liability, which represents the fair values of these conditional AROs. During 2006, 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 asset retirement obligations:

Asset retirement obligation liability balance, December 31, 2005	$ —
Liabilities recorded	1,189
Liabilities settled	—
Accretion	39
Revision in estimates	—
Asset retirement obligation liability balance, December 31, 2006	$ 1,228

Property, plant and equipment at December 31, 2006, includes $0.5 million of asset retirement costs capitalized as an increase in the associated long-lived asset. Additionally, based on information currently available, we estimate that accretion expense will approximate $0.1 million for 2007, $0.1 million for 2008, $0.1 million for 2009, $0.2 million for 2010 and $0.2 million for 2011.

NOTE 9. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

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 the Seaway assets. Seaway owns a pipeline that carries mostly imported crude oil from a marine terminal at Freeport, Texas, to Cushing, Oklahoma, and from a marine terminal at Texas City, Texas, to refineries in the Texas City and Houston, Texas, areas. The Seaway Crude Pipeline Company Partnership Agreement provides for varying participation ratios throughout the life of Seaway. From June 2002 through December 31, 2005, we received 60% of revenue and expense of Seaway. The sharing ratio changed from 60% to 40% on May 12, 2006, and as such, or share of revenue and expense of Seaway was 47% for 2006. Thereafter, we receive 40% of revenue and expense of Seaway. During the years ended December 31, 2006, 2005 and 2004, we received distributions from Seaway of $20.5 million, $24.7 million and $36.9 million, respectively. During the years ended December 31, 2006, 2005 and 2004, we did not invest any funds in Seaway.

Centennial

In August 2000, TE Products entered into agreements with Panhandle Eastern Pipeline Company (“PEPL”), a former subsidiary of CMS Energy Corporation, and Marathon Petroleum Company LLC (“Marathon”) to form Centennial. Centennial owns an interstate refined petroleum products pipeline extending from the upper Texas Gulf Coast to central Illinois. Through February 9, 2003, each participant owned a one-third interest in Centennial. On February 10, 2003, TE Products and Marathon each acquired an additional 16.7% interest in Centennial from PEPL for $20.0 million each, increasing their ownership percentages in Centennial to 50% each. During the years ended December 31, 2006, 2005 and 2004, TE Products contributed $2.5 million, $0 and $1.5 million, respectively, to Centennial. TE Products has received no cash distributions from Centennial since its formation.

MB Storage

On January 1, 2003, TE Products and Louis Dreyfus Energy Services L.P. (“Louis Dreyfus”) formed Mont Belvieu Storage Partners, L.P. (“MB Storage”). TE Products and Louis Dreyfus each own a 50% ownership interest in MB Storage. MB Storage owns storage capacity at the Mont Belvieu fractionation and storage complex and a short haul transportation shuttle system that ties Mont Belvieu, Texas, to the upper Texas Gulf Coast energy marketplace. MB Storage is a service-oriented, fee-based venture serving the fractionation, refining and petrochemical industries with substantial capacity and flexibility for the transportation, terminaling and storage of NGLs, LPGs and refined products. MB Storage has no commodity trading activity. TE Products operates the facilities for MB Storage. Pursuant to a Federal Trade Commission (“FTC”) order and consent agreement, we expect to sell our interest in MB Storage and certain related pipelines during the first quarter of 2007 (see Note 18). Effective January 1, 2003, TE Products contributed property and equipment with a net book value of $67.1 million to MB Storage. Additionally, as of the contribution date, Louis Dreyfus had invested $6.1 million for expansion projects for MB Storage that TE Products was required to reimburse if the original joint development and marketing agreement was terminated by either party. This deferred liability was also contributed and credited to the capital account of Louis Dreyfus in MB Storage.

For the years ended December 31, 2006 and 2005, TE Products received the first $1.7 million per quarter (or $6.78 million on an annual basis) of MB Storage’s income before depreciation expense, as defined in the Agreement of Limited Partnership of MB Storage. For the year ended December 31, 2004, TE Products received the first $1.8 million per quarter (or $7.15 million on an annual basis) of MB Storage’s income before depreciation expense. TE Products’ share of MB Storage’s earnings is adjusted annually by the partners of MB Storage. Any amount of MB Storage’s annual income before depreciation expense in excess of $6.78 million for 2006 and 2005 and $7.15 million for 2004 was allocated evenly between TE Products and Louis Dreyfus. Depreciation expense on assets each party originally contributed to MB Storage is allocated between TE Products and Louis Dreyfus based on the net book value of the assets contributed. Depreciation expense on assets constructed or acquired by MB Storage subsequent to formation is allocated evenly between TE Products and Louis Dreyfus. For the years ended December 31, 2006, 2005 and 2004, TE Products' sharing ratios in the earnings of MB Storage was 59.4%, 64.2% and 69.4%, respectively. During the years ended December 31, 2006, 2005 and 2004, TE Products received distributions of $12.9 million, $12.4 million and $10.3 million, respectively, from MB Storage. During the years ended December 31, 2006, 2005 and 2004, TE Products contributed $4.8 million, $5.6 million and $21.4 million, respectively, to MB Storage. The 2005 contribution includes a combination of non-cash asset transfers of $1.4 million and cash contributions of $4.2 million. The 2004 contribution includes $16.5 million for the acquisition of storage and pipeline assets in April 2004. The remaining contributions have been for capital expenditures.

Summarized Financial Information for Seaway, Centennial and MB Storage

We use the equity method of accounting to account for our investments in Seaway, Centennial and MB Storage. Summarized combined financial information for Seaway, Centennial and MB Storage for the years ended December 31, 2006 and 2005, is presented below:

	For Year Ended December 31,	
	2006	2005
Revenues	$160,408	$164,494
Net income	34,070	52,623

Summarized combined balance sheet information for Seaway, Centennial and MB Storage as of December 31, 2006 and 2005, is presented below:

	December 31,	
	2006	2005
Current assets	$ 58,241	$ 60,082
Noncurrent assets	615,790	630,212
Current liabilities	37,663	32,242
Long-term debt	150,000	150,000
Noncurrent liabilities	6,055	13,626
Partners' capital	480,313	494,426

Jonah

On August 1, 2006, Enterprise, through its affiliate, Enterprise Gas Processing, LLC, became our joint venture partner by acquiring an interest in Jonah, the partnership through which we own an interest in the Jonah system. Prior to entering into the Jonah joint venture, Enterprise had managed the construction of the Phase V expansion and funded the initial costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and Enterprise plan to continue the Phase V expansion, which is expected to increase the system capacity of the Jonah system from 1.5 billion cubic feet ("Bcf") per day to approximately 2.3 Bcf per day and to significantly reduce system operating pressures, which is anticipated to lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is expected to increase the system gathering capacity to approximately 2.0 Bcf per day, is scheduled to be completed in the second quarter of 2007. The second portion of the expansion is expected to be completed by the end of 2007. The anticipated cost of the Phase V expansion is expected to be approximately $444.0 million. We expect to reimburse Enterprise for approximately 50% of these costs. To the extent the costs exceed an agreed upon base cost estimate of $415.2 million, we and Enterprise will each pay our respective ownership share (approximately 80% and 20%, respectively) of the expansion costs to that exceed the agreed upon base cost estimate.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Enterprise will continue to manage the Phase V construction project. We are entitled to all distributions from the joint venture until specified milestones are achieved, at which point Enterprise will be entitled to receive approximately 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. From August 1, 2006, we and Enterprise equally share the costs of the Phase V expansion. We have reimbursed Enterprise $109.4 million for 50% of the Phase V cost incurred by it (including its cost of capital of $1.3 million). At December 31, 2006, we had a payable to Enterprise for costs incurred through December 31, 2006, of $8.7 million. After subsequent milestones are achieved, we and Enterprise will share distributions based on a formula that takes into account the capital contributions of the parties, including expenditures by us prior to the expansion. Based on this formula in the partnership agreement, we expect to own an interest in Jonah of approximately 80%, with Enterprise owning the remaining 20% and serving as operator, with further costs being allocated based on such ownership interests. For the year ended December 31, 2006, our sharing ratio in the earnings of Jonah was 99.7%. During the year ended December 31, 2006, Jonah declared a distribution to us of $41.6 million, of which $30.0 was paid in cash and the remainder is reflected as a receivable from Jonah. During the year ended December 31, 2006, we contributed $121.0 million to Jonah. The joint venture is governed by a management committee comprised of two representatives approved by Enterprise and two representatives approved by us, each with equal voting power. This transaction was reviewed and recommended for approval by the Audit and Conflicts Committee of the Board of Directors of our General Partner.

Effective August 1, 2006, with the formation of the joint venture, Jonah was deconsolidated, and we began using the equity method of accounting to account for our investment in Jonah. Under the equity method, we record the costs of our investment within the “Equity Investments” line on our consolidated balance sheet, and as changes in the net assets of Jonah occur (for example, earnings, contributions and distributions), we will recognize our proportional share of that change in the ”Equity Investments” account.

Summarized financial information for Jonah for the period August 1, 2006 through December 31, 2006, is presented below:

Revenues	$79,618
Net income	34,743

Summarized balance sheet information for Jonah as of December 31, 2006, is presented below:

Current assets	$ 33,963
Noncurrent assets	800,591
Current liabilities	25,113
Noncurrent liabilities	191
Partners’ capital	809,250

NOTE 10. ACQUISITIONS

Mexia Pipeline

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

Storage and Terminaling Assets

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

Refined Products Terminal and Truck Rack

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

Genco Assets

On July 15, 2005, we acquired from Texas Genco LLC (“Genco”) all of its interests in certain companies that own a 90-mile pipeline system and 5.5 million barrels of storage capacity for $62.1 million. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price to property, plant and equipment. This acquisition was made as part of an expansion of our refined products origin capabilities in the Houston, Texas, and Texas City, Texas, areas. The assets of the purchased companies are being integrated into our Downstream Segment origin infrastructure in Texas City and Baytown, Texas. The integration and other system enhancements should be in service by the first quarter of 2007, at an estimated cost of $45.0 million. On October 6, 2006, we sold certain of these assets to an affiliate of Enterprise (see Note 11).

Terminal Assets

On July 14, 2006, we purchased assets from New York LP Gas Storage, Inc. for $10.0 million. The assets consist of two active caverns, one active brine pond, a four bay truck rack, seven above ground storage tanks, and a twelve-spot railcar rack located east of our Watkins Glen, New York facility. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price, net of liabilities assumed, primarily to property, plant and equipment and inventory.

Refined Products Terminal

Effective November 1, 2006, we purchased a refined petroleum product terminal in Aberdeen, Mississippi, for approximately $5.8 million from Mississippi Terminal and Marketing Inc. (“MTMI”). We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price primarily to property, plant and equipment, goodwill and intangible assets. We recorded $1.3 million of goodwill in this acquisition. The facility, located along the Tennessee-Tombigbee Waterway system, has storage capacity of 130,000 barrels for gasoline and diesel, which are supplied by barge for delivery to local markets, including Tupelo and Columbus, Mississippi. In connection with this acquisition, which we plan to integrate into our Downstream Segment, we plan to construct a new 500,000-barrel terminal in Boligee, Alabama, at a cost of approximately $20.0 million, on an 80-acre site which we are leasing from the Greene County Industrial Development Board under a 60-year agreement. The Boligee terminal site is located approximately two miles from Colonial Pipeline. The new terminal is expected to begin service during the fourth quarter of 2007.

Cavern Assets

On December 26, 2006, we purchased assets from Vectren Utility Holdings, Inc. for $4.8 million. The assets consist of one active 170,000 barrel LPG storage cavern, the associated piping and related equipment. These assets are located adjacent to our Todhunter facility near Middleton, Ohio and tie into our existing LPG pipeline. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price primarily to property, plant and equipment.

NOTE 11. DISPOSITIONS AND DISCONTINUED OPERATIONS

Pioneer Plant

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

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the years ended December 31, 2006, 2005 and 2004, are presented below:

	For Year Ended December 31,		
	2006	2005	2004
Operating revenues:			
Sales of petroleum products	$ 3,828	$ 10,479	$ 7,295
Other	932	2,975	2,807
Total operating revenues	4,760	13,454	10,102
Costs and expenses:			
Purchases of petroleum products	3,000	8,870	5,944
Operating expense	182	692	738
Depreciation and amortization	51	612	610
Taxes – other than income taxes	30	130	121
Total costs and expenses	3,263	10,304	7,413
Income from discontinued operations	$ 1,497	$ 3,150	$ 2,689

Assets of the discontinued operations consisted of the following at December 31, 2005:

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

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Cash flows from discontinued operations for the years ended December 31, 2006, 2005 and 2004, are presented below:

	For Year Ended December 31, 2006	2005	2004
Cash flows from discontinued operating activities:			
Net income	$ 19,369	$ 3,150	$ 2,689
Depreciation and amortization	51	612	610
Gain on sale of Pioneer plant	(17,872)	—	—
(Increase) decrease in inventories	(27)	20	(28)
Net cash flows provided by discontinued operating activities	1,521	3,782	3,271
Cash flows from discontinued investing activities:			
Capital expenditures	—	—	(7,398)
Net cash flows used in discontinued investing activities	—	—	(7,398)
Net cash flows from discontinued operations	$ 1,521	$ 3,782	$ (4,127)

Crude oil and Refined Products Assets

On October 6, 2006, we sold certain crude oil pipeline assets and refined products pipeline assets in the Houston, Texas area, to an affiliate of Enterprise for approximately $11.7 million. These assets, which have been idle since acquisition, were part of the assets acquired by us in 2005 from Genco and BP (see Note 10). The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of these pipeline assets was approximately $6.0 million. We recognized a gain of $5.7 million on this transaction.

NOTE 12. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table presents the carrying amount of goodwill at December 31, 2006 and 2005, by business segment:

	Downstream Segment	Midstream Segment	Upstream Segment	Segments Total
Goodwill:				
December 31, 2006 (1)	$1,339	$ —	$14,167	$15,506
December 31, 2005	—	2,777	14,167	16,944

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah was deconsolidated and has been subsequently accounted for as an equity investment (see Note 9). On November 1, 2006, we acquired a refined products terminal, and recorded $1.3 million of goodwill.

Other Intangible Assets

The following table reflects the components of intangible assets, including excess investments, being amortized at December 31, 2006 and 2005:

	December 31, 2006		December 31, 2005	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible assets:				
Gathering and transportation agreements (1)	$ 241,537	$ (87,121)	$ 464,337	$ (118,921)
Fractionation agreement	38,000	(16,625)	38,000	(14,725)
Other	12,310	(2,691)	10,226	(2,009)
Subtotal	$ 291,847	$ (106,437)	$ 512,563	$ (135,655)
Excess investments:				
Centennial Pipeline LLC	$ 33,390	$ (16,579)	$ 33,390	$ (12,947)
Seaway Crude Pipeline Company	26,908	(4,450)	27,100	(3,764)
Jonah Gas Gathering Company	2,924	—	—	—
Subtotal	$ 63,222	$ (21,029)	$ 60,490	$ (16,711)
Total intangible assets	$ 355,069	$ (127,466)	$ 573,053	$ (152,366)

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise, Jonah was deconsolidated and has been subsequently accounted for as an equity investment (see Note 9).

SFAS 142 requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. Amortization expense on intangible assets was $28.8 million, $30.5 million and $32.2 million for the years ended December 31, 2006, 2005 and 2004, respectively. Amortization expense on excess investments included in equity earnings was $4.3 million, $4.8 million and $3.8 million for the years ended December 31, 2006, 2005 and 2004, respectively.

The values assigned to our intangible assets for natural gas gathering contracts on the Val Verde system are amortized on a unit-of-production basis, based upon the actual throughput of the systems compared to the expected total throughput for the lives of the contracts. On a quarterly basis, we may obtain limited production forecasts and updated throughput estimates from some of the producers on the system, and as a result, we evaluate the remaining expected useful lives of the contract assets based on the best available information. During the quarter ended September 30, 2006, we received updated limited production estimates from some of the producers on the Val Verde system, which reduced the future production forecast. We revised the units-of-production calculation for Val Verde, which increased amortization expense by approximately $0.2 million per month. Further revisions to these estimates may occur as additional production information is made available to us.

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

The value assigned to our excess investment in Centennial was created upon its formation. Approximately $30.0 million is related to a contract and is being amortized on a unit-of-production basis based upon the volumes transported under the contract compared to the guaranteed total throughput of the contract over a 10-year life. The remaining $3.4 million is related to a pipeline and is being amortized on a straight-line basis over the life of the pipeline, which is 35 years. The value assigned to our excess investment in Seaway was created upon acquisition of our 50% ownership interest in 2000. We are amortizing the $27.1 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to the life of the pipeline. The value assigned to our excess investment in Jonah was created as a result of interest capitalized on the construction of Jonah's expansion. We will continue to capitalize interest on the construction of the expansion of the Jonah system until the construction is completed and placed into service. When the expansion is placed into service, we will amortize the excess investment in Jonah on a straight-line basis over life of the assets constructed.

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 (1)	Excess Investments
2007	$23,194	$4,440
2008	20,664	4,588
2009	18,053	4,793
2010	18,034	3,587
2011	18,026	885

(1) Excludes estimated amortization expense of Jonah's intangible assets as a result of its deconsolidation effective August 1, 2006.

NOTE 13. DEBT OBLIGATIONS

The following table summarizes the principal amounts outstanding under all of our debt instruments as of December 31, 2006 and 2005:

	December 31, 2006	December 31, 2005
Revolving Credit Facility, due December 2011	$ 490,000	$ 405,900
6.45% TE Products Senior Notes, due January 2008	179,968	179,937
7.625% Senior Notes, due February 2012	498,866	498,659
6.125% Senior Notes, due February 2013	199,130	198,988
7.51% TE Products Senior Notes, due January 2028	210,000	210,000
Total borrowings	1,577,964	1,493,484
Adjustment to carrying value associated with hedges of fair value	25,323	31,537
Total Credit Facilities	$ 1,603,287	$ 1,525,021

Revolving Credit Facility

We have in place a $700.0 million unsecured revolving credit facility, including the issuance of letters of credit ("Revolving Credit Facility"), which matures on December 13, 2011. Commitments under the credit facility may be increased up to a maximum of $850.0 million upon our request, subject to lender approval and the satisfaction of certain other conditions. The interest rate is based, at our option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. Financial covenants in the Revolving Credit Facility require that we maintain a ratio of Consolidated Funded Debt to Pro Forma EBITDA (as defined and calculated in the facility) of less than 4.75 to 1.00 (subject to adjustment for specified acquisitions) and a ratio of EBITDA to Interest Expense (as defined and calculated in the facility) of at least 3.00 to 1.00, in each case with respect to specified twelve month periods. Other restrictive covenants in the Revolving Credit Facility limit our ability to, among other things, incur additional indebtedness, make distributions in excess of Available Cash (see Note 14), incur liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets.

On July 31, 2006, we amended our Revolving Credit Facility. The primary revisions were as follows:

- The maturity date of the credit facility was extended from December 13, 2010 to December 13, 2011. Also under the terms of the amendment, we may request up to two one-year extensions of the maturity date. These extensions, if requested, will become effective subject to lender approval and satisfaction of certain other conditions.
- The amendment releases Jonah as a guarantor of the Revolving Credit Facility and 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 principal aggregate amount of $50.0 million.
- The amendment modifies the financial covenants to, among other things, allow us to include in the calculation of our Consolidated EBITDA (as defined in the Revolving Credit Facility) pro forma adjustments for material capital projects.
- The amendment allows for the issuance of Hybrid Securities (as defined in the Revolving Credit Facility) of up to 15% of our Consolidated Total Capitalization (as defined in the Revolving Credit Facility).

At December 31, 2006, $490.0 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 5.96%. At December 31, 2006, we were in compliance with the covenants of this credit facility.

Senior Notes

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

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

On February 20, 2002, we issued $500.0 million principal amount of 7.625% Senior Notes due 2012. The 7.625% Senior Notes were issued at a discount of $2.2 million and are being accreted to their face value over the term of the notes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 7.625% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2006, we were in compliance with the covenants of these Senior Notes.

On January 30, 2003, we issued $200.0 million principal amount of 6.125% Senior Notes due 2013. The 6.125% Senior Notes were issued at a discount of $1.4 million and are being accreted to their face value over the term of the notes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 6.125% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2006, we were in compliance with the covenants of these Senior Notes.

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

		Fair Value December 31,	
	Face Value	2006	2005
6.45% TE Products Senior Notes, due January 2008	$180.0	$181.6	$183.7
7.625% Senior Notes, due February 2012	500.0	537.1	552.0
6.125% Senior Notes, due February 2013	200.0	201.6	205.6
7.51% TE Products Senior Notes, due January 2028	210.0	221.5	224.1

We have entered into interest rate swap agreements to hedge our exposure to changes in the fair value on a portion of the Senior Notes discussed above (see Note 6).

Letter of Credit

At December 31, 2006, we had outstanding an $8.7 million standby letter of credit in connection with crude oil purchased during the fourth quarter of 2006. The payable related to these purchases of crude oil is expected to be paid during the first quarter of 2007.

NOTE 14. PARTNERS' CAPITAL AND DISTRIBUTIONS

Equity Offerings

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

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

Quarterly Distributions of Available Cash

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

	Unitholders	General Partner
Quarterly Cash Distribution per Unit:		
Up to Minimum Quarterly Distribution ($0.275 per Unit)	98%	2%
First Target – $0.276 per Unit up to $0.325 per Unit	85%	15%
Second Target – $0.326 per Unit up to $0.45 per Unit	75%	25%
Over Second Target – Cash distributions greater than $0.45 per Unit (1)	50%	50%

(1) Effective December 8, 2006, upon approval of our unitholders, our Partnership Agreement was amended and the 50%/50% distribution tier was eliminated in exchange for the issuance of 14,091,275 Units to the General Partner (see Note 1).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table reflects the allocation of total distributions paid during the years ended December 31, 2006, 2005 and 2004:

	Years Ended December 31,		
	2006	2005	2004
Limited Partner Units	$ 196,665	$ 177,916	$ 166,158
General Partner Ownership Interest	4,014	3,630	3,391
General Partner Incentive	77,887	69,555	63,508
Total Cash Distributions Paid	$ 278,566	$ 251,101	$ 233,057
Total Cash Distributions Paid Per Unit	$ 2.70	$ 2.68	$ 2.64

On February 7, 2007, we paid a cash distribution of $0.675 per Unit for the quarter ended December 31, 2006. The fourth quarter 2006 cash distribution totaled $72.4 million.

General Partner’s Incentive Distribution Rights

On December 8, 2006, our Partnership Agreement was amended. We issued 14,091,275 Units to our General Partner in exchange for a reduction in its maximum percentage interest in our quarterly distributions from 50% to 25% with respect to that portion of our quarterly cash distribution to partners that exceeds $0.325 per Unit (see Note 1).

General Partner’s Interest

As of December 31, 2006 and 2005, we had deficit balances of $85.7 million and $61.5 million, respectively, in our General Partner’s equity account. These negative balances do not represent assets to us and do not represent obligations of the General Partner to contribute cash or other property to us. The General Partner’s equity account generally consists of its cumulative share of our net income less cash distributions made to it plus capital contributions that it has made to us (see our Statements of Consolidated Partners’ Capital for a detail of the General Partner’s equity account). For the years ended December 31, 2006, 2005 and 2004, the General Partner was allocated $57.7 million (representing 28.57%), $47.6 million (representing 29.27%) and $40.0 million (representing 28.85%), respectively, of our net income and received $81.9 million, $73.2 million and $66.9 million, respectively, in cash distributions.

