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

FORM 8-K

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

Date of report (Date of earliest event reported): October 26, 2009

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**1-14323**	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

1100 Louisiana, 10th Floor, Houston, Texas	**77002**
(Address of Principal Executive Offices)	(Zip Code)

(713) 381-6500
(Registrant's Telephone Number, including Area Code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events.

Unless the context requires otherwise, references in this Current Report on Form 8-K to "we," "us," "our," or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries, which now include TEPPCO Partners, L.P. and its general partner.

As described in our Quarterly Report on Form 10-Q for the period ended September 30, 2009 and within this Current Report on Form 8-K, we completed the related mergers of our wholly owned subsidiaries with TEPPCO Partners, L.P. ("TEPPCO") and its general partner, Texas Eastern Products Pipeline Company, LLC ("TEPPCO GP"), on October 26, 2009 (such related mergers referred to herein individually and together as the "TEPPCO Merger").

The TEPPCO Merger transactions were accounted for as a reorganization of entities under common control in a manner similar to a pooling of interests. The financial and operating activities of Enterprise Products Partners, TEPPCO and Enterprise GP Holdings L.P. and their respective general partners, and EPCO, Inc. and its privately held subsidiaries, are under the common control of Dan L. Duncan. The purpose of the disclosures presented in this Current Report on Form 8-K is to recast certain financial and other information of Enterprise Products Partners to include TEPPCO and TEPPCO GP.

The inclusion of TEPPCO and TEPPCO GP in the supplemental consolidated financial statements and other disclosures presented within this Current Report on Form 8-K was effective January 1, 2005 since an affiliate of EPCO under common control with Enterprise Products Partners originally acquired ownership interests in TEPPCO GP in February 2005.

Our supplemental consolidated financial statements prior to the effective date of the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third party and related party ownership interests in TEPPCO and TEPPCO GP prior to the merger have been reflected as "Former owners of TEPPCO," which is a component of noncontrolling interest.

We revised our business segments and related disclosures to reflect the TEPPCO Merger. Our reorganized business segments reflect the manner in which these businesses are managed and reviewed by the chief executive officer of our general partner. Under our new business segment structure, we have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services.

An investment in our common units involves certain risks. If any of these risks were to occur, our business, financial position, results of operations and cash flows could be materially adversely affected. As recast, Item 1A of Exhibit 99.1 lists our current key risk factors.

Item 9.01. Financial Statements and Exhibits.

(d) Exhibits.

Exhibit No.	Description
23.1	Consent of Deloitte & Touche LLP
99.1	Recast of Items 1, 1A, 2, 6, 7 and 7A of Enterprise Products Partners L.P.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2008.
99.2	Recast of Item 8 of Enterprise Products Partners L.P.'s Current Report on Form 8-K dated July 8, 2009.
99.3	Recast of Item 1 of Enterprise Products Partners L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2009.
99.4	Recast of Items 2 and 3 of Enterprise Products Partners L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2009.
99.5	Recast summarized financial and operating data of Enterprise Products Partners L.P. for the quarters ended March 31, 2009 and June 30, 2009.
101.CAL	XBRL Calculation Document
101.DEF	XBRL Definition Document
101.INS	XBRL Instance Document
101.LAB	XBRL Labels Document
101.PRE	XBRL Presentation Document
101.SCH	XBRL Schema Document

SIGNATURES

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

ENTERPRISE PRODUCTS PARTNERS L.P.

By: Enterprise Products GP, LLC, as General Partner

Date: December 4, 2009

By: /s/ Michael J. Knesek
Name: Michael J. Knesek
Title: Senior Vice President, Controller
and Principal Accounting Officer of
Enterprise Products GP, LLC

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in (i) Registration Statement Nos. 333-36856, 333-82486, 333-115633, 333-115634, 333-150680, 333-162666 of Enterprise Products Partners L.P. on Form S-8; (ii) Registration Statement No. 333-145709 of Enterprise Products Partners L.P. and Enterprise Products Operating LLC on Form S-3; and (iii) Registration Statement No. 333-142106 of Enterprise Products Partners L.P. on Form S-3 of our report dated December 4, 2009 (which report expresses an unqualified opinion and includes an explanatory paragraph concerning the retroactive effects of the common control acquisition of TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC and the related change in business segments described in Note 1), relating to the supplemental consolidated financial statements of Enterprise Products Partners L.P. and subsidiaries, appearing in this Current Report on Form 8-K of Enterprise Products Partners L.P.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
December 4, 2009

ENTERPRISE PRODUCTS PARTNERS L.P.
RECAST OF CERTAIN SECTIONS OF THE 2008 ANNUAL REPORT ON FORM 10-K

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SIGNIFICANT RELATIONSHIPS REFERENCED IN THIS EXHIBIT 99.1

Unless the context requires otherwise, references to “we,” “us,” “our,” or “Enterprise Products Partners” are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries, which now includes TEPPCO Partners, L.P. and its general partner.