Capital Accounts, as defined under our Partnership Agreement, are maintained for our General Partner and our limited partners. The Capital Account provisions of our Partnership Agreement incorporate principles established for U.S. federal income tax purposes and are not comparable to the equity accounts reflected under accounting principles generally accepted in the United States in our financial statements. In connection with the amendment of our Partnership Agreement, the General Partner’s obligation to make capital contributions to maintain its 2% capital account was eliminated.

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

Cash distributions that we make during a period may exceed our net income for the period. We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its reasonable discretion. Cash distributions in excess of net income allocations and capital contributions during the years ended December 31, 2006 and 2005, resulted in a deficit in the General Partner’s equity account at December 31, 2006 and 2005. Future cash distributions that exceed net income will result in an increase in the deficit balance in the General Partner's equity account.

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

Accumulated Other Comprehensive Income

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 year ended December 31, 2006, the components of accumulated other comprehensive income reflected on our consolidated balance sheets were composed of crude oil hedges and interest rate swaps. The crude oil hedges mature in December 2006 and December 2007. While the crude oil hedges are in effect, changes in their fair values, to the extent the hedges are effective, are recognized in accumulated other comprehensive income until they are recognized in net income in future periods. The interest rate swaps mature in January 2008, are related to our variable rate revolving credit facility and are designated as cash flow hedges beginning in the third quarter of 2006.

The accumulated balance of other comprehensive income related to our cash flow hedges and gains and losses associated with our pension benefits is as follows:

Balance at December 31, 2003	$ (2,902)
Transferred to earnings	2,939
Change in fair value of cash flow hedge	(37)
Balance at December 31, 2004	—
Change in fair value of cash flow hedge	11
Balance at December 31, 2005	11
Transferred to earnings	2,255
Changes in fair values of interest rate cash flow hedges	(2,503)
Changes in fair values of crude oil cash flow hedges	730
Adjustment to initially apply SFAS No. 158	(67)
Balance at December 31, 2006	$ 426

NOTE 15. BUSINESS SEGMENTS

We have three reporting segments:

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

Our Downstream Segment revenues are earned from transportation, marketing and storage of refined products and LPGs, intrastate 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 these operations are somewhat seasonal. Refined products volumes are generally higher during the second and third quarters because of greater demand for gasolines during the spring and summer driving seasons. LPGs volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating. 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 investments in MB Storage, which we are required to divest (see Note 18), and in Centennial (see Note 9).

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale or delivery of the crude oil to local refineries, marketers or other end users. Revenues are also generated from trade documentation and pumpover services, primarily at Cushing, Oklahoma, and Midland, Texas. Our Upstream Segment also includes our equity investment in Seaway (see Note 9). Seaway consists of large diameter pipelines that transport crude oil from Seaway’s marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

Our Midstream Segment revenues are earned from the gathering of coal bed methane and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde; transportation of NGLs from two trunkline NGL pipelines in South Texas, two NGL pipelines in East Texas and a pipeline system (Chaparral) from West Texas and New Mexico to Mont Belvieu; and the fractionation of NGLs in Colorado. Our Midstream Segment also includes our equity investment in Jonah (see Note 9). Jonah, which is a joint venture between us and an affiliate of Enterprise, owns a natural gas gathering system in the Green River Basin in southwestern Wyoming. Prior to August 1, 2006, when Jonah was wholly-owned by us, operating results for Jonah were included in the consolidated Midstream Segment operating results. Effective August 1, 2006, we entered into the joint venture with Enterprise’s affiliate, upon which Jonah was deconsolidated, and its operating results since August 1, 2006, have been accounted for under the equity method of accounting. Operating results of the Pioneer plant, which we sold to an Enterprise affiliate in March 2006, are shown as discontinued operations for the years ended December 31, 2006 and 2005.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The tables below include financial information by reporting segment for the years ended December 31, 2006, 2005 and 2004:

	For Year Ended December 31, 2006					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products (1)	$ 5,800	$ 9,060,782	$ 18,766	$ 9,085,348	$ (4,832)	$ 9,080,516
Operating revenues	298,501	48,847	182,503	529,851	(2,882)	526,969
Purchases of petroleum products(1)	5,526	8,953,407	17,272	8,976,205	(9,143)	8,967,062
Operating expenses, including power and taxes – other than income taxes	153,246	66,801	59,150	279,197	(749)	278,448
General and administrative expenses	17,085	5,986	8,277	31,348	—	31,348
Depreciation and amortization expense	41,405	14,400	52,447	108,252	—	108,252
Gains on sales of assets	(4,223)	(1,805)	(1,376)	(7,404)	—	(7,404)
Operating income	91,262	70,840	65,499	227,601	2,178	229,779
Equity earnings (losses)	(8,018)	11,905	35,052	38,939	(2,178)	36,761
Interest income	1,008	407	662	2,077	—	2,077
Other income, net	494	388	6	888	—	888
Earnings before interest expense, deferred income tax expense and discontinued operations	$ 84,746	$ 83,540	$ 101,219	$ 269,505	$ —	$ 269,505

(1) Amounts for the period from April 1, 2006 through December 31, 2006 have been fully adjusted for the impact of adopting EITF 04-13. The period from January 1, 2006 through March 31, 2006 and for the years ended December 31, 2005 and 2004 have not been adjusted for the adoption of EITF 04-13, as retroactive restatement was not permitted, which impacts comparability (see Note 3 for further information).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	For Year Ended December 31, 2005					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 8,062,131	$ —	$ 8,062,131	$ (323)	$ 8,061,808
Operating revenues	287,191	48,108	211,171	546,470	(3,244)	543,226
Purchases of petroleum products	—	7,989,682	—	7,989,682	(3,244)	7,986,438
Operating expenses, including power and taxes – other than income taxes	142,131	63,263	50,288	255,682	(323)	255,359
General and administrative expenses	17,653	7,077	8,413	33,143	—	33,143
Depreciation and amortization expense	39,403	17,161	54,165	110,729	—	110,729
Gains on sales of assets	(139)	(118)	(411)	(668)	—	(668)
Operating income	88,143	33,174	98,716	220,033	—	220,033
Equity earnings (losses)	(2,984)	23,078	—	20,094	—	20,094
Interest income	477	—	210	687	—	687
Other income, net	278	156	14	448	—	448
Earnings before interest expense, deferred income tax expense and discontinued operations	$ 85,914	$ 56,408	$ 98,940	$ 241,262	$ —	$ 241,262

	For Year Ended December 31, 2004					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 5,426,832	$ —	$ 5,426,832	$ —	$ 5,426,832
Operating revenues	279,400	49,163	195,902	524,465	(3,207)	521,258
Purchases of petroleum products	—	5,370,234	—	5,370,234	(3,207)	5,367,027
Operating expenses, including power and taxes – other than income taxes	148,644	55,459	53,269	257,372	—	257,372
General and administrative expenses	16,884	5,434	5,698	28,016	—	28,016
Depreciation and amortization expense	43,135	13,130	56,019	112,284	—	112,284
Gains on sales of assets	(526)	(527)	—	(1,053)	—	(1,053)
Operating income	71,263	32,265	80,916	184,444	—	184,444
Equity earnings (losses)	(6,544)	28,692	—	22,148	—	22,148
Interest income	309	43	115	467	—	467
Other income, net	478	363	12	853	—	853
Earnings before interest expense, deferred income tax expense and discontinued operations	$ 65,506	$ 61,363	$ 81,043	$ 207,912	$ —	$ 207,912

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table provides the total assets, capital expenditures and significant non-cash investing activities for each segment as of and for the years ended December 31, 2006, 2005 and 2004:

	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
December 31, 2006:						
Total assets	$1,160,929	$1,504,699	$1,335,502	$4,001,130	$(79,038)	$3,922,092
Capital expenditures	75,344	48,351	42,929	166,624	3,422	170,046
Non-cash investing activities	—	—	581,341	581,341	—	581,341
December 31, 2005:						
Total assets	$1,056,217	$1,353,492	$1,280,548	$3,690,257	$ (9,719)	$3,680,538
Capital expenditures	58,609	40,954	119,837	219,400	1,153	220,553
Non-cash investing activities	1,429	—	—	1,429	—	1,429
December 31, 2004:						
Total assets	$ 959,042	$1,069,007	$1,184,184	$3,212,233	$(25,949)	$3,186,284
Capital expenditures	80,930	37,448	37,677	156,055	694	156,749
Capital expenditures for discontinued operations	—	—	7,398	7,398	—	7,398

The following table reconciles the segment data from the tables above to consolidated net income for the years ended December 31, 2006, 2005 and 2004:

	For Year Ended December 31, 2006	2005	2004
Earnings before interest expense, deferred income tax expense and discontinued operations	$ 269,505	$ 241,262	$ 207,912
Interest expense – net	(86,171)	(81,861)	(72,053)
Income before deferred income tax expense	183,334	159,401	135,859
Deferred income tax expense	652	—	—
Income from continuing operations	182,682	159,401	135,859
Discontinued operations	19,369	3,150	2,689
Net income	$ 202,051	$ 162,551	$ 138,548

NOTE 16. RELATED PARTY TRANSACTIONS

EPCO and Affiliates and Duke Energy, DEFS and Affiliates

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

The following information summarizes our business relationships and related transactions with EPCO and its affiliates, including entities controlled by Dan L. Duncan, and DEFS and its affiliates during the years ended

December 31, 2006, 2005 and 2004. We have also provided information regarding our business relationships and transactions with our unconsolidated 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;
- DFI, which owns and controls our General Partner;
- Enterprise Products Partners L.P., which is controlled by affiliates of EPCO;
- Duncan Energy Partners L.P., which is controlled by affiliates of EPCO; and
- Enterprise Gas Processing LLC, which is controlled by affiliates of EPCO and is our joint venture partner in Jonah.

EPCO, a private company controlled by Dan L. Duncan, also owns DFI, which owns and controls our General Partner. DFI 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 depends on the cash distributions it receives from our General Partner and other investments to fund its other operations and to meet its debt obligations. We paid cash distributions of $81.9 million and $73.2 million during the years ended December 31, 2006 and 2005, to our General Partner.

The ownership interests in us that are owned or controlled by EPCO and 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. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, Enterprise and us. The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility.

Unless noted otherwise, our agreements with EPCO are not the result of arm's length transactions. As a result, we cannot provide assurance that the terms and provisions of such agreements are at least as favorable to us as we could have obtained from unaffiliated third parties.

Administrative Services Agreement

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the ASA. We and our General Partner, Enterprise and its general partner, Enterprise GP Holdings L.P. and its general partner, Duncan Energy Partners L.P. and its general partner and certain affiliated entities are parties to the ASA. The significant terms of the ASA are as follows:

- EPCO provides administrative, management, engineering and operating services as may be necessary to manage and operate our business, properties and assets (in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.
- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including EPCO expenses reasonably allocated to us). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.
- EPCO allows us to participate as named insureds in its overall insurance program with the associated costs being allocated to us.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Our operating costs and expenses for the years ended December 31, 2006 and 2005 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets.

Likewise, our general and administrative costs for the years ended December 31, 2006 and 2005 include amounts we reimburse to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity's business and affairs).

EPCO and its affiliates have no obligation to present business opportunities to us or our Operating Partnerships, and we and our Operating Partnerships have no obligation to present business opportunities to EPCO and its affiliates. However, the ASA requires that business opportunities offered to or discovered by EPCO, which controls both us and our affiliates and Enterprise and it affiliates, be offered first to certain Enterprise affiliates before they may be pursued by EPCO and its other affiliates or offered to us.

The following table summarizes the related party transactions with EPCO and affiliates and DEFS and affiliates for the years ended December 31, 2006, 2005 and 2004 (in millions):

	For Year Ended December 31,		
	2006	2005	2004
Revenues from EPCO and affiliates: (1)			
Sales of petroleum products (2)	$ 3.2	$ —	$ —
Transportation – NGLs (3)	10.2	7.4	—
Transportation – LPGs(4)	3.6	4.3	—
Other operating revenues (5)	1.5	0.3	—
Costs and Expenses from EPCO and affiliates: (1)			
Payroll, administrative and other (6)(7)	136.9	78.0	—
Purchases of petroleum products (8)	41.8	3.4	—
Revenues from DEFS and affiliates: (9)			
Sales of petroleum products	—	4.3	23.2
Transportation – NGLs	—	2.8	16.7
Gathering – Natural gas – Jonah	—	0.5	3.3
Transportation – LPGs	—	0.7	2.6
Other operating revenues	—	2.4	14.0
Costs and Expenses from DEFS and affiliates: (9)			
Payroll, administrative and other (10)(11)(12)	—	17.4	102.4
Purchases of petroleum products (13)	—	38.5	146.4

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

(2) Includes Jonah NGL sales through July 31, 2006 of $2.9 million to Enterprise Gas Processing, LLC and $0.3 million in sales from Lubrication Services, L.P. ("LSI") to various EPCO affiliates.

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

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

(5) Includes other operating revenues on the TE Products pipeline.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(6) Includes payroll, payroll related expenses, administrative expenses, including reimbursements related to employee benefits and employee benefit plans, incurred in managing us and our subsidiaries in accordance with the ASA, and other operating expenses.

(7) Includes insurance expense for the years ended December 31, 2006 and 2005, related to premiums paid by EPCO of $15.8 million and $9.8 million, respectively. Beginning February 24, 2005, the majority of our insurance coverage, including property, liability, business interruption, auto and directors and officers' liability insurance, was obtained through EPCO.

(8) Includes TCO purchases of condensate of $41.6 million, Jonah processing fees through July 31, 2006 of $0.1 million and $0.1 million of expenses related to LSI's use of an affiliate of EPCO as a transporter.

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

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

(11) Includes costs related to payroll, payroll related expenses and administrative expenses incurred in managing us and our subsidiaries.

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

(13) Includes TCO purchases of condensate and $0.8 million of purchases by Jonah's Pioneer processing plant which is classified as income from discontinued operations in the consolidated financial statements.

The following table summarizes the related party balances with EPCO and affiliates at December 31, 2006 and 2005 (in millions):

	December 31,	
	2006	2005
Accounts receivable, related party (1)	$ 0.3	$4.3
Gas imbalance receivable	1.3	—
Insurance reimbursement receivable	1.4	1.3
Accounts payable, related party (2)	26.4	9.8
Deferred revenue, related party	0.3	—
Long-term payable (3)	1.8	—

(1) Relates to sales and transportation services provided to EPCO and affiliates.

(2) Relates to direct payroll, payroll related costs and other operational related charges from EPCO and afffiliates.

(3) Relates to our share of EPCO's Oil Insurance Limited insurance program retrospective premiums obligation.

Sale of Pioneer plant

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

Jonah Joint Venture

On August 1, 2006, Enterprise (through an affiliate) became our joint venture partner by acquiring an interest in Jonah, the partnership through which we owned the Jonah system. We have reimbursed Enterprise $109.4 million for 50% of the Phase V cost incurred by it (including its cost of capital of $1.3 million). At December 31, 2006, we had a payable to Enterprise for costs incurred through December 31, 2006, of $8.7 million (see Note 9 for further discussion on the Jonah joint venture).

In conjunction with the formation of the joint venture, we have agreed to indemnify Enterprise 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 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 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 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 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.

Other Transactions

On October 6, 2006, we sold certain crude oil pipeline assets and refined products pipeline assets in the Houston, Texas area, to an affiliate of Enterprise for approximately $11.7 million. These assets, which had been idle since acquisition, were part of the assets acquired by us in 2005 from Genco and BP. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of these pipeline assets at September 30, 2006, was approximately $6.0 million. We recognized a gain of $5.7 million on this transaction.

On November 1, 2006, we announced plans to construct a new 20-inch diameter lateral pipeline to connect our mainline system to the Enterprise and MB Storage facilities at Mont Belvieu, Texas, at a cost of approximately $8.6 million. The new connection, which provides delivery from Enterprise of propane into our system at full line flow rates, complements our current ability to source product from MB Storage. The new connection also offers the ability to deliver other liquid products such as butanes and natural gasoline from Enterprise's storage facilities into our system at reduced flow rates until enhancements can be made. The capability to deliver butanes and natural gasoline from MB Storage at full flow rates is not expected to be impacted. Construction of the new connection was completed and placed in service in December 2006. This new pipeline replaces a 10-mile, 18-inch segment of pipeline that we sold to an Enterprise affiliate in January 2007 (see Note 23).

We have entered into a lease with DEP, for a 12-mile, 10-inch interconnecting pipeline extending from Pasadena, Texas to Baytown, Texas. The primary term of this lease will expire on September 15, 2007, and will continue on a month-to-month basis subject to termination by either party upon 60 days' notice.

Relationships with Unconsolidated Subsidiaries

Centennial

TE Products has a 50% ownership interest in Centennial (see Note 9). TE Products has entered into a management agreement with Centennial to operate Centennial's terminal at Creal Springs, Illinois, and pipeline connection in Beaumont, Texas. For each of the years ended December 31, 2006, 2005 and 2004, we recognized management fees of $0.2 million from Centennial, and actual operating expenses billed to Centennial were $7.4 million, $3.7 million and $6.9 million, respectively.

TE Products also has a joint tariff with Centennial to deliver products at TE Products' locations using Centennial's pipeline as part of the delivery route to connecting carriers. TE Products, as the delivering pipeline, invoices the shippers for the entire delivery rate, records only the net rate attributable to it as transportation revenues and records a liability for the amounts due to Centennial for its share of the tariff. In addition, TE Products performs ongoing construction services for Centennial and bills Centennial for labor and other costs to perform the construction. At December 31, 2006 and 2005, we had net payable balances of $4.4 million and $1.4 million, respectively, to Centennial for its share of the joint tariff deliveries and other operational related charges, partially offset by the reimbursement due to us for construction services provided to Centennial.

In January 2003, TE Products entered into a pipeline capacity lease agreement with Centennial for a period of five years that contains a minimum throughput requirement. For the years ended December 31, 2006, 2005 and 2004, TE Products incurred $5.6 million, $5.9 million and $5.3 million, respectively, of rental charges related to the lease of pipeline capacity on Centennial.

Jonah

An affiliate of Enterprise operates the Jonah assets. TCO purchases NGLs from Jonah as part of its crude oil marketing activities. During the period August 1, 2006 through December 31, 2006, TCO incurred $2.2 million in purchases from Jonah related to the crude oil marketing activities. At December 31, 2006, we had a distribution receivable of $11.5 million from Jonah, which is included in accounts receivable, related parties.

Seaway

We own a 50% ownership interest in Seaway, and the remaining 50% interest is owned by ConocoPhillips (see Note 9). We operate the Seaway assets. During the years ended December 31, 2006, 2005 and 2004, we billed Seaway $7.6 million, $8.5 million and $7.6 million, respectively, for direct payroll and payroll related expenses for operating Seaway. Additionally, for each of the years ended December 31, 2006, 2005 and 2004, we billed Seaway $2.1 million for indirect management fees for operating Seaway. At December 31, 2006 and 2005, we had payable balances to Seaway of $1.4 million and $0.6 million, respectively, for advances Seaway paid to us as operator for operating costs, including payroll and related expenses and management fees.

MB Storage

Effective January 1, 2003, TE Products entered into agreements with Louis Dreyfus to form MB Storage (see Note 9). TE Products operates the facilities for MB Storage. TE Products and MB Storage have entered into a pipeline capacity lease agreement, and for each of the years ended December 31, 2006, 2005 and 2004, TE Products recognized $0.1 million in rental revenue related to this lease agreement. During the years ended December 31, 2006, 2005 and 2004, TE Products also billed MB Storage $3.1 million, $3.6 million and $3.2 million, respectively, for direct payroll and payroll related expenses for operating MB Storage. At December 31, 2006, TE Products had a net payable balance to MB Storage of $2.3 million for operating costs, including payroll and related expenses for

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

operating MB Storage. At December 31, 2005, TE Products had a net receivable balance from MB Storage of $0.9 million for operating costs, including payroll and related expenses for operating MB Storage.

NOTE 17. EARNINGS PER UNIT

Basic earnings per Unit is computed by dividing net income or loss allocated to limited partner interest by the weighted average number of Units outstanding during a period. We currently have no dilutive securities outstanding. The amount of net income allocated to limited partner interest is derived by subtracting our General Partner's share of the net income from net income.

The following table shows the allocation of net income to our General Partner for the years ended December 31, 2006, 2005, and 2005:

	For Year Ended December 31,		
	2006	2005	2004
Income from continuing operations	$ 182,682	$ 159,401	$ 135,859
Discontinued operations	19,369	3,150	2,689
Net income	202,051	162,551	138,548
Multiplied by General Partner interest in net income	28.57%	29.27%	28.85%
Earnings allocated to General Partner:			
Income from continuing operations	52,199	46,657	39,192
Discontinued operations	5,534	922	776
Net income	57,733	47,579	39,968
BASIC AND DILUTED EARNINGS PER UNIT:			
Numerator:			
Income from continuing operations	130,483	112,744	96,667
Discontinued operations	13,835	2,228	1,913
Limited partners' interest in net income	144,318	114,972	98,580
Denominator:			
Weighted average limited partner Units outstanding	73,657	67,397	62,999
Basic and diluted earnings per Unit:			
Continuing operations	$ 1.77	$ 1.67	$ 1.53
Discontinued operations	0.19	0.04	0.03
Limited partners' interest in net income	$ 1.96	$ 1.71	$ 1.56

The General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase, in accordance with our Partnership Agreement. On December 8, 2006, our Partnership Agreement was amended (see Note 1), and our General Partner's maximum percentage interest in our quarterly distributions was reduced from 50% to 25%. We issued 14.1 million Units on December 8, 2006 to our General Partner as consideration for the IDR Reduction Amendment. The number of Units issued to our General Partner was based upon a predetermined formula that, based on the distribution rate and the number of Units outstanding at the time of the issuance, resulted in our General Partner receiving cash distributions from the newly-issued Units and from its reduced maximum percentage interest in our quarterly distributions approximately equal to the cash distributions our General Partner would have received from its maximum percentage interest in our quarterly distributions without the IDR Reduction Amendment.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

At December 31, 2006, 2005 and 2004, we had outstanding 89,804,829, 69,963,554 and 62,998,554 Units, respectively. We issued 14,091,275 Units to our General Partner on December 8, 2006. During 2006, we issued 5,000,000 Units and 750,000 Units on July 5, 2006 and July 12, 2006, respectively, in an underwritten public offering. During 2005, we issued 6,100,000 Units and 865,000 Units on May 11, 2005 and June 8, 2005, respectively. No Units were issued in 2004.

NOTE 18. COMMITMENTS AND CONTINGENCIES

Litigation

In the fall of 1999, the General Partner and TE Products were named as defendants in a lawsuit in Jackson County Circuit Court, Jackson County, Indiana, styled *Ryan E. McCleery and Marcia S. McCleery, et al. and Michael and Linda Robson, et al. v. Texas Eastern Corporation, et al.* In the lawsuit, the plaintiffs contend, among other things, that we and other defendants stored and disposed of toxic and hazardous substances and hazardous wastes in a manner that caused the materials to be released into the air, soil and water. They further contend that the release caused damages to the plaintiffs. In their complaint, the plaintiffs allege strict liability for both personal injury and property damage together with gross negligence, continuing nuisance, trespass, criminal mischief and loss of consortium. The plaintiffs are seeking compensatory, punitive and treble damages. On March 18, 2005, we entered into Release and Settlement Agreements with the McCleery plaintiffs dismissing all of these plaintiffs' claims on terms that did not have a material adverse effect on our financial position, results of operations or cash flows. Although we did not settle with all plaintiffs and we therefore remain named parties in the *Michael and Linda Robson, et al. v. Texas Eastern Corporation, et al*. action, a co-defendant has agreed, by Cooperative Defense Agreement, to fund the defense and satisfy all final judgments which might be rendered with the remaining claims asserted against us. Consequently, we do not believe that the outcome of these remaining claims will have a material adverse effect on our financial position, results of operations or cash flows.

On December 21, 2001, TE Products was named as a defendant in a lawsuit in the 10th Judicial District, Natchitoches Parish, Louisiana, styled *Rebecca L. Grisham et al. v. TE Products Pipeline Company, Limited Partnership*. In this case, the plaintiffs contend that our pipeline, which crosses the plaintiffs' property, leaked toxic products onto their property and, consequently caused damages to them. We have filed an answer to the plaintiffs' petition denying the allegations, and we are defending ourselves vigorously against the lawsuit. The plaintiffs assert damages attributable to the remediation of the property of approximately $1.4 million. This case has been stayed pending the completion of remediation pursuant to the Louisiana Department of Environmental Quality ("LDEQ") requirements. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

In 1991, we were named as a defendant in a matter styled *Jimmy R. Green, et al. v. Cities Service Refinery, et al.* as filed in the 26th Judicial District Court of Bossier Parish, Louisiana. The plaintiffs in this matter reside or formerly resided on land that was once the site of a refinery owned by one of our co-defendants. The former refinery is located near our Bossier City facility. Plaintiffs have claimed personal injuries and property damage arising from alleged contamination of the refinery property. The plaintiffs have recently pursued certification as a class and have significantly increased their demand to approximately $175.0 million. 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 or its affiliates. The complaint names as defendants the General Partner; the Board of Directors of the General Partner; the parent companies of the General Partner, including EPCO; Enterprise and certain of its affiliates; and Dan L. Duncan. We are named as a nominal defendant.

The complaint alleges, among other things, that certain of the transactions proposed in the Proxy Statement, including a proposal to reduce the General Partner’s maximum percentage interest in our distributions in exchange for Units (the “Issuance Proposal”), are unfair to our unitholders and constitute 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 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 or its affiliates that are unfair to us or otherwise unfairly favored Enterprise or its affiliates over us. The complaint alleges that such transactions include the Jonah joint venture entered into by us and an Enterprise affiliate in August 2006 (citing the fact that our AC 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 affiliate of the Pioneer plant in March 2006 and the impending divestiture of our interest in MB Storage in connection with an investigation by the FTC. As more fully described in the Proxy Statement, the AC Committee recommended the Issuance Proposal for approval by the Board of Directors of the General Partner. The complaint also alleges that Richard S. Snell, Michael B. Bracy and Murray H. Hutchison, constituting the three members of the AC Committee, cannot be considered independent because of their alleged ownership of securities in Enterprise and its affiliates and their relationships with Mr. Duncan.

The complaint seeks relief (i) rescinding transactions in the complaint that have been consummated or awarding rescissory damages in respect thereof; (ii) awarding damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the complaint; and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts.

On September 22, 2006, the plaintiff in the action filed a motion to expedite the proceedings, requesting the Court to schedule a hearing on plaintiff’s motion for a preliminary injunction to enjoin the defendants from proceeding with the special meeting of unitholders. On September 26, 2006, the defendants advised the Court that we would provide to our unitholders specified supplemental disclosures, which were included in the Form 8-K and supplemental proxy materials we filed with the SEC on October 5, 2006. The special meeting was convened on December 8, 2006, at which our unitholders approved all of the proposals. In light of the foregoing, we believe that the plaintiff’s grounds for seeking relief by requiring us to issue a proxy statement that corrects the alleged misstatements and omissions in the Proxy Statement and enjoining the special meeting are moot. On November 17, 2006, the defendants (other than us, the nominal defendant) moved to dismiss the complaint. While we cannot predict the ultimate outcome, we do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

In addition to the 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 lawsuits and other proceedings will not individually or in the aggregate have a future material adverse effect on our consolidated financial position, results of operations or cash flows.

Regulatory Matters

Our 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 December 31, 2006 and 2005, we have an accrued liability of $1.8 million and $2.4 million, respectively, related to sites requiring environmental remediation activities.

In 1994, the LDEQ issued a compliance order for environmental contamination at our Arcadia, Louisiana, facility. In 1999, our Arcadia facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this contamination. Effective March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility. This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility. At December 31, 2006, we have an accrued liability of $0.1 million for remediation costs at our Arcadia facility. We do not expect that the completion of the remediation program proposed to the LDEQ will have a future material adverse effect on our financial position, results of operations or cash flows.

On July 27, 2004, we received notice from the United States Department of Justice (“DOJ”) of its intent to seek a civil penalty against us related to our November 21, 2001, release of approximately 2,575 barrels of jet fuel from our 14-inch diameter pipeline located in Orange County, Texas. The DOJ, at the request of the Environmental Protection Agency, is seeking a civil penalty against us for alleged violations of the Clean Water Act (“CWA”) arising out of this release, as well as three smaller spills at other locations in 2004 and 2005. We have agreed with the DOJ on a proposed penalty of $2.9 million, along with our commitment to implement additional spill prevention measures, and expect to finalize the settlement in the second quarter of 2007. We do not expect this settlement to have a material adverse effect on our financial position, results of operations or cash flows.

One of the spills encompassed in our current settlement discussion with the DOJ involved a 37,450-gallon release from Seaway on May 13, 2005 at Colbert, Oklahoma. This release was remediated under the supervision of the Oklahoma Corporation Commission, but resulted in claims by neighboring landowners that have been settled for approximately $0.7 million. In addition, the release resulted in a Corrective Action Order by the U.S. Department of Transportation. Among other requirements of this Order, we were required to reduce the operating pressure of Seaway by 20% until completion of required corrective actions. The corrective actions were completed and on June 1, 2006, we increased the operating pressure of Seaway back to 100%. We have a 50% ownership interest in Seaway, and any settlement should be covered by our insurance. We do not expect the completion of our obligations relating to the Colbert release to have a material adverse effect on our financial position, results of operations or cash flows.

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

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

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 FERC. In addition, pipelines may not confer any undue preference upon any shipper. Shippers may protest, and the FERC may investigate, the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months. It can also require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful. The FERC and interested parties can also challenge tariff rates that have become final and effective. Because of the complexity of rate making, the lawfulness of any rate is never assured. 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 services we provide are subject to various state laws and regulations that apply to the rates we charge and the terms and conditions of the services we offer. Although state regulation typically is less onerous than FERC regulation, the rates we charge and the provision of our services may be subject to challenge.

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

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2006. A description of each type of contractual obligation follows (in millions):

	Payment or Settlement due by Period						
	Total	2007	2008	2009	2010	2011	Thereafter
Maturities of long-term debt (1)	$1,580.0	$ —	$180.0	$ —	$ —	$490.0	$910.0
Operating leases (2)	69.7	18.7	11.7	8.8	7.3	6.3	16.9
Purchase obligations (3)	15.0	12.9	1.4	0.5	0.1	—	0.1
Capital expenditure obligations (4)	9.5	9.5	—	—	—	—	—

(1) We have long-term payment obligations under our Revolving Credit Facility and our Senior Notes. Amounts shown in the table represent our scheduled future maturities of long-term debt principal for the periods indicated (ee Note 13 for additional information regarding our consolidated debt obligations).

(2) We lease property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year for the periods indicated. 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 for the years ended December 31, 2006, 2005 and 2004, was $25.3 million, $24.0 million and $22.1 million, respectively.

(3) We have long and short-term purchase obligations for products and services with third-party suppliers. The prices that we are obligated to pay under these contracts approximate current market prices. The preceding table shows our commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for products and services at December 31, 2006.

(4) We have short-term payment obligations relating to capital projects we have initiated. These commitments represent unconditional payment obligations that we have agreed to pay vendors for services rendered or products purchased.

Other

Centennial entered into credit facilities totaling $150.0 million, and as of December 31, 2006, $150.0 million was outstanding under those credit facilities, of which $10.0 million matures in April 2007, and $140.0 million matures in April 2024. TE Products and Marathon Petroleum Company LLC (“Marathon”) have each guaranteed one-half of the repayment of Centennial’s outstanding debt balance (plus interest) under these credit facilities. The guarantees arose in order for Centennial to obtain adequate financing to fund construction and conversion costs of its pipeline system. Prior to the expiration of the long-term credit facility, TE Products could be relinquished from responsibility under the guarantee should Centennial meet certain financial tests. If Centennial defaults on its outstanding balance, the estimated maximum potential amount of future payments for TE Products and Marathon is $75.0 million each at December 31, 2006. As a result of the guarantee, TE Products recorded an obligation of $0.1 million, which represents the present value of the estimated amount we would have to pay under the guarantee.

TE Products, Marathon and Centennial have entered into a limited cash call agreement, which allows each member to contribute cash in lieu of Centennial procuring separate insurance in the event of a third-party liability arising from a catastrophic event. There is an indefinite term for the agreement and each member is to contribute cash in proportion to its ownership interest, up to a maximum of $50.0 million each. As a result of the catastrophic event guarantee, TE Products recorded a $4.4 million obligation, which represents the present value of the estimated amount that we would have to pay under the guarantee. If a catastrophic event were to occur and we were required to contribute cash to Centennial, contributions exceeding our deductible might be covered by our insurance, 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 equipment. We have guaranteed the full and timely payment and performance of TCO's obligations under the agreements. Generally, events of default would trigger our performance under the guarantee. The maximum potential amount of future payments under the guarantee is not estimable, but would include base rental payments for both current and future equipment, stipulated loss payments in the event any equipment is stolen, damaged, or destroyed and any future indemnity payments. We carry insurance coverage that may offset any payments required under the guarantees. 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.

On February 24, 2005, the General Partner was acquired from DEFS by DFI. The General Partner owns a 2% general partner interest in us and is the general partner of the Partnership. On March 11, 2005, the Bureau of Competition of the FTC delivered written notice to DFI's legal advisor that it was conducting a non-public investigation to determine whether DFI's acquisition of our General Partner may substantially lessen competition or violate other provisions of federal antitrust laws. We and our General Partner cooperated fully with this investigation.

On October 31, 2006, an FTC order and consent agreement ending its investigation became final. The order requires the divestiture of our 50% interest in MB Storage and certain related assets to one or more FTC-approved buyers in a manner approved by the FTC and subject to its final approval. Because we did not divest the interest and related assets by December 31, 2006, the order allows the FTC to appoint a divestiture trustee to oversee their sale to one or more approved buyers. The order contains no minimum price for the divestiture and requires that we provide the acquirer or acquirers the opportunity to hire employees who spend more than 10% of their time working on the divested assets. The order also imposes specified operational, reporting and consent requirements on us including, among other things, in the event that we acquire interests in or operate salt dome storage facilities for NGLs in specified areas. We have made application with the FTC to approve a buyer and sale terms for our interest in MB Storage and certain related pipelines, and we expect to close on such sale during the first quarter of 2007.

On December 19, 2006, we announced that we had signed an agreement with Motiva Enterprises, LLC ("Motiva") for us to construct and operate a new refined products storage facility to support the proposed expansion of Motiva's refinery in Port Arthur, Texas. Under the terms of the agreement, we will construct 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 3.5-mile product pipelines connecting the storage facility to Motiva's refinery, 15,000 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 in mid-2009. As a part of a separate but complementary initiative, we will construct 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. This associated project 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 $240.0 million, including $20.0 million for the 11-mile, 20-inch pipeline. By providing access to several major outbound refined product pipeline systems, shippers should have enhanced flexibility and new transportation options. 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. If the cancellation were to occur in 2007, Motiva would also pay costs incurred to date plus a five percent cancellation fee, with the fee increasing to ten percent after 2007.

Substantially all of the petroleum products that we transport and store are owned by our customers. At December 31, 2006, TCTM and TE Products had approximately 3.8 million barrels and 23.7 million barrels, respectively, of products in their custody that was owned by customers. We are obligated for the transportation, storage and delivery of such products on behalf of our customers. We maintain insurance adequate to cover product losses through circumstances beyond our control.

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

We also maintain excess liability insurance coverage above the established primary limits for commercial general liability and automobile liability insurance. Limits, terms, conditions and deductibles are commensurate with the nature and scope of our operations. The cost of our general insurance coverages has increased over the past year reflecting the changing conditions of the insurance markets. These insurance policies, except for the pollution liability policies, are through EPCO (see Note 16).

NOTE 19. CONCENTRATIONS OF CREDIT RISK

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

For the years ended December 31, 2006, 2005 and 2004, Valero Energy Corp. accounted for 14%, 14% and 16%, respectively, of our total consolidated revenues, and for the year ended December 31, 2006, BP Oil Supply Company accounted for 11% of our total consolidated revenues. No other single customer accounted for 10% or more of our total consolidated revenues for the years ended December 31, 2006, 2005 and 2004.

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NOTE 20. 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 activities and (iii) cash payments for interest for the years ended December 31, 2006, 2005 and 2004:

	For Year Ended December 31,		
	2006	2005	2004
Decrease (increase) in:			
Accounts receivable, trade	$ (67,317)	$ (249,745)	$ (181,690)
Accounts receivable, related parties	1,736	6,638	(14,693)
Inventories	(45,002)	(970)	(3,433)
Other current assets	25,552	(19,088)	(9,926)
Other	(9,906)	(4,371)	(9,163)
Increase (decrease) in:			
Accounts payable and accrued expenses	44,348	254,251	186,942
Accounts payable, related parties	15,696	(12,817)	4,360
Other	(6,135)	(11,252)	19,735
Net effect of changes in operating accounts	$ (41,028)	$ (37,354)	$ (7,868)
Non-cash investing activities:			
Net assets transferred to Mont Belvieu Storage Partners, L.P.	$ —	$ 1,429	$ —
Net assets transferred to Jonah Gas Gathering Company	$ 572,609	$ —	$ —
Payable to Enterprise Gas Processing, LLC for spending for Phase V expansion of Jonah Gas Gathering Company	$ 8,732	$ —	$ —
Supplemental disclosure of cash flows:			
Cash paid for interest (net of amounts capitalized)	$ 88,107	$ 82,315	$ 77,510

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

NOTE 21. SELECTED QUARTERLY DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2006:				
Operating revenues	$ 2,536,369	$ 2,425,052	$ 2,570,045	$ 2,076,019
Operating income	62,638	58,170	51,839	57,132
Income from continuing operations	43,383	41,586	41,145	56,568
Income from discontinued operations	19,491	(122)	—	—
Net income	62,874	41,464	41,145	56,568
Basic and diluted net income per Limited Partner Unit: (1)				
Continuing operations	$ 0.43	$ 0.42	$ 0.39	$ 0.53
Discontinued operations	0.19	—	—	—
Basic and diluted net income per Limited Partner Unit	$ 0.62	$ 0.42	$ 0.39	$ 0.53
2005:				
Operating revenues	$ 1,523,791	$ 2,087,385	$ 2,500,127	$ 2,493,731
Operating income	61,232	53,817	43,378	61,606
Income from continuing operations	46,305	40,076	28,883	44,137
Income from discontinued operations	1,124	846	692	488
Net income	47,429	40,922	29,575	44,625
Basic and diluted net income per Limited Partner Unit: (1) (2)				
Continuing operations	$ 0.53	$ 0.42	$ 0.29	$ 0.45
Discontinued operations	0.01	0.01	0.01	—
Basic and diluted net income per Limited Partner Unit	$ 0.54	$ 0.43	$ 0.30	$ 0.45

(1) Per Unit calculation includes 14,091,275 Units issued in December 2006 to our General Partner, 5,750,000 Units issued in July 2006 in an underwritten public offering and 6,965,000 Units issued in May and June 2005 in an underwritten public offering.

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

NOTE 22. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., and Val Verde Gas Gathering Company, L.P., have issued full, unconditional, and joint and several guarantees of our Senior Notes and our Revolving Credit Facility (collectively "the Guaranteed Debt"). In addition, during the 2005 periods presented below and extending through July 31, 2006, Jonah Gas Gathering Company also had provided the same guarantees of our Guaranteed Debt. Effective August 1, 2006, Enterprise, through its affiliate, Enterprise Gas Processing, LLC, became our joint venture partner by acquiring an interest in Jonah Gas Gathering Company (see Note 9). Jonah Gas Gathering Company was released as a guarantor of the Guaranteed Debt, effective upon the formation of the joint venture.

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

	December 31, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 37,534	$ 149,056	$ 894,916	$ (114,796)	$ 966,710
Property, plant and equipment – net	—	958,266	683,829	—	1,642,095
Equity investments	1,319,931	1,317,671	195,606	(1,793,498)	1,039,710
Intercompany notes receivable	1,215,132	—	—	(1,215,132)	—
Intangible assets	—	153,803	31,607	—	185,410
Other assets	5,769	21,657	60,741	—	88,167
Total assets	$ 2,578,366	$ 2,600,453	$ 1,866,699	$ (3,123,426)	$ 3,922,092
Liabilities and partners' capital					
Current liabilities	$ 40,578	$ 161,101	$ 889,665	$ (114,796)	$ 976,548
Long-term debt	1,215,948	387,339	—	—	1,603,287
Intercompany notes payable	—	711,381	503,751	(1,215,132)	—
Other long term liabilities	2,251	17,857	1,819	—	21,927
Total partners' capital	1,319,589	1,322,775	471,464	(1,793,498)	1,320,330
Total liabilities and partners' capital	$ 2,578,366	$ 2,600,453	$ 1,866,699	$ (3,123,426)	$ 3,922,092

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

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	For Year Ended December 31, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ —	$ 352,844	$ 9,263,451	$ (8,810)	$ 9,607,485
Costs and expenses	—	278,973	9,117,359	(11,222)	9,385,110
Gains on sales of assets	—	(1,415)	(5,989)	—	(7,404)
Operating income	—	75,286	152,081	2,412	229,779
Interest expense – net	—	(52,980)	(33,191)	—	(86,171)
Equity earnings	202,051	176,267	11,905	(353,462)	36,761
Other income – net	—	1,545	1,420	—	2,965
Income before deferred income tax expense	202,051	200,118	132,215	(351,050)	183,334
Deferred income tax expense	—	135	517	—	652
Income from continuing operations	202,051	199,983	131,698	(351,050)	182,682
Discontinued operations	—	—	19,369	—	19,369
Net income	$ 202,051	$ 199,983	$ 151,067	$ (351,050)	$ 202,051

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

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

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	For Year Ended December 31, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Cash flows from continuing operating activities					
Net income	$ 202,051	$ 202,051	$ 151,058	$ (353,109)	$ 202,051
Adjustments to reconcile net income to net cash from continuing operating activities:					
Income from discontinued operations	—	—	(19,369)	—	(19,369)
Deferred income tax expense	—	135	517	—	652
Depreciation and amortization	—	71,100	37,152	—	108,252
Earnings in equity investments, net of distributions	76,515	36,636	8,613	(95,042)	26,722
Gains on sales of assets	—	(5,599)	(1,805)	—	(7,404)
Changes in assets and liabilities and other	(75,103)	(47,167)	(28,143)	111,061	(39,352)
Net cash from continuing operating activities	203,463	257,156	148,023	(337,090)	271,552
Cash flows from discontinued operations	—	—	1,521	—	1,521
Net cash from operating activities	203,463	257,156	149,544	(337,090)	273,073
Cash flows from investing activities	(195,060)	48,236	(80,645)	(46,247)	(273,716)
Cash flows from financing activities	594	(305,392)	(68,936)	374,328	594
Net change in cash and cash equivalents	8,997	—	(37)	(9,009)	(49)
Cash and cash equivalents at January 1	1,978	—	107	(1,966)	119
Cash and cash equivalents at December 31	$ 10,975	$ —	$ 70	$ (10,975)	$ 70

	For Year Ended December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Cash flows from continuing operating activities					
Net income	$ 162,551	$ 162,551	$ 60,072	$ (222,623)	$ 162,551
Adjustments to reconcile net income to net cash from continuing operating activities:					
Income from discontinued operations	—	(3,150)	—	—	(3,150)
Depreciation and amortization	—	82,536	28,193	—	110,729
Earnings in equity investments, net of distributions	88,550	14,598	1,576	(87,733)	16,991
Gains on sales of assets	—	(551)	(117)	—	(668)
Changes in assets and liabilities and other	(54,540)	(57,645)	22,884	53,571	(35,730)
Net cash from continuing operating activities	196,561	198,339	112,608	(256,785)	250,723
Cash flows from discontinued operations	—	3,782	—	—	3,782
Net cash from operating activities	196,561	202,121	112,608	(256,785)	254,505
Cash flows from investing activities	(278,806)	(31,529)	(180,486)	139,906	(350,915)
Cash flows from financing activities	80,107	(184,126)	65,097	119,029	80,107
Net increase in cash and cash equivalents	(2,138)	(13,534)	(2,781)	2,150	(16,303)
Cash and cash equivalents at January 1	4,116	13,596	2,826	(4,116)	16,422
Cash and cash equivalents at December 31	$ 1,978	$ 62	$ 45	$ (1,966)	$ 119

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TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

NOTE 23. SUBSEQUENT EVENTS

On January 23, 2007, we sold a 10-mile, 18-inch segment of pipeline to an affiliate of Enterprise for approximately $8.0 million. 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.

On February 28, 2007, due to the substantial completion of inquires by the FTC into EPCO's acquisition of our General Partner, the parties to the ASA amended it to remove Exhibit B thereto, which had been adopted to address matters the parties anticipated the FTC may consider in its inquiry. Exhibit B had set forth certain separateness and screening policies and procedures among the parties that became inapposite upon the issuance of the FTC's order in connection with the inquiry or were already otherwise reflected in applicable FTC, SEC, NYSE or other laws, standards or governmental regulations. For further discussion of the FTC investigation, please see Note 18.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY
(A Wyoming General Partnership)

Consolidated Financial Statements
December 31, 2006

(With Report of Independent Registered Public Accounting Firm Thereon)

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of
Jonah Gas Gathering Company:

We have audited the accompanying consolidated balance sheet of Jonah Gas Gathering Company and Subsidiary (the “Partnership”) as of December 31, 2006, and the related statement of consolidated income, consolidated cash flows and consolidated partners’ capital for the year ended December 31, 2006. These consolidated financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Jonah Gas Gathering Company and subsidiary as of December 31, 2006, and the results of their operations and their cash flows for the year ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 28, 2007

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

CONSOLIDATED BALANCE SHEET
(Dollars in thousands)

	December 31, 2006
ASSETS	
Current assets:	
Cash and cash equivalents	$ —
Accounts receivable, trade	24,629
Accounts receivable, related parties	2,492
Inventories	1,319
Other	5,523
Total current assets	33,963
Property, plant and equipment, at cost (net of accumulated depreciation and amortization of $42,690)	633,459
Intangible assets	160,313
Goodwill	2,776
Other assets	4,043
Total assets	$ 834,554
LIABILITIES AND PARTNERS' CAPITAL	
Current liabilities:	
Accounts payable and accrued liabilities	$ 6,597
Accounts payable, related parties	185
Distribution payable	11,716
Other accrued taxes	1,160
Other	5,455
Total current liabilities	25,113
Other liabilities and deferred credits	191
Commitments and contingencies (Note 10)	
Partners' capital	809,250
Total liabilities and partners' capital	$ 834,554

See Notes to Consolidated Financial Statements.

JONAH GATHERING COMPANY AND SUBSIDIARY

STATEMENT OF CONSOLIDATED INCOME
(Dollars in thousands)

	For Year Ended December 31, 2006
Operating revenues:	
Gathering – Natural gas	$ 104,415
Sales of natural gas	50,866
Other	4,849
Total operating revenues	160,130
Costs and expenses:	
Purchases of natural gas	48,290
Operating expense	12,925
General and administrative	242
Depreciation and amortization	19,647
Taxes – other than income taxes	2,748
Total costs and expenses	83,852
Operating income	76,278
Other income (expense):	
Interest expense – net	(6,812)
Other income – net	198
Income from continuing operations	69,664
Income from discontinued operations	1,497
Gain on sale of discontinued operations	17,872
Discontinued operations	19,369
Net income	$ 89,033

See Notes to Consolidated Financial Statements.

JONAH GATHERING COMPANY AND SUBSIDIARY

STATEMENT OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For Year Ended December 31, 2006
Operating activities:	
Net income	$ 89,033
Adjustments to reconcile net income to cash provided by continuing operating activities:	
Income from discontinued operations	(19,369)
Depreciation and amortization	19,647
Non-cash portion of interest expense	174
Net effect of changes in operating accounts:	
Increase in accounts receivable, trade	(6,232)
Increase in accounts receivable, related parties	(2,492)
Decrease in inventories	254
Decrease in other current assets	13,675
Decrease in accounts payable and accrued expenses	(3,202)
Increase in accounts payable, related parties	30,113
Other	(712)
Net cash provided by continuing operating activities	120,889
Net cash provided by discontinued operations	1,521
Net cash provided by operating activities	122,410
Investing activities:	
Proceeds from the sales of assets	38,000
Capital expenditures	(51,211)
Net cash used in investing activities	(13,211)
Financing activities:	
Proceeds from Note Payable, TEPPCO Midstream Companies, L.P.	66,375
Repayments of Note Payable, TEPPCO Midstream Companies, L.P.	(96,990)
Contributions from partners	20,000
Distributions paid to partners	(98,646)
Net cash used in financing activities	(109,261)
Net decrease in cash and cash equivalents	(62)
Cash and cash equivalents, January 1	62
Cash and cash equivalents, December 31	$ —
Non-cash financing activities:	
Non-cash contributions from partners for Phase V expansion	$ 243,718
Distributions payable to partners	11,716
Contribution of Note Payable, TEPPCO Midstream Companies, L.P. to partners’ capital	231,220
Contribution of accrued interest to partners’ capital	19,900
Contribution of accounts payable, related party to partners’ capital	20,876
Supplemental disclosure of cash flows:	
Cash paid for interest (net of amounts capitalized)	$ 6,188

See Notes to Consolidated Financial Statements.

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JONAH GATHERING COMPANY AND SUBSIDIARY

STATEMENT OF CONSOLIDATED PARTNERS' CAPITAL
(Dollars in thousands)

	TEPPCO GP, Inc.	TEPPCO Midstream Companies, L.P.	Enterprise Gas Processing, LLC	Total
Balance, December 31, 2005	$ 3	$ 294,862	$ —	$ 294,865
Net income	1	88,794	238	89,033
Contributions	—	418,840	116,874	535,714
Distributions	—	(110,162)	(200)	(110,362)
Transfer of partnership interest	(4)	4	—	—
Balance, December 31, 2006	$ —	$ 692,338	$ 116,912	$ 809,250

See Notes to Consolidated Financial Statements.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization

Jonah Gas Gathering Company ("Jonah"), a Wyoming general partnership, owns a 643 mile natural gas gathering system known as the "Jonah Gas Gathering System" in the Green River Basin of southwestern Wyoming. Jonah has life of lease agreements with natural gas producers in the Jonah and Pinedale fields to provide gathering services to the producers. As used in these financial statements, "we," "us," or "Jonah" are intended to mean Jonah Gas Gathering Company and, where the context requires, include our subsidiary.

The Jonah Gas Gathering System was originally constructed in 1992. Prior to June 1, 2000, Jonah was a subsidiary of McMurry Oil Company. On June 1, 2000, in connection with Alberta Energy Company's ("AEC") purchase of McMurry Oil Company, AEC acquired all of the outstanding partnership interests in Jonah for cash consideration and the assumption of debt, for an aggregate cost of approximately $208.0 million.

On September 30, 2001, TEPPCO Partners, L.P. ("TEPPCO"), a publicly traded Delaware limited partnership, through it affiliates, TEPPCO GP, Inc. ("TEPPCO GP") and TEPPCO Midstream Companies, L.P. ("TEPPCO Midstream"), purchased Jonah from AEC for $360.0 million. TEPPCO Midstream is owned 99.999% by TEPPCO and 0.001% by TEPPCO GP as its general partner. TEPPCO GP is wholly owned by TEPPCO. TEPPCO Midstream owned a 99.999% interest in Jonah and TEPPCO GP owned a 0.001% interest in Jonah. Duke Energy Field Services, LLC ("DEFS") managed and operated the Jonah assets for TEPPCO under a contractual agreement. TEPPCO's general partner was an indirect wholly owned subsidiary of DEFS, a joint venture between Duke Energy Corporation and ConocoPhillips.

On February 24, 2005, TEPPCO's general partner was acquired by DFI GP Holdings L.P., an affiliate of EPCO, Inc. ("EPCO"), a privately held company controlled by Dan L. Duncan. Mr. Duncan and his affiliates, including EPCO, Dan Duncan LLC and privately held companies controlled by him, control TEPPCO and its general partner. In conjunction with an amended and restated administrative services agreement, EPCO performs all management, administrative and operating functions required for TEPPCO, including us, and TEPPCO reimburses EPCO for all direct and indirect expenses that have been incurred in its management. TEPPCO assumed the operations of Jonah from DEFS, and certain employees of DEFS became employees of EPCO effective June 1, 2005. On August 18, 2005, TEPPCO formed Jonah Gas Marketing, LLC ("JGM") a Delaware limited liability company, to conduct marketing activities for Jonah. TEPPCO Midstream was the sole member of JGM.

Since TEPPCO's acquisition of Jonah in 2001, the pipeline capacity and processing capacity of the Jonah system has been expanded as follows:

- The Phase I expansion was completed in May 2002, at a cost of approximately $25.0 million and increased system capacity by 62%, from approximately 450 million cubic feet per day ("MMcf/d") to approximately 730 MMcf/d.
- In October 2002, the Phase II expansion project was completed at a cost of approximately $35.3 million, which increased the capacity of the Jonah system from 730 MMcf/d to approximately 880 MMcf/d.
- In 2003, the Jonah system was again expanded by the Phase III project to include an 80-mile pipeline loop and 3,700 horsepower of new compression on the system and the building of a new 300 MMcf/d gas processing plant near Opal, Wyoming. Phase III was substantially completed during the fourth quarter of 2003, with system capacity increasing to 1,180 MMcf/d at a cost of approximately $53.4 million. This gas processing plant was sold to Enterprise Products Partners L.P. on March 31, 2006 (see Note 7).
- Additional capacity of 100 MMcf/d was completed during the fourth quarter of 2004, at a cost of approximately $13.0 million.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

- The Phase IV expansion project was completed in February 2006, at a cost of approximately $116.0 million and increased system capacity to 1.5 billion cubic feet per day ("Bcf/d") with the addition of 33,000 horsepower of compression and approximately 50 miles of pipeline.

Formation of Joint Venture

In order to fund further expansion of the Jonah system, on August 1, 2006, TEPPCO GP and TEPPCO Midstream entered into an Amended and Restated Partnership Agreement of Jonah Gas Gathering Company (the "Partnership Agreement") with Enterprise Gas Processing, LLC ("EGP"), an affiliate of Enterprise Products Partners L.P. ("Enterprise Products"). Enterprise Products is a publicly traded Delaware limited partnership, and an affiliate of DFI GP Holdings L.P., which is the sole member of TEPPCO's general partner. Under the Partnership Agreement, EGP was admitted as a new partner in exchange for funding a portion of the costs related to an expansion of the Jonah system. On August 1, 2006, in connection with the admission of EGP into the Jonah partnership, TEPPCO Midstream acquired the Jonah partnership interest previously owned by TEPPCO GP and contributed all of its interest in JGM to Jonah. Effective August 1, 2006, Jonah owns all of the outstanding membership interests in JGM, and TEPPCO Midstream holds all of the partnership interest in Jonah that was previously held by TEPPCO GP.

Through the joint venture with EGP, a Phase V expansion project is expected to increase the system capacity of the Jonah system from 1.5 Bcf/d to approximately 2.3 Bcf/d and to significantly reduce system operating pressures. The expansion project is segmented into two parts. The first part of the expansion, which is expected to increase the system gathering capacity to approximately 2.0 Bcf/d, is scheduled to be completed in the second quarter of 2007. The pipeline looping portion of the first part of the expansion, which included the addition of 75 miles of 36-inch diameter pipe and 12 miles of 24-inch diameter pipe, was completed in December 2006. The second part of the expansion is expected to be completed by the end of 2007. The anticipated cost of the Phase V expansion will be approximately $444.0 million.

Jonah is governed by a management committee comprised of two representatives approved by Enterprise Products and two representatives approved by TEPPCO, each with equal voting power. EGP is the operator of the Jonah assets. Based upon a formula in the partnership agreement that takes into account the capital contributions of the parties to fund the Phase V expansion project discussed below, as well as certain capital expenditures made by TEPPCO not related to the expansion project, TEPPCO expects to own an interest in Jonah of approximately 80%, with EGP owning the remaining 20%.

Under a letter of intent TEPPCO entered into in February 2006, Enterprise Products assumed the management of the Phase V expansion project and funded the initial costs of the expansion. Beginning with the August 1, 2006 formation of the Jonah joint venture, TEPPCO reimbursed Enterprise Products for 50% of the expansion costs it had previously advanced, and TEPPCO and Enterprise began sharing the costs of the expansion equally. TEPPCO is expected to reimburse Enterprise Products for approximately 50% of the Phase V expansion costs. To the extent the costs exceed an agreed upon base cost estimate of $415.2 million, TEPPCO and Enterprise will each pay their respective ownership share (approximately 80% and 20%, respectively) of such costs.

In that regard, TEPPCO and Enterprise Products have been working with producers to finalize the scope and design of the Phase V expansion to optimally serve the expected production needs in both the Jonah and Pinedale fields. However, the overall high level of activity in the greater Green River Basin area has strained locally available resources, which, coupled with rising steel costs, is likely to cause the final cost of the expansion to exceed the original agreed upon estimate.

TEPPCO received all distributions from the joint venture until a specified milestone in the Phase V expansion was achieved in November of 2006, at which point, EGP became entitled to receive approximately 50%

of the incremental revenue from certain portions of the expansion project already placed in service. Upon completion of the next specified milestone, EGP will begin to share in revenues of the joint venture based upon the total amount of its capital contributions until, as discussed above, final ownership in the joint venture will be approximately 80% TEPPCO and 20% EGP.

Note 2. Summary of Significant Accounting Policies

Accounts Receivable and Allowance for Doubtful Accounts

Our customers primarily consist of companies within the petroleum industry. We perform ongoing credit evaluations of our customers and generally do not require material collateral. A provision for losses on accounts receivable is established if it is determined that we will not collect all or part of the outstanding balance. Collectibility is reviewed regularly, and an allowance is established or adjusted, as necessary, using the specific identification method. As of December 31, 2006, we had no provision for doubtful accounts.

Asset Retirement Obligations

Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*, ("SFAS 143") including related interpretations such as Financial Accounting Standards Board Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* ("FIN 47") addresses financial accounting and reporting associated with the retirement of tangible long-lived assets and related asset retirement costs. It requires entities to record the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. When the liability is recorded, the entity capitalizes the costs of the liability by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. SFAS 143 applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development, and normal operation of a long-lived asset (see Note 6).

Basis of Presentation and Principles of Consolidation

The financial statements include our accounts on a consolidated basis. We have eliminated all significant intercompany items in consolidation. Our results for the year ended December 31, 2006 reflect the operations and activities of our Pioneer plant as discontinued operations.

Cash and Cash Equivalents

Cash equivalents are defined as highly marketable investments with maturities of three months or less when purchased. The carrying value of these cash equivalents approximate fair value because of the short-term nature of these investments. Our Statement of Consolidated Cash Flows is prepared using the indirect method.

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Our management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our legal counsel evaluates the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss if determinable and material, is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. At December 31, 2006, we had no liabilities for loss contingencies.

Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States ("GAAP") requires our management to make estimates and assumptions that affect 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 these estimates.

Fair Value of Current Assets and Current Liabilities

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

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired. Goodwill amounts are assessed for impairment (i) on an annual basis during the fourth quarter of each year or (ii) on an interim basis when impairment indicators are present. If such indicators are present (e.g., loss of a significant customer, economic obsolescence of plant assets, etc.), the fair value of the reporting unit to which the goodwill is assigned will be calculated and compared to its book value.

If the fair value of the reporting unit exceeds its book value, the goodwill amount is not considered to be impaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value, a charge to earnings is recorded to adjust the carrying value of the goodwill to its implied fair value. We have not recognized any impairment losses related to our goodwill for the period presented.

Income Taxes

We are a general partnership. As such, we are not a taxable entity for federal and state income tax purposes and do not directly pay federal and state income tax. Our taxable income or loss, which may vary substantially from the net income or net loss reported in the net income or net loss reported in our statement of income, is includable in the federal and state income tax returns of each partner. Accordingly, no recognition has been given to federal or state income taxes for our operations.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Intangible Assets

Intangible assets consist of gathering contracts that dedicate future production from natural gas wells in the Green River Basin in Wyoming. The value assigned to these intangible assets relates to contracts with customers that are for either a fixed term or which dedicate total future lease production to the gathering system. These intangible assets are amortized on a unit-of-production basis, based upon the actual throughput of the system over the expected total throughput for the lives of the contracts. Revisions to the unit-of-production estimates may occur as additional production information is made available to us (see Note 4).

Natural Gas Imbalances

Gas imbalances occur when gas producers (customers) deliver more or less actual natural gas volumes to our gathering system than they originally nominated. Actual deliveries are different from nominated volumes due to fluctuations in gas production at the wellhead. If the customers supply more natural gas volumes than they nominated, Jonah records a payable for the amount due to customers and also records a receivable for the same amount due from connecting pipeline transporters or shippers. If the customers supply less natural gas volumes than they nominated, Jonah records a receivable reflecting the amount due from customers and a payable for the same amount due to connecting pipeline transporters or shippers. We record these natural gas imbalances using a mark-to-market approach.

Operating, General and Administrative Expenses

EPCO allocates operating, general and administrative expenses to us for administrative, management, engineering and operating services based upon the estimated level of effort devoted to our various operations. We believe that the method for allocating corporate operating, general and administrative expenses is reasonable. Unless noted otherwise, our agreements with TEPPCO and EPCO are not the result of arm’s length transactions. As a result, we cannot provide assurance that the terms and provisions of such agreements are at least as favorable to us as we could have obtained from unaffiliated third parties.

Property, Plant and Equipment

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

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

Revenue Recognition

Gathering revenues are recognized as natural gas is received from the customer. We generally do not take title to the natural gas, except for the wellhead sale and purchase of natural gas to facilitate system operations and to provide a service to some of the producers on the system. The Jonah system sells condensate liquid from the natural gas stream based on a contracted price based generally on an index based crude oil price less a differential. In May 2006, we began to aggregate purchases of wellhead gas on Jonah and re-sell the aggregate quantities at key Jonah delivery points in order to facilitate operational needs and throughput on Jonah. The purchases and sales are generally contracted to occur in the same month to minimize price risk. Revenues associated with condensate sales are recognized when the product is sold.

Note 3. Recently Issued Accounting Standards

In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R) (revised 2004), *Share-Based Payment*. SFAS 123(R) is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*, as amended by SFAS No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure* and supersedes Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees*. SFAS 123(R) requires that the cost resulting from all share-based payment transactions be recognized in the financial statements at fair value. SFAS 123(R) became effective for public companies for annual periods beginning after June 15, 2005. Accordingly, we adopted SFAS 123(R) in the first quarter of 2006. We adopted SFAS 123(R) under the modified prospective transition method. The adoption of SFAS 123(R) did not have a material effect on our financial position, results of operations or cash flows.

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

In September 2005, the EITF reached consensus in EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, to define when a purchase and a sale of inventory with the same party that operates in the same line of business should be considered a single nonmonetary transaction subject to APB Opinion No. 29, *Accounting for Nonmonetary Transactions*. Two or more inventory transactions with the same party should be combined if they are entered into in contemplation of one another. The EITF also requires entities to account for exchanges of inventory in the same line of business at fair value or recorded amounts based on inventory classification. The guidance in EITF 04-13 is effective for new inventory arrangements entered into in reporting periods beginning after March 15, 2006. We adopted EITF 04-13 on April 1, 2006. The adoption of EITF 04-13 did not have a material effect on our financial position, results of operations or cash flows.

In June 2006, the EITF reached consensus in EITF 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)*. The accounting guidance permits companies to elect to present on either a gross or net basis sales and other taxes that are imposed on and concurrent with individual revenue-producing transactions between a seller and a customer. The gross basis includes the taxes in revenues and costs; the net basis excludes the taxes from revenues. The accounting guidance does not apply to tax systems that are based on gross receipts or total revenues. EITF 06-3 requires companies to disclose their policy for presenting the taxes and disclose any amounts presented on a gross basis if those amounts are significant. The guidance in EITF 06-3 is effective January 1, 2007. As a matter of policy, we report such taxes on a net basis. The adoption of EITF 06-3 did not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS 157 applies only to fair-value measurements that are already required or permitted by other accounting standards and is expected to increase the consistency of those measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies will be required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop the measurements, and the effect of certain of the measurements on earnings (or changes in net assets) for the period. SFAS 157 is effective for fiscal years beginning after December 15, 2007, and we are required to adopt SFAS 157 as of January 1, 2008. We believe that the adoption of SFAS 157 will not have a material effect on our financial position, results of operations and cash flows.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* ("SAB 108"). SAB 108 addresses how the effects of prior-year uncorrected misstatements should be considered when quantifying misstatements in current-year financial statements. The SAB requires registrants to quantify misstatements using both balance-sheet and income-statement approaches and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is determined to be material, SAB 108 allows registrants to record that effect as a cumulative-effect adjustment to beginning-of-year retained earnings. The requirements are effective for annual financial statements covering the first fiscal year ending after November 15, 2006. Additionally, the nature and amount of each individual error being corrected through the cumulative-effect adjustment, when and how each error arose, and the fact that the errors had previously been considered immaterial is required to be disclosed. We are required to adopt SAB 108 for our current fiscal year ending December 31, 2006. The adoption of SAB 108 did not have a material effect on our financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities - Including an amendment of FASB Statement No. 115*. SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between the different measurement attributes the company elects for similar types of assets and liabilities. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact of the adoption of SFAS 159 on our financial statements. We do not believe the adoption of SFAS 159 will have a material effect on our financial position, results of operations or cash flows.

Note 4. Goodwill and Intangible Assets

Goodwill

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

To perform an impairment test of goodwill, we determined we have one reporting unit. We determine the carrying value and the fair value of the reporting unit and compare them. We will continue to compare the fair value of the reporting unit to its carrying value on an annual basis to determine if an impairment loss has occurred. There have been no goodwill impairment losses recorded since the adoption of SFAS 142. At December 31, 2006, the recorded value of goodwill was $2.8 million.

Other Intangible Assets

At December 31, 2006, we had intangible assets (natural gas gathering contracts) with a gross carrying amount of $222.8 million and accumulated amortization of $62.5 million. SFAS 142 requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. Amortization expense on intangible assets was $9.8 million for the year ended December 31, 2006.

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

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

2007	$12,748
2008	15,020
2009	16,621
2010	16,122
2011	13,865

Note 5. Related Party Transactions

We have no employees. As a result of the change in ownership of TEPPCO's general partner on February 24, 2005, EPCO assumed the management of us on June 1, 2005. Beginning June 1, 2005, in conjunction with an amended and restated administrative services agreement (see Note 1), EPCO performs all management, administrative and operating functions required for us and we reimburse EPCO for all direct and indirect expenses that have been incurred in our management. The expenses associated with these management and operations services are reflected in costs and expenses in the accompanying statements of income.

We sell natural gas relating to our natural gas marketing activities to our partners and their affiliates. We also sell condensate liquid from the natural gas stream of the Jonah gas gathering system to our partners and their affiliates.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Revenues and expenses from TEPPCO and EPCO and their respective affiliates consist of the following (in thousands):

	For Year Ended December 31, 2006
Revenues from TEPPCO and affiliates:	
Sales of natural gas liquids ("NGLs")(1)	$ 3,764
Other operating revenues (2)	4,622
Revenues and Purchases from EPCO and affiliates:	
Sales of natural gas	$ 8,585
Purchases of natural gas (3)	251
Gain on sale of Pioneer plant	17,872
Operating expense (4)	6,149

(1) Includes NGL sales to TEPPCO Crude Oil, L.P. ("TCO") from our Pioneer processing plant prior to the sale of the plant to an affiliate of Enterprise Products. These sales are classified as income from discontinued operations in the accompanying consolidated financial statements.

(2) Includes condensate sales to TCO.

(3) Includes processing fees paid to Enterprise Products for processing services performed at the Pioneer processing plant after the sale of the plant to an affiliate of Enterprise Products.

(4) Includes payroll, payroll related expenses, administrative expenses, including reimbursements related to employee benefits and employee benefit plans, and other operating expenses incurred in managing us and our subsidiary.

Our related party accounts receivable and related party accounts payable that are included on the balance sheet consist of the following (in thousands):

	December 31, 2006		
	Accounts Receivable	Accounts Payable	Other Current Liabilities (1)
Partners:			
TEPPCO	$ 879	$ —	$ —
Enterprise Products and affiliates	1,613	185	643
Total	$ 2,492	$ 185	$ 643

(1) Relates to pipeline imbalances with an affiliate of EPCO.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note 6. Property, Plant and Equipment

The components of property, plant and equipment at December 31, 2006 were as follows (in thousands):

	December 31, 2006
Land and right of way	$ 20,893
Line pipe and fittings	295,482
Storage tanks	5,718
Buildings and improvements	3,239
Machinery and equipment	74,396
Construction work in progress	276,421
Total property, plant and equipment	$ 676,149
Less accumulated depreciation and amortization	42,690
Net property, plant and equipment	$ 633,459

Depreciation expense on property, plant and equipment was $9.8 million for the year ended December 31, 2006.

We regularly review our long-lived assets for impairment in accordance with SFAS 144. We have identified no long-lived assets that would require impairment as of December 31, 2006.

Asset Retirement Obligation

We have recorded a $0.2 million liability, which represents the fair value of conditional asset retirement obligation related to the retirement of the natural gas gathering system. During the third quarter of 2006, we assigned probabilities for settlement dates and settlement methods for use in an expected present value measurement of fair value and recorded an asset retirement obligation. The following table presents information regarding our asset retirement obligation (in thousands):

Liabilities recorded	$ 186
Liabilities settled	—
Accretion	5
Revision in estimates	—
Asset retirement obligation liability balance, December 31, 2006	$ 191

Property, plant and equipment at December 31, 2006, includes $0.1 million of asset retirement costs capitalized as an increase in the associated long-lived asset. Additionally, based on information currently available, we estimate that accretion expense will approximate $19 thousand for 2007, $21 thousand for 2008, $23 thousand for 2009, $25 thousand for 2010 and $28 thousand for 2011.

Note 7. Dispositions and Discontinued Operations

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

A condensed statement of income for the Pioneer plant, which is classified as discontinued operations, for the year ended December 31, 2006 is presented below (in thousands):

	For Year Ended December 31, 2006
Operating revenues:	
Sales of NGLs	$ 3,828
Other	932
Total operating revenues	4,760
Costs and expenses:	
Purchases of petroleum products	3,000
Operating expense	182
Depreciation and amortization	51
Taxes – other than income taxes	30
Total costs and expenses	3,263
Income from discontinued operations	$ 1,497

Cash flows from discontinued operations for the year ended December 31, 2006 is presented below (in thousands):

	For Year Ended December 31, 2006
Cash flows from discontinued operating activities:	
Net income	$ 19,369
Depreciation and amortization	51
Gain on sale of Pioneer plant	(17,872)
Increase in inventories	(27)
Net cash flows from discontinued operations	$ 1,521

Note 8. Debt Obligations

Prior to August 1, 2006, we utilized debt financing available from TEPPCO through intercompany notes. The terms of the intercompany notes generally matched the principal and interest payment dates under TEPPCO's credit agreement and senior notes. The interest rates charged by TEPPCO included its stated interest rate, plus a premium to cover debt issuance costs. The interest rate was also decreased or increased to cover gains and losses, respectively, on any interest rate swaps that TEPPCO had in place on its credit agreement and senior notes. TEPPCO's senior notes and revolving credit facility are described below.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

On June 27, 2003, TEPPCO entered into a $550.0 million unsecured revolving credit facility with a three-year term, including the issuance of letters of credit of up to $20.0 million ("Revolving Credit Facility"). The interest rate is based, at TEPPCO's option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. The credit agreement for the Revolving Credit Facility contains certain restrictive financial covenant ratios. Restrictive covenants in the Revolving Credit Facility limit TEPPCO's and its subsidiaries' ability to, among other things, incur additional indebtedness, make distributions in excess of Available Cash and complete mergers, acquisitions and sales of assets. On October 21, 2004, TEPPCO amended the Revolving Credit Facility to (i) increase the facility size to $600.0 million, (ii) extend the term to October 21, 2009, (iii) remove certain restrictive covenants, (iv) increase the available amount for the issuance of letters of credit up to $100.0 million and (v) decrease the LIBOR rate spread charged at the time of each borrowing. On December 13, 2005, TEPPCO amended its Revolving Credit Facility as follows:

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

At December 31, 2006, TEPPCO had $490.0 million outstanding under its Revolving Credit Facility at a weighted average interest rate of 5.96%. At December 31, 2006, TEPPCO was in compliance with the covenants of this credit agreement.

Note Payable, TEPPCO Midstream

Effective August 1, 2006, in connection with the formation of the joint venture with Enterprise Products, amounts outstanding of $231.2 million under the intercompany notes payable to TEPPCO Midstream were converted to capital contributions and reclassified as partners' capital. For the period from January 1, 2006 through July 31, 2006, interest costs incurred on the note payable to TEPPCO Midstream totaled $8.4 million.

Note 9. Partners' Capital and Distributions

Prior to August 1, 2006, we made 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 TEPPCO in its sole discretion. We paid distributions of 99.999% to TEPPCO Midstream and 0.001% to TEPPCO GP.

Effective August 1, 2006, in connection with the formation of the joint venture between TEPPCO and EGP, our partnership agreement was amended. We paid distributions 100% to TEPPCO until specified milestones were met in the Phase V expansion in November 2006. At that point, EGP became entitled to receive approximately 50% of the incremental cash flow from certain portions of the expansion project already placed in service. Upon completion of the next specified milestone, EGP will begin to share in the revenues of the joint venture based upon the total amount of its capital contributions until, as discussed in Note 1, final ownership in the joint venture will be approximately 80% TEPPCO and 20% EGP.

For the year ended December 31, 2006, cash distributions paid to TEPPCO Midstream totaled $98.6 million. At December 31, 2006, we have a distribution payable of $11.5 million and $0.2 million to TEPPCO Midstream and EGP, respectively.

For the year ended December 31, 2006, we received contributions of $418.8 million and $116.9 million from TEPPCO Midstream and EGP, respectively. The contribution amounts include $243.7 million of non-cash contributions from TEPPCO Midstream and EGP related to the Phase V expansion. The contribution from TEPPCO Midstream includes $231.2 million related to the transfer of the note payable with TEPPCO Midstream to partners' capital and $19.9 million for the related accrued interest, which occurred upon formation of the joint venture with EGP on August 1, 2006. Additionally, on August 1, 2006, the balance in our accounts payable, related parties of $20.9 million was transferred to partners' capital as non-cash contributions.

Note 10. Commitments and Contingencies

The Company is involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, management believes these claims will not have a material effect on the financial position, results of operations or cash flows.

Contractual Obligations

We use leased assets in several areas of our operations. Total rental expense for the year ended December 31, 2006, was $1.0 million. The following table sets forth our minimum rental payments under our various operating leases for the years ending December 31 (in thousands):

2007	$ 830
2008	87
2009	82
	$ 999

We have short-term payment obligations relating to capital projects we have initiated. These commitments represent unconditional payment obligations that we or our unconsolidated affiliates have agreed to pay vendors for services rendered or products purchased. At December 31, 2006, we had $0.2 million of short-term capital expenditure obligations.

Note 11. Employee Benefits

We were charged for employee benefits costs related to the TEPPCO Retirement Cash Balance Plan ("EPPCO RCBP") which was a noncontributory, trustee-administered pension plan, and TEPPCO's plans for healthcare and life insurance benefits for retired employees, which were on a contributory and noncontributory basis. Costs were allocated to us based on the level of effort provided by employees. 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. For those plan participants who elected to receive an annuity, TEPPCO purchased an annuity contract from an insurance company in which the plan participant owns the annuity, absolving TEPPCO of any future obligation to the participant. EPCO maintains a 401(k) plan for the benefit of employees providing services to us, and we reimburse EPCO for the cost of maintaining this plan.

INDEX TO EXHIBITS

3.1	Certificate of Limited Partnership of TEPPCO Partners, L.P. (Filed as Exhibit 3.2 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
3.2	Third Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P., dated September 21, 2001 (Filed as Exhibit 3.7 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
3.3	Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated March 31, 2000 (Filed as Exhibit 3.3 to Form 10-Q/A of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
3.4	Amendment to Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated March 22, 2005 (Filed as Exhibit 3.4 to Form 10-Q/A of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
3.5	Amendment to Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated June 15, 2006, but effective as of February 24, 2005 (Filed as Exhibit 3.1 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on June 16, 2006.
3.6	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).
4.1	Form of Certificate representing Limited Partner Units (Filed as Exhibit 4.1 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
4.2	Form of Indenture between TE Products Pipeline Company, Limited Partnership and The Bank of New York, as Trustee, dated as of January 27, 1998 (Filed as Exhibit 4.3 to TE Products Pipeline Company, Limited Partnership's Registration Statement on Form S-3 (Commission File No. 333-38473) and incorporated herein by reference).

4.3	Form of Certificate representing Class B Units (Filed as Exhibit 4.3 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1998 and incorporated herein by reference).
4.4	Form of Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.2 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.5	First Supplemental Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.3 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.6	Second Supplemental Indenture, dated as of June 27, 2002, among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, and Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as trustee (Filed as Exhibit 4.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
4.7	Third Supplemental Indenture among TEPPCO Partners, L.P. as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as trustee, dated as of January 30, 2003 (Filed as Exhibit 4.7 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
4.8	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).
10.1+	Duke Energy Corporation Executive Savings Plan (Filed as Exhibit 10.7 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
0.2+	Duke Energy Corporation Executive Cash Balance Plan (Filed as Exhibit 10.8 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.3+	Duke Energy Corporation Retirement Benefit Equalization Plan (Filed as Exhibit 10.9 to Form 10-K for TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.4+	Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan executed on March 8, 1994 (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1994 and incorporated herein by reference).
10.5+	Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan, Amendment 1, effective January 16, 1995 (Filed as Exhibit 10.12 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 1999 and incorporated herein by reference).
10.6+	Form of Employment Agreement between the Company and Thomas R. Harper, Charles H. Leonard, James C. Ruth, John N. Goodpasture, Leonard W. Mallett, Stephen W. Russell, C. Bruce Shaffer, and Barbara A. Carroll (Filed as Exhibit 10.20 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1998 and incorporated herein by reference).

10.7	Services and Transportation Agreement between TE Products Pipeline Company, Limited Partnership and Fina Oil and Chemical Company, BASF Corporation and BASF Fina Petrochemical Limited Partnership, dated February 9, 1999 (Filed as Exhibit 10.22 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1999 and incorporated herein by reference).
10.8	Call Option Agreement, dated February 9, 1999 (Filed as Exhibit 10.23 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1999 and incorporated herein by reference).
10.9+	Form of Employment and Non-Compete Agreement between the Company and J. Michael Cockrell effective January 1, 1999 (Filed as Exhibit 10.29 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.10+	Texas Eastern Products Pipeline Company Non-employee Directors Unit Accumulation Plan, effective April 1, 1999 (Filed as Exhibit 10.30 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.11+	Texas Eastern Products Pipeline Company Non-employee Directors Deferred Compensation Plan, effective November 1, 1999 (Filed as Exhibit 10.31 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.12+	Texas Eastern Products Pipeline Company Phantom Unit Retention Plan, effective August 25, 1999 (Filed as Exhibit 10.32 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.13+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan, Amendment and Restatement, effective January 1, 2000 (Filed as Exhibit 10.28 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2000 and incorporated herein by reference).
10.14+	TEPPCO Supplemental Benefit Plan, effective April 1, 2000 (Filed as Exhibit 10.29 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2000 and incorporated herein by reference).
10.15+	Employment Agreement with Barry R. Pearl (Filed as Exhibit 10.30 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2001 and incorporated herein by reference).
10.16	Second Amended and Restated Agreement of Limited Partnership of TE Products Pipeline Company, Limited Partnership, dated September 21, 2001 (Filed as Exhibit 3.8 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
10.17	Amended and Restated Agreement of Limited Partnership of TCTM, L.P., dated September 21, 2001 (Filed as Exhibit 3.9 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
10.18	Contribution, Assignment and Amendment Agreement among TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., Texas Eastern Products Pipeline Company, LLC, and TEPPCO GP, Inc., dated July 26, 2001 (Filed as Exhibit 3.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2001 and incorporated herein by reference).
10.19	Certificate of Formation of TEPPCO Colorado, LLC (Filed as Exhibit 3.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1998 and incorporated herein by reference).
10.20	Agreement of Limited Partnership of TEPPCO Midstream Companies, L.P., dated September 24, 2001 (Filed as Exhibit 3.10 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
10.21	Agreement of Partnership of Jonah Gas Gathering Company dated June 20, 1996 as amended by that certain Assignment of Partnership Interests dated September 28, 2001 (Filed as Exhibit 10.40 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2001 and incorporated herein by reference).

10.22	Unanimous Written Consent of the Board of Directors of TEPPCO GP, Inc. dated February 13, 2002 (Filed as Exhibit 10.41 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2001 and incorporated herein by reference).
10.23	Amended and Restated Credit Agreement among TEPPCO Partners, L.P. as Borrower, SunTrust Bank, as Administrative Agent and LC Issuing Bank and Certain Lenders, as Lenders dated as of March 28, 2002 ($500,000,000 Revolving Facility) (Filed as Exhibit 10.45 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2002 and incorporated herein by reference).
10.24	Purchase and Sale Agreement between Burlington Resources Gathering Inc. as Seller and TEPPCO Partners, L.P., as Buyer, dated May 24, 2002 (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of July 2, 2002 and incorporated herein by reference).
10.25	Amendment, dated as of June 27, 2002 to the Amended and Restated Credit Agreement among TEPPCO Partners, L.P., as Borrower, SunTrust Bank, as Administrative Agent, and Certain Lenders, dated as of March 28, 2002 ($500,000,000 Revolving Credit Facility) (Filed as Exhibit 99.3 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of July 2, 2002 and incorporated herein by reference).
10.26	Agreement of Limited Partnership of Val Verde Gas Gathering Company, L.P., dated May 29, 2002 (Filed as Exhibit 10.48 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
10.27+	Texas Eastern Products Pipeline Company, LLC 2002 Phantom Unit Retention Plan, effective June 1, 2002 (Filed as Exhibit 10.49 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
10.28+	Amended and Restated TEPPCO Supplemental Benefit Plan, effective November 1, 2002 (Filed as Exhibit 10.44 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.29+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan, Second Amendment and Restatement, effective January 1, 2003 (Filed as Exhibit 10.45 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.30+	Amended and Restated Texas Eastern Products Pipeline Company, LLC Management Incentive Compensation Plan, effective January 1, 2003 (Filed as Exhibit 10.46 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.31+	Amended and Restated TEPPCO Retirement Cash Balance Plan, effective January 1, 2002 (Filed as Exhibit 10.47 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.32	Formation Agreement between Panhandle Eastern Pipe Line Company and Marathon Ashland Petroleum LLC and TE Products Pipeline Company, Limited Partnership, dated as of August 10, 2000 (Filed as Exhibit 10.48 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.33	Amended and Restated Limited Liability Company Agreement of Centennial Pipeline LLC dated as of August 10, 2000 (Filed as Exhibit 10.49 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.34	Guaranty Agreement, dated as of September 27, 2002, between TE Products Pipeline Company, Limited Partnership and Marathon Ashland Petroleum LLC for Note Agreements of Centennial Pipeline LLC (Filed as Exhibit 10.50 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).

10.35	LLC Membership Interest Purchase Agreement By and Between CMS Panhandle Holdings, LLC, As Seller and Marathon Ashland Petroleum LLC and TE Products Pipeline Company, Limited Partnership, Severally as Buyers, dated February 10, 2003 (Filed as Exhibit 10.51 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.36	Joint Development Agreement between TE Products Pipeline Company, Limited Partnership and Louis Dreyfus Plastics Corporation dated February 10, 2000 (Filed as Exhibit 10.52 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2003 and incorporated herein by reference).
10.37	Credit Agreement among TEPPCO Partners, L.P. as Borrower, SunTrust Bank as Administrative Agent and LC Issuing Bank and The Lenders Party Hereto, as Lenders, dated as of June 27, 2003 ($550,000,000 Revolving Facility) (Filed as Exhibit 10.52 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2003 and incorporated herein by reference).
10.38	Agreement of Limited Partnership of Mont Belvieu Storage Partners, L.P. dated effective January 21, 2003 (Filed as Exhibit 10.53 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2003 and incorporated herein by reference).
10.39	Letter of Agreement Clarifying Rights and Obligations of the Parties Under the Mont Belvieu Storage Partners, L.P., Partnership Agreement and the Mont Belvieu Venture, LLC, LLC Agreement, dated October 25, 2003 (Filed as Exhibit 10.54 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2003 and incorporated herein by reference).
10.40	Amended and Restated Credit Agreement among TEPPCO Partners, L.P., as Borrower, SunTrust Bank, as Administrative Agent and LC Issuing Bank and The Lenders Party Hereto, as Lenders dated as of October 21, 2004 ($600,000,000 Revolving Facility) (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of October 21, 2004 and incorporated herein by reference).
10.41+	Texas Eastern Products Pipeline Company Amended and Restated Non-employee Directors Deferred Compensation Plan, effective April 1, 2002 (Filed as Exhibit 10.42 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2004 and incorporated herein by reference).
10.42+	Texas Eastern Products Pipeline Company Second Amended and Restated Non-employee Directors Unit Accumulation Plan, effective January 1, 2004 (Filed as Exhibit 10.41 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2004 and incorporated herein by reference).
10.43	First Amendment to Amended and Restated Credit Agreement, dated as of February 23, 2005, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A. and KeyBank, N.A. as Co-Documentation Agents (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 24, 2005 and incorporated herein by reference).
10.44+	Supplemental Agreement to Employment Agreement between the Company and Barry R. Pearl dated as of February 23, 2005 (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).
10.45+	Supplemental Agreement to Employment and Non-Compete Agreement between the Company and J. Michael Cockrell dated as of February 23, 2005 (Filed as Exhibit 10.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).
10.46+	Supplemental Form Agreement to Form of Employment Agreement between the Company and John N. Goodpasture, Stephen W. Russell, C. Bruce Shaffer and Barbara A. Carroll dated as of February 23, 2005 (Filed as Exhibit 10.3 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).

10.47+	Supplemental Form Agreement to Form of Employment and Agreement between the Company and Thomas R. Harper, Charles H. Leonard, James C. Ruth and Leonard W. Mallett dated as of February 23, 2005 (Filed as Exhibit 10.4 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).
10.48+	Amendments to the TEPPCO Retirement Cash Balance Plan and the TEPPCO Supplemental Benefit Plan dated as of May 27, 2005 (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, 2005 and incorporated herein by reference).
10.49+	Agreement and Release between Charles H. Leonard and Texas Eastern Products Pipeline Company, LLC dated as of July 11, 2005 (Filed as Exhibit 10.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
10.50	Third Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated August 15, 2005, but effective as of February 24, 2005 (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated August 19, 2005 and incorporated herein by reference).
10.51	Second Amendment to Amended and Restated Credit Agreement, dated as of December 13, 2005, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A. and KeyBank, N.A., as Co-Documentation Agents (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of December 13, 2005 and incorporated herein by reference).
10.52+	Agreement and Release between Barry R. Pearl and Texas Eastern Products Pipeline Company, LLC dated as of December 30, 2005 (Filed as Exhibit 10.52 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2005 and incorporated herein by reference).
10.53+	Agreement and Release between James C. Ruth and Texas Eastern Products Pipeline Company, LLC dated as of January 25, 2006 (Filed as Exhibit 10.53 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2005 and incorporated herein by reference).
10.54	Letter of Intent between TEPPCO Partners, L.P. and Enterprise Products Operating, L.P. dated February 13, 2006 (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated February 17, 2006 and incorporated herein by reference).
10.55+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan Notice of 2006 Award (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, 2006 and incorporated herein by reference).
10.56+	Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan Notice of 2006 Award (Filed as Exhibit 10.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2006 and incorporated herein by reference).
10.57	Third Amendment to Amended and Restated Credit Agreement, dated as of July 31, 2006, by and among TEPPCO Partners, L.P., the Borrower, several banks and other

	financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders and as the LC Issuing Bank, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A., and The Royal Bank of Scotland Plc, as Co-Documentation Agents (Filed as Exhibit 10.3 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.58	Amended and Restated Partnership Agreement of Jonah Gas Gathering Company dated as of August 1, 2006 (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.59	Contribution Agreement among TEPPCO GP, Inc., TEPPCO Midstream Companies, L.P. and Enterprise Gas Processing, LLC dated as of August 1, 2006 (Filed as Exhibit 10.2 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.60	Transaction Agreement by and between TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC dated as of September 5, 2006 (Filed as Exhibit 10 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed September 12, 2006 and incorporated herein by reference).
10.61	Fourth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., Duncan Energy Partners L.P., DEP Holdings, LLC, DEP Operating Partnership, L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated January 30, 2007, but effective as of February 5, 2007 (Filed as Exhibit 10.18 to Current Report on Form 8-K of Duncan Energy Partners L.P. (Commission File No. 1-33266) filed February 5, 2007 and incorporated herein by reference).
10.62+*	Form of Supplemental Agreement to Employment Agreement between Texas Eastern Products Pipeline Company, LLC and assumed by EPCO, Inc., and John N. Goodpasture, Samuel N. Brown and J. Michael Cockrell.
10.63+*	Form of Retention Agreement.
10.64*	Amended and Restated Agreement of Limited Partnership of TEPPCO Midstream Companies, L.P. by and between TEPPCO GP, Inc. and TEPPCO Partners, L.P. dated as of February 27, 2007.
10.65*	Second Amended and Restated Agreement of Limited Partnership of TCTM, L.P. by and between TEPPCO GP, Inc. and TEPPCO Partners, L.P. dated as of February 27, 2007.
10.66*	Third Amended and Restated Agreement of Limited Partnership of TE Products Pipeline Company, Limited Partnership by and between TEPPCO GP, Inc. and TEPPCO Partners, L.P. dated as of February 27, 2007.
10.67	First Amendment to the Fourth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., Duncan Energy Partners L.P., DEP Holdings, LLC, DEP Operating Partnership, L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated February 28, 2007 (Filed as Exhibit 10.8 to Form 10-K of Enterprise Products Partners L.P. (Commission File No. 1-14323) for the year ended December 31, 2006 and incorporated herein by reference).
12.1*	Statement of Computation of Ratio of Earnings to Fixed Charges.
16	Letter from KPMG LLP to the Securities and Exchange Commission dated April 11, 2006 (Filed as Exhibit 16.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed April 11, 2006 and incorporated herein by reference).
21*	Subsidiaries of TEPPCO Partners, L.P.

23.1*	Consent of Deloitte & Touche LLP.
23.2*	Consent of KPMG LLP.
24*	Powers of Attorney.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

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

\+ A management contract or compensation plan or arrangement.

Exhibit 10.62

FORM

SUPPLEMENTAL AGREEMENT {No. 2/No. 3}
To
EMPLOYMENT {AND NON-COMPETE} AGREEMENT

This Supplemental Agreement {No. 2/No.3} supplements and amends that certain Employment {and Non-Compete} Agreement entered into the ____________________, by and between Texas Eastern Products Pipeline Company and assumed by EPCO, Inc. ("EPCO"), and ____________________ ("Executive"), as amended ____________________ (as previously amended, the "Agreement").

In consideration of the mutual covenants contained herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, EPCO and Executive agree to amend the Agreement as follows:

1. Section 3 of the Agreement is hereby amended by adding the following thereto:

   "(d) If this Agreement has not previously terminated then on June 1, 2008, this Agreement shall automatically terminate and be of no further force or effect without any action required by either party."

2. Section 5 of the Agreement is hereby deleted in its entirety and the following shall be substituted in lieu thereof:

   "Intentionally Omitted"

3. { Section 8 of the Agreement is hereby deleted in its entirety and the following shall be substituted in lieu thereof:

   "Intentionally Omitted"}

4. {Section 9/Section11} of the Agreement is hereby deleted in its entirety and the following shall be substituted in lieu thereof:

   "Intentionally Omitted"

5. The Agreement is hereby amended by adding the following Section thereto:

“{Section 18/Section 20}. Current Award and Retention Award.

(a) Payment of Current Award. Within thirty (30) days from the execution of the Supplemental Agreement {No. 2/No.3} by the last of EPCO and Executive as evidenced by the dates below their respective signatures, EPCO shall pay to Executive the gross amount of $__________ (less applicable legally required deductions and other deductions elected by Executive).

(b) Payment of Retention Award. Provided Executive shall have remained as an employee of EPCO from the Effective Date until June 1, 2008, without interruption, EPCO shall pay to Executive, on or before July 1, 2008, the gross amount of $__________ (said $__________, less applicable legally required deductions and other deductions elected by Executive, being hereinafter referred to as the “Retention Award “). In the event Executive’s employment is terminated by EPCO prior to June 1, 2008 pursuant to Subsection {8/10}(a) (i), (ii) or (iv) of the Agreement, Subsection 1(a)(1)(iii) or Subsection 1(a)(2)(iii) of the Supplemental Agreement, then EPCO shall be required to pay to Executive the entire sum of the Retention Award within sixty (60) days of the date of the termination of Executive’s employment with EPCO.

(c) COBRA Continuation Coverage Cost. In addition, if Executive is enrolled in any of EPCO’s Medical or Dental Plan Coverages for Executive and his eligible dependants as an active employee at the time of such termination and Executive is terminated by EPCO prior to June 1, 2008 pursuant to Subsection {8/10} (a) (i), (ii) or (iv) of the Agreement, Subsection 1(a)(1)(iii) or Subsection 1(a)(2)(iii) of the Supplemental Agreement, then EPCO shall credit Executive with a lump sum in an amount that will provide an after- tax sum (assuming for this purpose that Executive is in the highest marginal tax bracket) equal to the current monthly COBRA continuation coverage cost of Executive’s coverage(s) (including Executive’s eligible dependants) at the time such amount is credited (including, where applicable, an HMO option, but excluding any Cafeteria Plan - Medical Spending Account) for thirty-six (36) consecutive months from the date of EPCO’s said termination of Executive’s employment. EPCO will promptly remit the income taxes due on such amount directly to the appropriate taxing authority. Should Executive obtain subsequent employment and become eligible for medical and/or dental coverages available to employees of the new employer, during such thirty-six (36) consecutive month period, Executive shall immediately so notify EPCO which shall immediately terminate Executive’s coverage(s) in its Medical and/or Dental Plans, as appropriate. Executive shall have no further right to any amounts that otherwise would have been applied to pay the monthly COBRA continuation coverage cost of medical and/or continuation coverage as provided hereunder.

(d) Termination or Resignation by Executive. In the event that prior to June 1, 2008: (i) Executive’s termination of employment by EPCO for cause pursuant to Subsection {8/10} (a)(iii) of this Agreement, or (ii) Executive’s voluntary resignation for any reason from his employment by EPCO, or (iii) Executive's retirement from his employment by EPCO, then in any of those events Executive shall not be entitled to all or any portion of the Retention Award or any amounts applied to pay the monthly COBRA continuation coverage cost of medical and/or continuation coverage as provided in Section {18/20} (c) hereof, and Executive shall have no further rights or entitlements with respect to the Retention Award".

6. Except as hereby amended by this SUPPLEMENTAL AGREEMENT {No. 2/No. 3}, the EMPLOYMENT AGREEMENT is hereby ratified and affirmed in all respects.

IN WITNESS WHEREOF, the persons hereto have executed this SUPPLEMENTAL AGREEMENT {No. 2/No. 3} effective for all purpose as of January 1, 2007 ("Effective Date").

EPCO, Inc.

By: ______________________________
Title: Thomas M. Zulim
Senior Vice President – Human Resources

Date: ____________________

EXECUTIVE:

____
Printed Name: ______________________________
Date: ______________________________

Exhibit 10.63

FORM OF RETENTION AGREEMENT

Because you are an important part of the management and professional team of Texas Eastern Products Pipeline Company, LLC (“Company”), the general partner of TEPPCO Partners, L.P. (the “Partnership”), it has been determined that it is in the best interests of the Partnership and its unit holders to offer you appropriate incentives to continue to focus on the business of the Partnership during the shared-service integration process between the EPCO, Inc. (“EPCO”) family of entities and the Company. Only those employees who are selected shall be eligible to participate in this retention program.

The retention program is implemented through individualized agreements entered into between EPCO and each participant which becomes effective with respect to a participant immediately upon such participant and an appropriate officer of EPCO executing same.

This Retention Agreement (“Agreement”) is made and entered into effective __________, 2006, (“Effective Date”) between EPCO and __________ (“Employee”).

WHEREAS, EPCO desires to enter into this Agreement with Employee to provide a method for providing retention payment to encourage continued high performance and to encourage Employee to remain employed through the shared-service integration process.

NOW, THEREFORE, in consideration thereof and of the covenants hereafter set forth, the parties hereby agree as follows:

Provided Employee shall have remained as an active fulltime employee of EPCO from the Effective Date through December 31, 2007 without interruption, EPCO shall pay to Employee in cash, on or before January 31, 2008, a gross amount equal to the product of the amount of Employee’s base annual salary on December 31, 2007 times __________%, less applicable withholding (“Retention Payment”).

In addition, Employee must maintain a satisfactory level of performance during the retention period to be eligible for the Retention Payment. In the event Employee is involuntarily terminated due to poor performance, no Retention Payment shall be made to Employee. Employee is not eligible for a Retention Payment if Employee voluntarily terminates employment, is terminated for ‘cause’ or retires on or before December 31, 2007.

Employee understands that the terms of this Agreement are confidential and Employee shall not disclose either the existence of this Agreement nor the terms hereof. Should Employee violate the confidentiality provisions of this Agreement, Employee shall not be eligible for the Retention Payment.

EPCO, Inc.

By: ______________________		______________________
Name: ______________________		Employee:
Title: ______________________		

Exhibit 10.64

AMENDED AND RESTATED
AGREEMENT OF LIMITED PARTNERSHIP OF
TEPPCO MIDSTREAM COMPANIES, L.P.

THIS AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP OF TEPPCO MIDSTREAM COMPANIES, L.P., dated as of February 27, 2007 is entered into by and between TEPPCO GP, Inc., a Delaware corporation, as the General Partner (as defined below) and TEPPCO Partners, L.P., a Delaware limited partnership ("TEPPCO"), as the Limited Partner (as defined below).

WHEREAS, the General Partner and the Limited Partner entered into the Agreement of Limited Partnership of TEPPCO Midstream Companies, L.P. dated as of September 24, 2001 (the "Previous Partnership Agreement");

WHEREAS, on December 8, 2006, the agreement of limited partnership of TEPPCO, which is the Limited Partner and the sole stockholder of the General Partner, was amended and restated, among other things, to delete therefrom provisions requiring approval of the unitholders of TEPPCO to amend the partnership agreement of the Partnership under specified circumstances, such provisions serving no meaningful purpose once the General Partner became a wholly-owned subsidiary of TEPPCO; and

WHEREAS, the General Partner and the Limited Partner desire to amend and restate the Previous Partnership Agreement in its entirety to make such changes as they have deemed appropriate in light of matters described in the foregoing recitals;

NOW, THEREFORE, in consideration of the covenants, conditions and agreements contained herein, the General Partner and the Limited Partner do hereby amend and restate the Previous Partnership Agreement in its entirety as follows:

ARTICLE I
DEFINITIONS

The following definitions shall for all purposes, unless otherwise clearly indicated to the contrary, apply to the terms used in this Agreement.

"Affiliate" means, with respect to any Person, any other Person that directly or indirectly controls, is controlled by or is under common control with, the Person in question. As used herein, the term "control" means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a Person, whether through ownership of voting securities, by contract or otherwise.

"Certificate of Limited Partnership" means the Certificate of Limited Partnership filed with the Secretary of State of the State of Delaware as referenced in Section 2.5, as such Certificate may be amended and/or restated from time to time.

"Code" means the Internal Revenue Code of 1986, as amended and in effect from time to time, as interpreted by the applicable regulations thereunder. Any reference herein to a specific section or sections of the Code shall be deemed to include a reference to any corresponding provision of future law.

"Delaware Act" means the Delaware Revised Uniform Limited Partnership Act, 6 Del. C. Section 17-101 *et seq*., as amended, supplemented or restated from time to time, and any successor to such statute.

"General Partner" means TEPPCO GP, Inc., a Delaware corporation, in its capacity as the general partner of the Partnership, and any successor to TEPPCO GP, Inc., as general partner.

"Indemnitee" has the meaning given such term in Section 10.1(a).

"Limited Partner" means TEPPCO, in its capacity as the limited partner of the Partnership, and any other limited partner admitted to the Partnership from time to time and that is shown as a limited partner on the books and records of the Partnership.

"Partner" means the General Partner or the Limited Partner.

"Partnership" means TEPPCO Midstream Companies, L.P., a Delaware limited partnership.

"Partnership Interest" means the interest of a Partner in the Partnership.

"Percentage Interest" means, as of the date of such determination, (a) 0.001% as to the General Partner and (b) 99.999% as to the Limited Partner.

"Person" means an individual or a corporation, partnership, limited liability company, trust, unincorproated organization, association or other entity.

"Previous Partnership Agreement" has the meaning given such term in the recitals.

"Subsidiary" means a Person controlled by the Partnership directly, or indirectly through one or more intermediaries.

"TEPPCO" means TEPPCO Partners, L.P., a Delaware limited partnership.

ARTICLE II
ORGANIZATIONAL MATTERS

Section 2.1 *Continuation*. The General Partner and the Limited Partner hereby continue this Partnership as a limited partnership pursuant to the provisions of the Delaware Act. This amendment and restatement shall become effective on the date of this Agreement. Except as expressly provided to the contrary in this Agreement, the rights, duties (including fiduciary duties), liabilities and obligations of the Partners and the administration, dissolution and termination of the Partnership shall be governed by the Delaware Act. The Partnership Interest of each Partner shall be personal property for all purposes.

Section 2.2 *Name*. The name of the Partnership shall be "TEPPCO Midstream Companies, L.P." The Partnership's business may be conducted under any other name or names deemed necessary or appropriate by the General Partner, including, without limitation, the name of the General Partner or any Affiliate thereof. The words "Limited Partnership," "L.P.," "Ltd." or similar words or letters shall be included in the Partnership's name where necessary for the purposes of complying with the laws of any jurisdiction that so requires. The General Partner in its sole discretion may change the name of the Partnership at any time and from time to time.

Section 2.3 *Registered Office; Principal Office*. Unless and until changed by the General Partner, the registered office of the Partnership in the State of Delaware shall be located at The Corporation Trust Center, 1209 Orange Street, New Castle County, Wilmington, Delaware 19801 and the registered agent for service of process on the Partnership in the State of Delaware at such registered office shall be The Corporation Trust Company. The principal office of the Partnership and the address of the General Partner shall be 1100 Louisiana Street, Houston, Texas 77002, or such other place as the General Partner may from time to time designate. The Partnership may maintain offices at such other place or places within or outside the State of Delaware as the General Partner deems advisable.

Section 2.4 *Term*. The Partnership commenced upon the filing of the Certificate of Limited Partnership in accordance with the Delaware Act and shall continue in existence until the close of Partnership business on December 31, 2084, or until the earlier termination of the Partnership in accordance with the provisions of this Agreement. The existence of the Partnership as a separate legal entity shall continue until the cancellation of the Certificate of Limited Partnership as provided in the Delaware Act.

Section 2.5 *Certificate of Limited Partnership*. The General Partner has caused the Certificate of Limited Partnership to be filed with the Secretary of State of the State of Delaware as required by the Delaware Act and shall use all reasonable efforts to cause to be filed such other certificates or documents as may be determined by the General Partner in its sole discretion to be reasonable and necessary or appropriate for the formation, continuation, qualification and operation of a limited partnership (or a partnership in which the limited partners have limited liability) in the State of Delaware or any other state in which the Partnership may elect to do business or own property. To the extent that such action is determined by the General Partner in its sole discretion to be reasonable and necessary or appropriate, the General Partner shall file amendments to and restatements of the Certificate of Limited Partnership and do all things to maintain the Partnership as a limited partnership (or a partnership in which the limited partners have limited liability) under the laws of the State of Delaware or of any other state in which the Partnership may elect to do business or own property.

ARTICLE III
PURPOSE

Section 3.1 *Purpose and Business*. The purpose and nature of the business to be conducted by the Partnership shall be (a) to engage in the gathering of natural gas and natural gas liquids and related products and related activities, (b) to engage directly in, or to enter into or form any corporation, partnership, joint venture, limited liability company or similar arrangement to engage in, any business activity that may be lawfully conducted by a limited partnership organized pursuant to the Delaware Act and, in connection therewith, to exercise all of the rights and powers conferred upon the Partnership pursuant to the agreements relating to such business activity, (c) to do anything necessary or appropriate to the foregoing (including, without limitation, the making of capital contributions or loans to any Subsidiary or in connection with its involvement in the activities referred to in clause (b) of this sentence), and (d) to engage in any other business activity as permitted under Delaware law.

Section 3.2 *Powers*. The Partnership shall be empowered to do any and all acts and things necessary, appropriate, proper, advisable, incidental to or convenient for the furtherance and accomplishment of the purposes and business described in Section 3.1 and for the protection and benefit of the Partnership.

ARTICLE IV
CAPITAL CONTRIBUTIONS

Section 4.1 *Prior Contributions*. Prior to the date hereof, the Limited Partner and the General Partner, or their predecessors, have made capital contributions to the Partnership.

Section 4.2 *Additional Contributions*. A Partner may contribute additional cash or property to the capital of the Partnership, but no Partner has any obligation pursuant to this Agreement to make any such contribution.

Section 4.3 *Return of Contributions; Other Provisions Relating to Contributions.* No Partner shall be entitled to withdraw any part of its capital contributions or its capital account or to receive any distribution from the Partnership, except as provided in this Agreement. An unrepaid capital contribution is not a liability of the Partnership or any Partner, and no interest shall accrue on capital contributions or on balances in Partners' capital accounts.

Section 4.4 *Loans* A Partner may make secured or unsecured loans to the Partnership, but no Partner has any obligation pursuant to this Agreement to make any such loan. Loans by a Partner to the Partnership shall not be considered capital contributions.

ARTICLE V
CAPITAL ACCOUNTS; ALLOCATIONS; DISTRIBUTIONS

Section 5.1 *Capital Accounts*. The Partnership shall maintain for each Partner a separate capital account in accordance with the regulations issued pursuant to Section 704 of the Code and as determined by the General Partner as consistent therewith.

Section 5.2 *Allocations for Tax and Capital Account Purposes*. For federal income tax purposes, each item of income, gain, loss, deduction and credit of the Partnership shall be allocated among the Partners in accordance with their Percentage Interests, except that the General Partner shall have the authority to make such other allocations as are necessary and appropriate to comply with Section 704 of the Code and the regulations issued pursuant thereto.

Section 5.3 *Distributions*. The Partnership shall make distributions to the Partners at such times, and in such forms and amounts, as the General Partner may from time to time determine. Distributions in liquidation of the Partnership shall be made in accordance with the positive balances in the Partners' respective capital accounts maintained pursuant to Section 5.1. All other distributions shall be made to the Partners in accordance with their respective Percentage Interests.

ARTICLE VI
MANAGEMENT AND OPERATIONS OF BUSINESS

The General Partner shall conduct, direct and exercise full control over all activities of the Partnership. Except as otherwise expressly provided in this Agreement, all management powers over the business and affairs of the Partnership shall be exclusively vested in the General Partner. In addition to the powers now or hereafter granted a general partner of a limited partnership under applicable law or which are granted to the General Partner under any other provision of this Agreement, the General Partner shall have full power and authority to do all things and on such terms as it, in its sole discretion, may deem necessary or desirable to conduct the business of the Partnership, to exercise all powers set forth in Section 3.2 and to effectuate the purposes set forth in Section 3.1.

ARTICLE VII
RIGHTS AND OBLIGATIONS OF LIMITED PARTNER

The Limited Partner shall have no liability under this Agreement except as expressly provided in this Agreement or the Delaware Act. The Limited Partner shall not take part in the operation, management or control (within the meaning of the Delaware Act) of the Partnership's business, transact any business in the Partnership's name or have the power to sign documents for or otherwise bind the Partnership. The transaction of any such business by the General Partner, any of its Affiliates or any officer, director, employee, partner, agent or trustee of the General Partner or any of its Affiliates, in its capacity as such, shall not affect, impair or eliminate the limitations on the liability of the Limited Partner under this Agreement.

ARTICLE VIII
DISSOLUTION AND LIQUIDATION

The Partnership shall dissolve, and its affairs shall be wound up, upon (a) the expiration of its term as provided in Section 2.4, (b) the occurrence of an event of withdrawal of the General Partner under the Delaware Act, (c) an election to dissolve the Partnership by the General Partner that is approved by the Limited Partner, (d) entry of a decree of judicial dissolution of the Partnership pursuant to the provisions of the Delaware Act, (e) the sale of all or substantially all of the assets and properties of the Partnership and its Subsidiaries, taken as a whole or (f) the dissolution of TEPPCO, if such dissolution occurs while TEPPCO is a Partner; *provided*, *however*, that the Partnership shall not be dissolved or required to be wound up by reason of any event of withdrawal of the General Partner described in the preceding clause (b), if (i) at the time of such event of withdrawal, there is at least one other general partner of the Partnership who carries on the business of the Partnership (any remaining or successor general partner being hereby authorized to carry on the business of the Partnership) or (ii) within 90 days after the withdrawal, the Limited Partner agrees in writing or votes to continue the business of the Partnership and to the appointment, effective as of the date of withdrawal, of one or more general partners of the Partnership.

ARTICLE IX
AMENDMENT OF PARTNERSHIP AGREEMENT

The General Partner may amend any provision of this Agreement without the consent of the Limited Partner and may execute, swear to, acknowledge, deliver, file and record whatever documents may be required in connection therewith, except that any amendment that would increase the liability of the Limited Partner or materially and adversely affect the rights of the Limited Partner under this Agreement requires the consent of the Limited Partner.

ARTICLE X
INDEMNIFICATION

Section 10.1 *Indemnification*.

(a) To the fullest extent permitted by law but subject to the limitations expressly provided in this Agreement, the General Partner, the Limited Partner and any Person who is or was an officer or director of the General Partner (each, an "Indemnitee") shall each be indemnified and held harmless by the Partnership from and against any and all losses, claims, damages, liabilities (joint or several), expenses (including, without limitation, legal fees and expenses), judgments, fines, penalties, interest, settlements and other amounts arising from any and all claims, demands, actions, suits or proceedings, whether civil, criminal, administrative or investigative, in which any Indemnitee may be involved, or is threatened to be involved, as a party or otherwise, by reason of its status as an Indemnitee; *provided*, that the Indemnitee shall not be indemnified and held harmless if there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which the Indemnitee is seeking indemnification pursuant to this Section 10.1, the Indemnitee acted in bad faith or engaged in fraud, willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was unlawful. Any indemnification pursuant to this Section 10.1 shall be made only out of the assets of the Partnership, it being agreed that the General Partner shall not be personally liable for such indemnification and shall have no obligation to contribute or loan any monies or property to the Partnership to enable it to effectuate such indemnification.

(b) To the fullest extent permitted by law, expenses (including, without limitation, legal fees and expenses) incurred by an Indemnitee in defending any claim, demand, action, suit or proceeding shall, from time to time, be advanced by the Partnership prior to the final disposition of such claim, demand, action, suit or proceeding upon receipt by the Partnership of an undertaking by or on behalf of the Indemnitee to repay such amount if it shall be determined that the Indemnitee is not entitled to be indemnified as authorized in this Section 10.1.

(c) The indemnification provided by this Section 10.1 shall be in addition to any other rights to which an Indemnitee may be entitled under any agreement, as a matter of law or otherwise, both as to actions in the Indemnitee's capacity as an Indemnitee and as to actions in any other capacity, and shall continue as to an Indemnitee who has ceased to serve in such capacity.

(d) The Partnership may purchase and maintain (or reimburse the General Partner or its Affiliates for the cost of) insurance, on behalf of the General Partner and such other Persons as the General Partner shall determine, against any liability that may be asserted against or expense that may be incurred by such Person in connection with the Partnership's activities, whether or not the Partnership would have the power to indemnify such Person against such liabilities under the provisions of this Agreement.

(e) In no event shall the Limited Partner be subjected to personal liability by reason of the indemnification provisions set forth in this Agreement, whether by action of an Indemnitee or otherwise.

(f) An Indemnitee shall not be denied indemnification in whole or in part under this Section 10.1 because the Indemnitee had an interest in the transaction with respect to which the indemnification applies if the transaction was otherwise permitted by the terms of this Agreement.

(g) The provisions of this Section 10.1 are for the benefit of the Indemnitees, their heirs, successors and assigns and shall not be deemed to create any rights for the benefit of any other Persons.

(h) No amendment, modification or repeal of this Section 10.1 or any provision hereof shall in any manner terminate, reduce or impair the right of any past, present or future Indemnitee to be indemnified by the Partnership, nor the obligation of the Partnership to indemnify any such Indemnitee under and in accordance with the provisions of this Section 10.1 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.

(i) THE PROVISIONS OF THE INDEMNIFICATION PROVIDED IN THIS SECTION 10.1 ARE INTENDED BY THE PARTIES TO APPLY EVEN IF SUCH PROVISIONS HAVE THE EFFECT OF EXCULPATING THE INDEMNITEE FROM LEGAL RESPONSIBILITY FOR THE CONSEQUENCES OF SUCH PERSON'S NEGLIGENCE, FAULT OR OTHER CONDUCT.

Section 10.2 *Liability of Indemnitees*.

(a) Notwithstanding anything to the contrary set forth in this Agreement, no Indemnitee shall be liable for monetary damages to the Partnership or any Partner for losses sustained or liabilities incurred as a result of any act or omission of an Indemnitee unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter in question, the Indemnitee acted in bad faith or engaged in fraud, willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was criminal.

(b) Subject to its obligations and duties as General Partner set forth in Article VI, the General Partner may exercise any of the powers granted to it by this Agreement and perform any of the duties imposed upon it hereunder either directly or by or through its agents, and the General Partner shall not be responsible for any misconduct or negligence on the part of any such agent appointed by the General Partner in good faith.

(c) Any amendment, modification or repeal of this Section 10.2 or any provision hereof shall be prospective only and shall not in any way affect the limitations on the liability of an Indemnitee under this Section 10.2 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.

ARTICLE XI
BOOKS AND RECORDS

The General Partner shall keep or cause to be kept at the principal office of the Partnership appropriate books and records with respect to the Partnership's business including, without limitation, all books and records necessary to provide to the Limited Partner any information, lists, and copies of documents required to be provided pursuant to the Delaware Act. Any such records may be maintained in other than a written form if such form is capable of conversion into a written form within a reasonable time.

ARTICLE XII
GENERAL PROVISIONS

Section 12.1 *Addresses and Notices*. Any notice, demand, request or report required or permitted to be given or made to a Partner under this Agreement shall be in writing and shall be deemed given or made if received by it at the principal office of the Partnership referred to in Section 2.3.

Section 12.2 *Titles and Captions*. All article or section titles or captions in this Agreement are for convenience only. They shall not be deemed part of this Agreement and in no way define, limit, extend or describe the scope or intent of any provisions hereof. Except as specifically provided otherwise, references to "Articles" and "Sections" are to articles and sections of this Agreement.

Section 12.3 *Pronouns and Plurals*. Whenever the context may require, any pronoun used in this Agreement shall include the corresponding masculine, feminine or neuter forms, and the singular form of nouns, pronouns and verbs shall include the plural and vice-versa.

Section 12.4 *Binding Effect*. This Agreement shall be binding upon and inure to the benefit of the parties hereto and their successors, legal representatives and permitted assigns.

Section 12.5 *Integration*. This Agreement constitutes the entire agreement among the parties hereto pertaining to the subject matter hereof and supersedes all prior agreements and understandings pertaining thereto.

Section 12.6 *Creditors.* None of the provisions of this Agreements shall be for the benefit of, or shall be enforceable by, any creditor of the Partnership.

Section 12.7 *Waiver.* No failure by any party to insist upon the strict performance of any covenant, duty, agreement or condition of this Agreement or to exercise any right or remedy consequent upon a breach thereof shall constitute waiver of any such breach or any other covenant, duty, agreement or condition.

Section 12.8 *Applicable Law*. This Agreement shall be construed in accordance with and governed by the laws of the State of Delaware, without regard to the principles of conflicts of law.

Section 12.9 *Invalidity of Provisions*. If any provision of this Agreement is or becomes invalid, illegal or unenforceable in any respect, the validity, legality and enforceability of the remaining provisions contained herein shall not be affected thereby.

Section 12.10 *Counterparts*. This Agreement may be executed in counterparts, all of which together shall constitute an agreement binding on all the parties hereto, notwithstanding that all such parties are not signatories to the original or the same counterpart.

** * * Remainder of this page intentionally left blank * * **

IN WITNESS WHEREOF, this Agreement has been duly executed by the General Partner and the Limited Partner as of the date first above written.

GENERAL PARTNER:

TEPPCO GP, INC.

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

LIMITED PARTNER:

TEPPCO PARTNERS, L.P.

By: Texas Eastern Products Pipeline Company, LLC,
its general partner

By: /s/ JERRY E. THOMPSON
Name: Jerry E. Thompson
Title: President and Chief Executive Officer

Exhibit 10.65

SECOND AMENDED AND RESTATED

AGREEMENT OF LIMITED PARTNERSHIP OF

TCTM, L.P.

THIS SECOND AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP OF TCTM, L.P., dated as of February 27, 2007 is entered into by and between TEPPCO GP, Inc., a Delaware corporation, as the General Partner (as defined below) and TEPPCO Partners, L.P., a Delaware limited partnership ("TEPPCO"), as the Limited Partner (as defined below).

WHEREAS, the General Partner and the Limited Partner entered into the Amended and Restated Agreement of Limited Partnership of TCTM, L.P. dated as of September 21, 2001 (the "Previous Partnership Agreement");

WHEREAS, on December 8, 2006, the agreement of limited partnership of TEPPCO, which is the Limited Partner and the sole stockholder of the General Partner, was amended and restated, among other things, to delete therefrom provisions requiring approval of the unitholders of TEPPCO to amend the partnership agreement of the Partnership under specified circumstances, such provisions serving no meaningful purpose once the General Partner became a wholly-owned subsidiary of TEPPCO; and

WHEREAS, the General Partner and the Limited Partner desire to amend and restate the Previous Partnership Agreement in its entirety to make such changes as they have deemed appropriate in light of matters described in the foregoing recitals;

NOW, THEREFORE, in consideration of the covenants, conditions and agreements contained herein, the General Partner and the Limited Partner do hereby amend and restate the Previous Partnership Agreement in its entirety as follows:

ARTICLE I
DEFINITIONS

The following definitions shall for all purposes, unless otherwise clearly indicated to the contrary, apply to the terms used in this Agreement.

"Affiliate" means, with respect to any Person, any other Person that directly or indirectly controls, is controlled by or is under common control with, the Person in question. As used herein, the term "control" means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a Person, whether through ownership of voting securities, by contract or otherwise.

"Certificate of Limited Partnership" means the Certificate of Limited Partnership filed with the Secretary of State of the State of Delaware as referenced in Section 2.5, as such Certificate may be amended and/or restated from time to time.

“Code” means the Internal Revenue Code of 1986, as amended and in effect from time to time, as interpreted by the applicable regulations thereunder. Any reference herein to a specific section or sections of the Code shall be deemed to include a reference to any corresponding provision of future law.

“Delaware Act” means the Delaware Revised Uniform Limited Partnership Act, 6 Del. C. Section 17-101 *et seq*., as amended, supplemented or restated from time to time, and any successor to such statute.

“General Partner” means TEPPCO GP, Inc., a Delaware corporation, in its capacity as the general partner of the Partnership, and any successor to TEPPCO GP, Inc., as general partner.

“Indemnitee” has the meaning given such term in Section 10.1(a).

“Limited Partner” means TEPPCO, in its capacity as the limited partner of the Partnership, and any other limited partner admitted to the Partnership from time to time and that is shown as a limited partner on the books and records of the Partnership.

“Partner” means the General Partner or the Limited Partner.

“Partnership” means TCTM, L.P., a Delaware limited partnership.

“Partnership Interest” means the interest of a Partner in the Partnership.

“Percentage Interest” means, as of the date of such determination, (a) 0.001% as to the General Partner and (b) 99.999% as to the Limited Partner.

“Person” means an individual or a corporation, partnership, limited liability company, trust, unincorproated organization, association or other entity.

“Previous Partnership Agreement” has the meaning given such term in the recitals.

“Subsidiary” means a Person controlled by the Partnership directly, or indirectly through one or more intermediaries.

“TEPPCO” means TEPPCO Partners, L.P., a Delaware limited partnership.

ARTICLE II
ORGANIZATIONAL MATTERS

Section 2.1 *Continuation*. The General Partner and the Limited Partner hereby continue this Partnership as a limited partnership pursuant to the provisions of the Delaware Act. This amendment and restatement shall become effective on the date of this Agreement. Except as expressly provided to the contrary in this Agreement, the rights, duties (including fiduciary duties), liabilities and obligations of the Partners and the administration, dissolution and termination of the Partnership shall be governed by the Delaware Act. The Partnership Interest of each Partner shall be personal property for all purposes.

Section 2.2 *Name*. The name of the Partnership shall be "TCTM, L.P." The Partnership's business may be conducted under any other name or names deemed necessary or appropriate by the General Partner, including, without limitation, the name of the General Partner or any Affiliate thereof. The words "Limited Partnership," "L.P.," "Ltd." or similar words or letters shall be included in the Partnership's name where necessary for the purposes of complying with the laws of any jurisdiction that so requires. The General Partner in its sole discretion may change the name of the Partnership at any time and from time to time.

Section 2.3 *Registered Office; Principal Office*. Unless and until changed by the General Partner, the registered office of the Partnership in the State of Delaware shall be located at The Corporation Trust Center, 1209 Orange Street, New Castle County, Wilmington, Delaware 19801 and the registered agent for service of process on the Partnership in the State of Delaware at such registered office shall be The Corporation Trust Company. The principal office of the Partnership and the address of the General Partner shall be 1100 Louisiana Street, Houston, Texas 77002, or such other place as the General Partner may from time to time designate. The Partnership may maintain offices at such other place or places within or outside the State of Delaware as the General Partner deems advisable.

Section 2.4 *Term*. The Partnership commenced upon the filing of the Certificate of Limited Partnership in accordance with the Delaware Act and shall continue in existence until the close of Partnership business on December 31, 2084, or until the earlier termination of the Partnership in accordance with the provisions of this Agreement. The existence of the Partnership as a separate legal entity shall continue until the cancellation of the Certificate of Limited Partnership as provided in the Delaware Act.

Section 2.5 *Certificate of Limited Partnership*. The General Partner has caused the Certificate of Limited Partnership to be filed with the Secretary of State of the State of Delaware as required by the Delaware Act and shall use all reasonable efforts to cause to be filed such other certificates or documents as may be determined by the General Partner in its sole discretion to be reasonable and necessary or appropriate for the formation, continuation, qualification and operation of a limited partnership (or a partnership in which the limited partners have limited liability) in the State of Delaware or any other state in which the Partnership may elect to do business or own property. To the extent that such action is determined by the General Partner in its sole discretion to be reasonable and necessary or appropriate, the General Partner shall file amendments to and restatements of the Certificate of Limited Partnership and do all things to maintain the Partnership as a limited partnership (or a partnership in which the limited partners have limited liability) under the laws of the State of Delaware or of any other state in which the Partnership may elect to do business or own property.

ARTICLE III
PURPOSE

Section 3.1 *Purpose and Business*. The purpose and nature of the business to be conducted by the Partnership shall be (a) to engage in the gathering, transportation and storage of crude oil and natural gas liquids and related products and related activities, (b) to engage directly in, or to enter into or form any corporation, partnership, joint venture, limited liability company or similar arrangement to engage in, any business activity that may be lawfully conducted by a limited partnership organized pursuant to the Delaware Act and, in connection therewith, to exercise all of the rights and powers conferred upon the Partnership pursuant to the agreements relating to such business activity, (c) to do anything necessary or appropriate to the foregoing (including, without limitation, the making of capital contributions or loans to any Subsidiary or in connection with its involvement in the activities referred to in clause (b) of this sentence), and (d) to engage in any other business activity as permitted under Delaware law.

Section 3.2 *Powers*. The Partnership shall be empowered to do any and all acts and things necessary, appropriate, proper, advisable, incidental to or convenient for the furtherance and accomplishment of the purposes and business described in Section 3.1 and for the protection and benefit of the Partnership.

ARTICLE IV
CAPITAL CONTRIBUTIONS

Section 4.1 *Prior Contributions*. Prior to the date hereof, the Limited Partner and the General Partner, or their predecessors, have made capital contributions to the Partnership.

Section 4.2 *Additional Contributions*. A Partner may contribute additional cash or property to the capital of the Partnership, but no Partner has any obligation pursuant to this Agreement to make any such contribution.

Section 4.3 *Return of Contributions; Other Provisions Relating to Contributions.* No Partner shall be entitled to withdraw any part of its capital contributions or its capital account or to receive any distribution from the Partnership, except as provided in this Agreement. An unrepaid capital contribution is not a liability of the Partnership or any Partner, and no interest shall accrue on capital contributions or on balances in Partners' capital accounts.

Section 4.4 *Loans.* A Partner may make secured or unsecured loans to the Partnership, but no Partner has any obligation pursuant to this Agreement to make any such loan. Loans by a Partner to the Partnership shall not be considered capital contributions.

ARTICLE V
CAPITAL ACCOUNTS; ALLOCATIONS; DISTRIBUTIONS

Section 5.1 *Capital Accounts* The Partnership shall maintain for each Partner a separate capital account in accordance with the regulations issued pursuant to Section 704 of the Code and as determined by the General Partner as consistent therewith.

Section 5.2 *Allocations for Tax and Capital Account Purposes*. For federal income tax purposes, each item of income, gain, loss, deduction and credit of the Partnership shall be allocated among the Partners in accordance with their Percentage Interests, except that the General Partner shall have the authority to make such other allocations as are necessary and appropriate to comply with Section 704 of the Code and the regulations issued pursuant thereto.

Section 5.3 *Distributions*. The Partnership shall make distributions to the Partners at such times, and in such forms and amounts, as the General Partner may from time to time determine. Distributions in liquidation of the Partnership shall be made in accordance with the positive balances in the Partners' respective capital accounts maintained pursuant to Section 5.1. All other distributions shall be made to the Partners in accordance with their respective Percentage Interests.

ARTICLE VI
MANAGEMENT AND OPERATIONS OF BUSINESS

The General Partner shall conduct, direct and exercise full control over all activities of the Partnership. Except as otherwise expressly provided in this Agreement, all management powers over the business and affairs of the Partnership shall be exclusively vested in the General Partner. In addition to the powers now or hereafter granted a general partner of a limited partnership under applicable law or which are granted to the General Partner under any other provision of this Agreement, the General Partner shall have full power and authority to do all things and on such terms as it, in its sole discretion, may deem necessary or desirable to conduct the business of the Partnership, to exercise all powers set forth in Section 3.2 and to effectuate the purposes set forth in Section 3.1.

ARTICLE VII
RIGHTS AND OBLIGATIONS OF LIMITED PARTNER

The Limited Partner shall have no liability under this Agreement except as expressly provided in this Agreement or the Delaware Act. The Limited Partner shall not take part in the operation, management or control (within the meaning of the Delaware Act) of the Partnership's business, transact any business in the Partnership's name or have the power to sign documents for or otherwise bind the Partnership. The transaction of any such business by the General Partner, any of its Affiliates or any officer, director, employee, partner, agent or trustee of the General Partner or any of its Affiliates, in its capacity as such, shall not affect, impair or eliminate the limitations on the liability of the Limited Partner under this Agreement.

ARTICLE VIII
DISSOLUTION AND LIQUIDATION

The Partnership shall dissolve, and its affairs shall be wound up, upon (a) the expiration of its term as provided in Section 2.4, (b) the occurrence of an event of withdrawal of the General Partner under the Delaware Act, (c) an election to dissolve the Partnership by the General Partner that is approved by the Limited Partner, (d) entry of a decree of judicial dissolution of the Partnership pursuant to the provisions of the Delaware Act, (e) the sale of all or substantially all of the assets and properties of the Partnership and its Subsidiaries, taken as a whole or (f) the dissolution of TEPPCO, if such dissolution occurs while TEPPCO is a Partner; *provided*, *however*, that the Partnership shall not be dissolved or required to be wound up by reason of any event of withdrawal of the General Partner described in the preceding clause (b), if (i) at the time of such event of withdrawal, there is at least one other general partner of the Partnership who carries on the business of the Partnership (any remaining or successor general partner being hereby authorized to carry on the business of the Partnership) or (ii) within 90 days after the withdrawal, the Limited Partner agrees in writing or votes to continue the business of the Partnership and to the appointment, effective as of the date of withdrawal, of one or more general partners of the Partnership.

ARTICLE IX
AMENDMENT OF PARTNERSHIP AGREEMENT

The General Partner may amend any provision of this Agreement without the consent of the Limited Partner and may execute, swear to, acknowledge, deliver, file and record whatever documents may be required in connection therewith, except that any amendment that would increase the liability of the Limited Partner or materially and adversely affect the rights of the Limited Partner under this Agreement requires the consent of the Limited Partner.

ARTICLE X
INDEMNIFICATION

Section 10.1 *Indemnification*.

(a) To the fullest extent permitted by law but subject to the limitations expressly provided in this Agreement, the General Partner, the Limited Partner and any Person who is or was an officer or director of the General Partner (each, an "Indemnitee") shall each be indemnified and held harmless by the Partnership from and against any and all losses, claims, damages, liabilities (joint or several), expenses (including, without limitation, legal fees and expenses), judgments, fines, penalties, interest, settlements and other amounts arising from any and all claims, demands, actions, suits or proceedings, whether civil, criminal, administrative or investigative, in which any Indemnitee may be involved, or is threatened to be involved, as a party or otherwise, by reason of its status as an Indemnitee; *provided*, that the Indemnitee shall not be indemnified and held harmless if there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which the Indemnitee is seeking indemnification pursuant to this Section 10.1, the Indemnitee acted in bad faith or engaged in fraud, willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was unlawful. Any indemnification pursuant to this Section 10.1 shall be made only out of the assets of the Partnership, it being agreed that the General Partner shall not be personally liable for such indemnification and shall have no obligation to contribute or loan any monies or property to the Partnership to enable it to effectuate such indemnification.

(b) To the fullest extent permitted by law, expenses (including, without limitation, legal fees and expenses) incurred by an Indemnitee in defending any claim, demand, action, suit or proceeding shall, from time to time, be advanced by the Partnership prior to the final disposition of such claim, demand, action, suit or proceeding upon receipt by the Partnership of an undertaking by or on behalf of the Indemnitee to repay such amount if it shall be determined that the Indemnitee is not entitled to be indemnified as authorized in this Section 10.1.

(c) The indemnification provided by this Section 10.1 shall be in addition to any other rights to which an Indemnitee may be entitled under any agreement, as a matter of law or otherwise, both as to actions in the Indemnitee's capacity as an Indemnitee and as to actions in any other capacity, and shall continue as to an Indemnitee who has ceased to serve in such capacity.

(d) The Partnership may purchase and maintain (or reimburse the General Partner or its Affiliates for the cost of) insurance, on behalf of the General Partner and such other Persons as the General Partner shall determine, against any liability that may be asserted against or expense that may be incurred by such Person in connection with the Partnership's activities, whether or not the Partnership would have the power to indemnify such Person against such liabilities under the provisions of this Agreement.

(e) In no event shall the Limited Partner be subjected to personal liability by reason of the indemnification provisions set forth in this Agreement, whether by action of an Indemnitee or otherwise.

(f) An Indemnitee shall not be denied indemnification in whole or in part under this Section 10.1 because the Indemnitee had an interest in the transaction with respect to which the indemnification applies if the transaction was otherwise permitted by the terms of this Agreement.

(g) The provisions of this Section 10.1 are for the benefit of the Indemnitees, their heirs, successors and assigns and shall not be deemed to create any rights for the benefit of any other Persons.

(h) No amendment, modification or repeal of this Section 10.1 or any provision hereof shall in any manner terminate, reduce or impair the right of any past, present or future Indemnitee to be indemnified by the Partnership, nor the obligation of the Partnership to indemnify any such Indemnitee under and in accordance with the provisions of this Section 10.1 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.

(i) THE PROVISIONS OF THE INDEMNIFICATION PROVIDED IN THIS SECTION 10.1 ARE INTENDED BY THE PARTIES TO APPLY EVEN IF SUCH PROVISIONS HAVE THE EFFECT OF EXCULPATING THE INDEMNITEE FROM LEGAL RESPONSIBILITY FOR THE CONSEQUENCES OF SUCH PERSON'S NEGLIGENCE, FAULT OR OTHER CONDUCT.

Section 10.2 *Liability of Indemnitees*.

(a) Notwithstanding anything to the contrary set forth in this Agreement, no Indemnitee shall be liable for monetary damages to the Partnership or any Partner for losses sustained or liabilities incurred as a result of any act or omission of an Indemnitee unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter in question, the Indemnitee acted in bad faith or engaged in fraud, willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was criminal.

(b) Subject to its obligations and duties as General Partner set forth in Article VI, the General Partner may exercise any of the powers granted to it by this Agreement and perform any of the duties imposed upon it hereunder either directly or by or through its agents, and the General Partner shall not be responsible for any misconduct or negligence on the part of any such agent appointed by the General Partner in good faith.

(c) Any amendment, modification or repeal of this Section 10.2 or any provision hereof shall be prospective only and shall not in any way affect the limitations on the liability of an Indemnitee under this Section 10.2 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.

ARTICLE XI
BOOKS AND RECORDS

The General Partner shall keep or cause to be kept at the principal office of the Partnership appropriate books and records with respect to the Partnership's business including, without limitation, all books and records necessary to provide to the Limited Partner any information, lists, and copies of documents required to be provided pursuant to the Delaware Act. Any such records may be maintained in other than a written form if such form is capable of conversion into a written form within a reasonable time.

ARTICLE XII
GENERAL PROVISIONS

Section 12.1 *Addresses and Notices*. Any notice, demand, request or report required or permitted to be given or made to a Partner under this Agreement shall be in writing and shall be deemed given or made if received by it at the principal office of the Partnership referred to in Section 2.3.

Section 12.2 *Titles and Captions*. All article or section titles or captions in this Agreement are for convenience only. They shall not be deemed part of this Agreement and in no way define, limit, extend or describe the scope or intent of any provisions hereof. Except as specifically provided otherwise, references to "Articles" and "Sections" are to articles and sections of this Agreement.

Section 12.3 *Pronouns and Plurals*. Whenever the context may require, any pronoun used in this Agreement shall include the corresponding masculine, feminine or neuter forms, and the singular form of nouns, pronouns and verbs shall include the plural and vice-versa.

Section 12.4 *Binding Effect.* This Agreement shall be binding upon and inure to the benefit of the parties hereto and their successors, legal representatives and permitted assigns.

Section 12.5 *Integration*. This Agreement constitutes the entire agreement among the parties hereto pertaining to the subject matter hereof and supersedes all prior agreements and understandings pertaining thereto.

Section 12.6 *Creditors.* None of the provisions of this Agreements shall be for the benefit of, or shall be enforceable by, any creditor of the Partnership.

Section 12.7 *Waiver.* No failure by any party to insist upon the strict performance of any covenant, duty, agreement or condition of this Agreement or to exercise any right or remedy consequent upon a breach thereof shall constitute waiver of any such breach or any other covenant, duty, agreement or condition.

Section 12.8 *Applicable Law*. This Agreement shall be construed in accordance with and governed by the laws of the State of Delaware, without regard to the principles of conflicts of law.

Section 12.9 *Invalidity of Provisions*. If any provision of this Agreement is or becomes invalid, illegal or unenforceable in any respect, the validity, legality and enforceability of the remaining provisions contained herein shall not be affected thereby.

Section 12.10 *Counterparts*. This Agreement may be executed in counterparts, all of which together shall constitute an agreement binding on all the parties hereto, notwithstanding that all such parties are not signatories to the original or the same counterpart.

** * * Remainder of this page intentionally left blank * * **

IN WITNESS WHEREOF, this Agreement has been duly executed by the General Partner and the Limited Partner as of the date first above written.

GENERAL PARTNER:

TEPPCO GP, INC.

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

LIMITED PARTNER:

TEPPCO PARTNERS, L.P.

By: Texas Eastern Products Pipeline Company, LLC,
its general partner

By: /s/ JERRY E. THOMPSON
Name: Jerry E. Thompson
Title: President and Chief Executive Officer

Exhibit 10.66

THIRD AMENDED AND RESTATED
AGREEMENT OF LIMITED PARTNERSHIP OF
TE PRODUCTS PIPELINE COMPANY, LIMITED PARTNERSHIP

THIS THIRD AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP OF TE PRODUCTS PIPELINE COMPANY, LIMITED PARTNERSHIP, dated as of February 27, 2007 is entered into by and between TEPPCO GP, Inc., a Delaware corporation, as the General Partner (as defined below) and TEPPCO Partners, L.P., a Delaware limited partnership ("TEPPCO"), as the Limited Partner (as defined below).

WHEREAS, the General Partner and the Limited Partner entered into the Second Amended and Restated Agreement of Limited Partnership of TE Products Pipeline Company, Limited Partnership, dated as of September 21, 2001 (the "Previous Partnership Agreement");

WHEREAS, on December 8, 2006, the agreement of limited partnership of TEPPCO, which is the Limited Partner and the sole stockholder of the General Partner, was amended and restated, among other things, to delete therefrom provisions requiring approval of the unitholders of TEPPCO to amend the partnership agreement of the Partnership under specified circumstances, such provisions serving no meaningful purpose once the General Partner became a wholly-owned subsidiary of TEPPCO; and

WHEREAS, the General Partner and the Limited Partner desire to amend and restate the Previous Partnership Agreement in its entirety to make such changes as they have deemed appropriate in light of matters described in the foregoing recitals;

NOW, THEREFORE, in consideration of the covenants, conditions and agreements contained herein, the General Partner and the Limited Partner do hereby amend and restate the Previous Partnership Agreement in its entirety as follows:

ARTICLE I
DEFINITIONS

The following definitions shall for all purposes, unless otherwise clearly indicated to the contrary, apply to the terms used in this Agreement.

"Affiliate" means, with respect to any Person, any other Person that directly or indirectly controls, is controlled by or is under common control with, the Person in question. As used herein, the term "control" means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a Person, whether through ownership of voting securities, by contract or otherwise.

"Certificate of Limited Partnership" means the Certificate of Limited Partnership filed with the Secretary of State of the State of Delaware as referenced in Section 2.5, as such Certificate may be amended and/or restated from time to time.

“Code” means the Internal Revenue Code of 1986, as amended and in effect from time to time, as interpreted by the applicable regulations thereunder. Any reference herein to a specific section or sections of the Code shall be deemed to include a reference to any corresponding provision of future law.

“Delaware Act” means the Delaware Revised Uniform Limited Partnership Act, 6 Del. C. Section 17-101 *et seq*., as amended, supplemented or restated from time to time, and any successor to such statute.

“General Partner” means TEPPCO GP, Inc., a Delaware corporation, in its capacity as the general partner of the Partnership, and any successor to TEPPCO GP, Inc., as general partner.

“Indemnitee” has the meaning given such term in Section 10.1(a).

“Limited Partner” means TEPPCO, in its capacity as the limited partner of the Partnership, and any other limited partner admitted to the Partnership from time to time and that is shown as a limited partner on the books and records of the Partnership.

“Partner” means the General Partner or the Limited Partner.

“Partnership” means TE Products Pipeline Company, Limited Partnership, a Delaware limited partnership.

“Partnership Interest” means the interest of a Partner in the Partnership.

“Percentage Interest” means, as of the date of such determination, (a) 0.001% as to the General Partner and (b) 99.999% as to the Limited Partner.

“Person” means an individual or a corporation, partnership, limited liability company, trust, unincorproated organization, association or other entity.

“Previous Partnership Agreement” has the meaning given such term in the recitals.

“Subsidiary” means a Person controlled by the Partnership directly, or indirectly through one or more intermediaries.

“TEPPCO” means TEPPCO Partners, L.P., a Delaware limited partnership.

ARTICLE II
ORGANIZATIONAL MATTERS

Section 2.1 *Continuation*. The General Partner and the Limited Partner hereby continue this Partnership as a limited partnership pursuant to the provisions of the Delaware Act. This amendment and restatement shall become effective on the date of this Agreement. Except as expressly provided to the contrary in this Agreement, the rights, duties (including fiduciary duties), liabilities and obligations of the Partners and the administration, dissolution and termination of the Partnership shall be governed by the Delaware Act. The Partnership Interest of each Partner shall be personal property for all purposes.

Section 2.2 *Name*. The name of the Partnership shall be “TE Products Pipeline Company, Limited Partnership” The Partnership’s business may be conducted under any other name or names deemed necessary or appropriate by the General Partner, including, without limitation, the name of the General Partner or any Affiliate thereof. The words “Limited Partnership,” “L.P.,” “Ltd.” or similar words or letters shall be included in the Partnership’s name where necessary for the purposes of complying with the laws of any jurisdiction that so requires. The General Partner in its sole discretion may change the name of the Partnership at any time and from time to time.

Section 2.3 *Registered Office; Principal Office*. Unless and until changed by the General Partner, the registered office of the Partnership in the State of Delaware shall be located at The Corporation Trust Center, 1209 Orange Street, New Castle County, Wilmington, Delaware 19801 and the registered agent for service of process on the Partnership in the State of Delaware at such registered office shall be The Corporation Trust Company. The principal office of the Partnership and the address of the General Partner shall be 1100 Louisiana Street, Houston, Texas 77002, or such other place as the General Partner may from time to time designate. The Partnership may maintain offices at such other place or places within or outside the State of Delaware as the General Partner deems advisable.

Section 2.4 *Term*. The Partnership commenced upon the filing of the Certificate of Limited Partnership in accordance with the Delaware Act and shall continue in existence until the close of Partnership business on December 31, 2084, or until the earlier termination of the Partnership in accordance with the provisions of this Agreement. The existence of the Partnership as a separate legal entity shall continue until the cancellation of the Certificate of Limited Partnership as provided in the Delaware Act.

Section 2.5 *Certificate of Limited Partnership*. The General Partner has caused the Certificate of Limited Partnership to be filed with the Secretary of State of the State of Delaware as required by the Delaware Act and shall use all reasonable efforts to cause to be filed such other certificates or documents as may be determined by the General Partner in its sole discretion to be reasonable and necessary or appropriate for the formation, continuation, qualification and operation of a limited partnership (or a partnership in which the limited partners have limited liability) in the State of Delaware or any other state in which the Partnership may elect to do business or own property. To the extent that such action is determined by the General Partner in its sole discretion to be reasonable and necessary or appropriate, the General Partner shall file amendments to and restatements of the Certificate of Limited Partnership and do all things to maintain the Partnership as a limited partnership (or a partnership in which the limited partners have limited liability) under the laws of the State of Delaware or of any other state in which the Partnership may elect to do business or own property.

ARTICLE III
PURPOSE

Section 3.1 *Purpose and Business*. The purpose and nature of the business to be conducted by the Partnership shall be (a) to engage in the common carrier transportation of refined petroleum products and liquefied petroleum gases and related products and related terminaling, storage and other activities through ownership of one or more pipeline systems,

(b) to engage directly in, or to enter into or form any corporation, partnership, joint venture, limited liability company or similar arrangement to engage in, any business activity that may be lawfully conducted by a limited partnership organized pursuant to the Delaware Act and, in connection therewith, to exercise all of the rights and powers conferred upon the Partnership pursuant to the agreements relating to such business activity, (c) to do anything necessary or appropriate to the foregoing (including, without limitation, the making of capital contributions or loans to any Subsidiary or in connection with its involvement in the activities referred to in clause (b) of this sentence), and (d) to engage in any other business activity as permitted under Delaware law.

Section 3.2 *Powers*. The Partnership shall be empowered to do any and all acts and things necessary, appropriate, proper, advisable, incidental to or convenient for the furtherance and accomplishment of the purposes and business described in Section 3.1 and for the protection and benefit of the Partnership.

ARTICLE IV
CAPITAL CONTRIBUTIONS

Section 4.1 *Prior Contributions*. Prior to the date hereof, the Limited Partner and the General Partner, or their predecessors, have made capital contributions to the Partnership.

Section 4.2 *Additional Contributions*. A Partner may contribute additional cash or property to the capital of the Partnership, but no Partner has any obligation pursuant to this Agreement to make any such contribution.

Section 4.3 *Return of Contributions; Other Provisions Relating to Contributions.* No Partner shall be entitled to withdraw any part of its capital contributions or its capital account or to receive any distribution from the Partnership, except as provided in this Agreement. An unrepaid capital contribution is not a liability of the Partnership or any Partner, and no interest shall accrue on capital contributions or on balances in Partners' capital accounts.

Section 4.4 *Loans.* A Partner may make secured or unsecured loans to the Partnership, but no Partner has any obligation pursuant to this Agreement to make any such loan. Loans by a Partner to the Partnership shall not be considered capital contributions.

ARTICLE V
CAPITAL ACCOUNTS; ALLOCATIONS; DISTRIBUTIONS

Section 5.1 *Capital Accounts*. The Partnership shall maintain for each Partner a separate capital account in accordance with the regulations issued pursuant to Section 704 of the Code and as determined by the General Partner as consistent therewith.

Section 5.2 *Allocations for Tax and Capital Account Purposes*. For federal income tax purposes, each item of income, gain, loss, deduction and credit of the Partnership shall be allocated among the Partners in accordance with their Percentage Interests, except that the General Partner shall have the authority to make such other allocations as are necessary and appropriate to comply with Section 704 of the Code and the regulations issued pursuant thereto.

Section 5.3 *Distributions*. The Partnership shall make distributions to the Partners at such times, and in such forms and amounts, as the General Partner may from time to time determine. Distributions in liquidation of the Partnership shall be made in accordance with the positive balances in the Partners' respective capital accounts maintained pursuant to Section 5.1. All other distributions shall be made to the Partners in accordance with their respective Percentage Interests.

ARTICLE VI
MANAGEMENT AND OPERATIONS OF BUSINESS

The General Partner shall conduct, direct and exercise full control over all activities of the Partnership. Except as otherwise expressly provided in this Agreement, all management powers over the business and affairs of the Partnership shall be exclusively vested in the General Partner. In addition to the powers now or hereafter granted a general partner of a limited partnership under applicable law or which are granted to the General Partner under any other provision of this Agreement, the General Partner shall have full power and authority to do all things and on such terms as it, in its sole discretion, may deem necessary or desirable to conduct the business of the Partnership, to exercise all powers set forth in Section 3.2 and to effectuate the purposes set forth in Section 3.1.

ARTICLE VII
RIGHTS AND OBLIGATIONS OF LIMITED PARTNER

The Limited Partner shall have no liability under this Agreement except as expressly provided in this Agreement or the Delaware Act. The Limited Partner shall not take part in the operation, management or control (within the meaning of the Delaware Act) of the Partnership's business, transact any business in the Partnership's name or have the power to sign documents for or otherwise bind the Partnership. The transaction of any such business by the General Partner, any of its Affiliates or any officer, director, employee, partner, agent or trustee of the General Partner or any of its Affiliates, in its capacity as such, shall not affect, impair or eliminate the limitations on the liability of the Limited Partner under this Agreement.

ARTICLE VIII
DISSOLUTION AND LIQUIDATION

The Partnership shall dissolve, and its affairs shall be wound up, upon (a) the expiration of its term as provided in Section 2.4, (b) the occurrence of an event of withdrawal of the General Partner under the Delaware Act, (c) an election to dissolve the Partnership by the General Partner that is approved by the Limited Partner, (d) entry of a decree of judicial dissolution of the Partnership pursuant to the provisions of the Delaware Act, (e) the sale of all or substantially all of the assets and properties of the Partnership and its Subsidiaries, taken as a whole or (f) the dissolution of TEPPCO, if such dissolution occurs while TEPPCO is a Partner; *provided, however*, that the Partnership shall not be dissolved or required to be wound up by reason of any event of withdrawal of the General Partner described in the preceding clause (b), if (i) at the time of such event of withdrawal, there is at least one other general partner of the Partnership who carries on the business of the Partnership (any remaining or successor general partner being hereby authorized to carry on the business of the Partnership) or (ii) within 90 days after the withdrawal, the Limited Partner agrees in writing or votes to continue the business of the Partnership and to the appointment, effective as of the date of withdrawal, of one or more general partners of the Partnership.

ARTICLE IX
AMENDMENT OF PARTNERSHIP AGREEMENT

The General Partner may amend any provision of this Agreement without the consent of the Limited Partner and may execute, swear to, acknowledge, deliver, file and record whatever documents may be required in connection therewith, except that any amendment that would increase the liability of the Limited Partner or materially and adversely affect the rights of the Limited Partner under this Agreement requires the consent of the Limited Partner.

ARTICLE X
INDEMNIFICATION

Section 10.1 *Indemnification*.

(a) To the fullest extent permitted by law but subject to the limitations expressly provided in this Agreement, the General Partner, the Limited Partner and any Person who is or was an officer or director of the General Partner (each, an "Indemnitee") shall each be indemnified and held harmless by the Partnership from and against any and all losses, claims, damages, liabilities (joint or several), expenses (including, without limitation, legal fees and expenses), judgments, fines, penalties, interest, settlements and other amounts arising from any and all claims, demands, actions, suits or proceedings, whether civil, criminal, administrative or investigative, in which any Indemnitee may be involved, or is threatened to be involved, as a party or otherwise, by reason of its status as an Indemnitee; *provided*, that the Indemnitee shall not be indemnified and held harmless if there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which the Indemnitee is seeking indemnification pursuant to this Section 10.1, the Indemnitee acted in bad faith or engaged in fraud, willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was unlawful. Any indemnification pursuant to this Section 10.1 shall be made only out of the assets of the Partnership, it being agreed that the General Partner shall not be personally liable for such indemnification and shall have no obligation to contribute or loan any monies or property to the Partnership to enable it to effectuate such indemnification.

(b) To the fullest extent permitted by law, expenses (including, without limitation, legal fees and expenses) incurred by an Indemnitee in defending any claim, demand, action, suit or proceeding shall, from time to time, be advanced by the Partnership prior to the final disposition of such claim, demand, action, suit or proceeding upon receipt by the Partnership of an undertaking by or on behalf of the Indemnitee to repay such amount if it shall be determined that the Indemnitee is not entitled to be indemnified as authorized in this Section 10.1.

(c) The indemnification provided by this Section 10.1 shall be in addition to any other rights to which an Indemnitee may be entitled under any agreement, as a matter of law or otherwise, both as to actions in the Indemnitee's capacity as an Indemnitee and as to actions in any other capacity, and shall continue as to an Indemnitee who has ceased to serve in such capacity.

(d) The Partnership may purchase and maintain (or reimburse the General Partner or its Affiliates for the cost of) insurance, on behalf of the General Partner and such other Persons as the General Partner shall determine, against any liability that may be asserted against or expense that may be incurred by such Person in connection with the Partnership's activities, whether or not the Partnership would have the power to indemnify such Person against such liabilities under the provisions of this Agreement.

(e) In no event shall the Limited Partner be subjected to personal liability by reason of the indemnification provisions set forth in this Agreement, whether by action of an Indemnitee or otherwise.

(f) An Indemnitee shall not be denied indemnification in whole or in part under this Section 10.1 because the Indemnitee had an interest in the transaction with respect to which the indemnification applies if the transaction was otherwise permitted by the terms of this Agreement.

(g) The provisions of this Section 10.1 are for the benefit of the Indemnitees, their heirs, successors and assigns and shall not be deemed to create any rights for the benefit of any other Persons.

(h) No amendment, modification or repeal of this Section 10.1 or any provision hereof shall in any manner terminate, reduce or impair the right of any past, present or future Indemnitee to be indemnified by the Partnership, nor the obligation of the Partnership to indemnify any such Indemnitee under and in accordance with the provisions of this Section 10.1 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.

(i) THE PROVISIONS OF THE INDEMNIFICATION PROVIDED IN THIS SECTION 10.1 ARE INTENDED BY THE PARTIES TO APPLY EVEN IF SUCH PROVISIONS HAVE THE EFFECT OF EXCULPATING THE INDEMNITEE FROM LEGAL RESPONSIBILITY FOR THE CONSEQUENCES OF SUCH PERSON'S NEGLIGENCE, FAULT OR OTHER CONDUCT.

Section 10.2 *Liability of Indemnitees*.

(a) Notwithstanding anything to the contrary set forth in this Agreement, no Indemnitee shall be liable for monetary damages to the Partnership or any Partner for losses sustained or liabilities incurred as a result of any act or omission of an Indemnitee unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter in question, the Indemnitee acted in bad faith or engaged in fraud, willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was criminal.

(b) Subject to its obligations and duties as General Partner set forth in Article VI, the General Partner may exercise any of the powers granted to it by this Agreement and perform any of the duties imposed upon it hereunder either directly or by or through its agents, and the General Partner shall not be responsible for any misconduct or negligence on the part of any such agent appointed by the General Partner in good faith.

(c) Any amendment, modification or repeal of this Section 10.2 or any provision hereof shall be prospective only and shall not in any way affect the limitations on the liability of an Indemnitee under this Section 10.2 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.

ARTICLE XI
BOOKS AND RECORDS

The General Partner shall keep or cause to be kept at the principal office of the Partnership appropriate books and records with respect to the Partnership's business including, without limitation, all books and records necessary to provide to the Limited Partner any information, lists, and copies of documents required to be provided pursuant to the Delaware Act. Any such records may be maintained in other than a written form if such form is capable of conversion into a written form within a reasonable time.

ARTICLE XII
GENERAL PROVISIONS

Section 12.1 *Addresses and Notices*. Any notice, demand, request or report required or permitted to be given or made to a Partner under this Agreement shall be in writing and shall be deemed given or made if received by it at the principal office of the Partnership referred to in Section 2.3.

Section 12.2 *Titles and Captions*. All article or section titles or captions in this Agreement are for convenience only. They shall not be deemed part of this Agreement and in no way define, limit, extend or describe the scope or intent of any provisions hereof. Except as specifically provided otherwise, references to "Articles" and "Sections" are to articles and sections of this Agreement.

Section 12.3 *Pronouns and Plurals*. Whenever the context may require, any pronoun used in this Agreement shall include the corresponding masculine, feminine or neuter forms, and the singular form of nouns, pronouns and verbs shall include the plural and vice-versa.

Section 12.4 *Binding Effect*. This Agreement shall be binding upon and inure to the benefit of the parties hereto and their successors, legal representatives and permitted assigns.

Section 12.5 *Integration*. This Agreement constitutes the entire agreement among the parties hereto pertaining to the subject matter hereof and supersedes all prior agreements and understandings pertaining thereto.

Section 12.6 *Creditors.* None of the provisions of this Agreements shall be for the benefit of, or shall be enforceable by, any creditor of the Partnership.

Section 12.7 *Waiver.* No failure by any party to insist upon the strict performance of any covenant, duty, agreement or condition of this Agreement or to exercise any right or remedy consequent upon a breach thereof shall constitute waiver of any such breach or any other covenant, duty, agreement or condition.

Section 12.8 *Applicable Law*. This Agreement shall be construed in accordance with and governed by the laws of the State of Delaware, without regard to the principles of conflicts of law.

Section 12.9 *Invalidity of Provisions*. If any provision of this Agreement is or becomes invalid, illegal or unenforceable in any respect, the validity, legality and enforceability of the remaining provisions contained herein shall not be affected thereby.

Section 12.10 *Counterparts*. This Agreement may be executed in counterparts, all of which together shall constitute an agreement binding on all the parties hereto, notwithstanding that all such parties are not signatories to the original or the same counterpart.

* * * *Remainder of this page intentionally left blank* * * *

IN WITNESS WHEREOF, this Agreement has been duly executed by the General Partner and the Limited Partner as of the date first above written.

GENERAL PARTNER:

TEPPCO GP, INC.

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

LIMITED PARTNER:

TEPPCO PARTNERS, L.P.

By: Texas Eastern Products Pipeline Company, LLC, its general partner

By: /s/ JERRY E. THOMPSON
Name: Jerry E. Thompson
Title: President and Chief Executive Officer

Exhibit 12.1

Statement of Computation of Ratio of Earnings to Fixed Charges

	2002	2003	2004 (in thousands)	2005	2006
Earnings					
Income From Continuing Operations *	105,882	104,958	112,658	138,639	157,886
Fixed Charges	73,381	93,294	80,695	93,414	101,905
Distributed Income of Equity Investment	30,938	28,003	47,213	37,085	63,483
Capitalized Interest	(4,345)	(5,290)	(4,227)	(6,759)	(10,681)
Total Earnings	205,856	220,965	236,339	262,379	312,593
Fixed Charges					
Interest Expense	66,192	84,250	72,053	81,861	86,171
Capitalized Interest	4,345	5,290	4,227	6,759	10,681
Rental Interest Factor	2,844	3,754	4,415	4,794	5,053
Total Fixed Charges	73,381	93,294	80,695	93,414	101,905
Ratio: Earnings / Fixed Charges	2.81	2.37	2.93	2.81	3.07

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

Exhibit 21

Subsidiaries of the Partnership

TEPPCO Partners, L.P. (Delaware)

TEPPCO GP, Inc. (Delaware)
TE Products Pipeline Company, Limited Partnership (Delaware)
TEPPCO Terminals Company, L.P. (Delaware)
TEPPCO Interests, LLC (Delaware)
TEPPCO Terminaling and Marketing Company, LLC (Delaware)
TEPPCO Colorado, LLC (Delaware)
TEPPCO Midstream Companies, L.P. (Delaware)
TEPPCO NGL Pipelines, LLC (Delaware)
Chaparral Pipeline Company, L.P. (Delaware)
Quanah Pipeline Company, L.P. (Delaware)
Panola Pipeline Company, L.P. (Delaware)
Dean Pipeline Company, L.P. (Delaware)
Wilcox Pipeline Company, L.P. (Delaware)
Val Verde Gas Gathering Company, L.P. (Delaware)
TCTM, L.P. (Delaware)
TEPPCO Crude GP, LLC (Delaware)
TEPPCO Crude Pipeline, L.P. (Delaware)
TEPPCO Seaway, L.P. (Delaware)
TEPPCO Crude Oil, L.P. (Delaware)
Lubrication Services, L.P. (Delaware)

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-110207 and 33-81976 on Form S-3, and Registration Statement No. 333-82892 on Form S-8 of our report dated February 28, 2007, relating to the consolidated financial statements of TEPPCO Partners, L.P. and subsidiaries (such report expresses an unqualified opinion and includes an explanatory paragraph referring to the changes in the method of financial statement presentation related to purchases and sales of inventory with the same counterparty) and our report dated February 28, 2007 relating to management's report on the effectiveness of internal control over financial reporting, appearing in this Annual Report on Form 10-K of TEPPCO Partners, L.P. and subsidiaries for the year ended December 31, 2006.

/s/ Deloitte & Touche LLP

Houston, Texas
February 28, 2007

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To Partners of
TEPPCO Partners, L.P.:

We consent to the incorporation by reference in the registration statements on Form S-3 (No. 333-110207 and 33-81976) and on Form S-8 (No. 333-82892) of TEPPCO Partners, L.P. of our report dated February 28, 2006, except for the effects of discontinued operations, as discussed in Note 11, which is as of June 1, 2006, with respect to the consolidated balance sheet of TEPPCO Partners, L.P. and subsidiaries as of December 31, 2005, and the related consolidated statements of income and comprehensive income, partners' capital, and cash flows for each of the years in the two-year period ended December 31, 2005, which report appears in the December 31, 2006 annual report on Form 10-K of TEPPCO Partners, L.P. and subsidiaries.

KPMG LLP

Houston, Texas
February 28, 2007

Exhibit 24

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned directors and/or officers of TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC (the “Company”), a Delaware limited liability company, acting in its capacity as general partner of TEPPCO Partners, L.P., a Delaware limited partnership (the “Partnership”), does hereby appoint WILLIAM G. MANIAS, his true and lawful attorney and agent to do any and all acts and things, and execute any and all instruments which, with the advice and consent of Counsel, said attorney and agent may deem necessary or advisable to enable the Company and Partnership to comply with the Securities Act of 1934, as amended, and any rules, regulations, and requirements thereof, to sign his name as a director and/or officer of the Company to the Form 10-K Report for TEPPCO Partners, L.P. , each for the year ended December 31, 2006, and to any instrument or document filed as a part of, or in accordance with, each said Form 10-K or amendment thereto; and the undersigned do hereby ratify and confirm all that said attorney and agent shall do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have subscribed these presents this 26th day of February, 2007.

/s/ MICHAEL B. BRACY
Michael B. Bracy
Director

/s/ MURRAY H. HUTCHISON
Murray H. Hutchison
Director

/s/ RICHARD S. SNELL
Richard S. Snell
Director

/s/ JERRY E. THOMPSON
Jerry E. Thompson
Director

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

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 annual report on Form 10-K of TEPPCO Partners, L.P.;

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

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

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

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

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

February 28, 2007

/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 annual report on Form 10-K of TEPPCO Partners, L.P.;

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

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

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

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

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

February 28, 2007

/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 Annual Report of TEPPCO Partners, L.P. (the “Company”) on Form 10-K for the year ended December 31, 2006 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, Jerry E. Thompson, President and Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC, the general partner of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ JERRY E. THOMPSON

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

February 28, 2007

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 Annual Report of TEPPCO Partners, L.P. (the “Company”) on Form 10-K for the year ended December 31, 2006 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, William G. Manias, Vice President and Chief Financial Officer of Texas Eastern Products Pipeline Company, LLC, the general partner of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

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

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

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

February 28, 2007

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.