References to “EPO” mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts substantially all of its business.

References to “Duncan Energy Partners” mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “DEP.” References to “DEP GP” mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to “EPGP” mean Enterprise Products GP, LLC, which is our general partner.

References to “Enterprise GP Holdings” mean Enterprise GP Holdings L.P., a publicly traded limited partnership, the units of which are listed on the NYSE under the ticker symbol “EPE.” Enterprise GP Holdings owns EPGP. References to “EPE Holdings” mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to “TEPPCO” and “TEPPCO GP” mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries. On October 26, 2009, we completed the mergers with TEPPCO and TEPPCO GP (such related mergers referred to herein individually and together as the “TEPPCO Merger”).

References to “Energy Transfer Equity” mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. (“ETP”). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “ETE.” The general partner of Energy Transfer Equity is LE GP, LLC (“LE GP”). On May 7, 2007, Enterprise GP Holdings acquired noncontrolling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to “Employee Partnerships” mean EPE Unit L.P. (“EPE Unit I”), EPE Unit II, L.P. (“EPE Unit II”), EPE Unit III, L.P. (“EPE Unit III”), Enterprise Unit L.P. (“Enterprise Unit”), EPCO Unit L.P. (“EPCO Unit”), TEPPCO Unit L.P. (TEPPCO Unit I”) and TEPPCO Unit II L.P. (“TEPPCO Unit II”), collectively, all of which are private company affiliates of EPCO, Inc.

References to “EPCO” mean EPCO, Inc. and its wholly owned private company affiliates, which are related parties to all of the foregoing named entities.

We, TEPPCO, TEPPCO GP, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings and EPE Holdings are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

Recast of Items 1 and 2. ***Business and Properties*****.**

General

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs"), crude oil, refined products and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We conduct substantially all of our business through EPO. Our principal executive offices are located at 1100 Louisiana, 10th Floor, Houston, Texas 77002, our telephone number is (713) 381-6500 and our website is www.epplp.com.

We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD." We are owned 98% by our limited partners and 2% by our general partner, EPGP. Our general partner is owned by a publicly traded affiliate, Enterprise GP Holdings, the units of which are listed on the NYSE under the ticker symbol "EPE."

Business Strategy

We operate an integrated network of midstream energy assets. Our business strategies are to:

- capitalize on expected development in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountains, Midcontinent and U.S. Gulf Coast regions, including the Barnett Shale, Haynesville Shale, Eagle Ford Shale and Gulf of Mexico producing regions;

- capitalize on demand growth for natural gas, NGLs, crude oil and refined products;

- maintain a diversified portfolio of midstream energy assets and expand this asset base through growth capital projects and accretive acquisitions of complementary midstream energy assets;

- share capital costs and risks through joint ventures or alliances with strategic partners, including those that will provide the raw materials for these growth projects or purchase the project's end products; and

- increase fee-based cash flows by investing in pipelines and other fee-based businesses.

As noted above, part of our business strategy involves expansion through growth capital projects. We expect that these projects will enhance our existing asset base and provide us with additional growth opportunities in the future. For information regarding our growth capital projects, see "Liquidity and Capital Resources - Capital Spending" included under Item 7 within this Exhibit 99.1.

Financial Information by Business Segment

For information regarding our business segments, see Note 16 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K. Such financial information is incorporated by reference into this Item 1 and 2 discussion.

Recent Developments

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 of our common units for each TEPPCO unit. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. TEPPCO's units, which had been trading on the NYSE under the ticker symbol TPP, have been delisted and are no longer publicly traded.

A privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

Under the terms of the TEPPCO Merger agreements, Enterprise GP Holdings received 1,331,681 of our common units and an increase in the capital account of EPGP to maintain its 2% general partner interest in us as consideration for 100% of the membership interests of TEPPCO GP. Following the closing of the TEPPCO Merger, affiliates of EPCO owned approximately 31.3% of our outstanding limited partner units, including 3.4% owned by Enterprise GP Holdings.

The post-merger partnership, which retains the name Enterprise Products Partners L.P., accesses the largest producing basins of natural gas, NGLs and crude oil in the U.S., and serves some of the largest consuming regions for natural gas, NGLs, refined products, crude oil and petrochemicals. The post-merger partnership owns almost 48,000 miles of pipelines comprised of over 22,000 miles of NGL, refined product and petrochemical pipelines, over 20,000 miles of natural gas pipelines and more than 5,000 miles of crude oil pipelines. The merged partnership's logistical assets include approximately 200 million barrels of NGL, refined product and crude oil storage capacity; 27 billion cubic feet of natural gas storage capacity; one of the largest NGL import/export terminals in the U.S., located on the Houston Ship Channel; 60 NGL, refined product and chemical terminals spanning the U.S. from the west coast to the east coast; and crude oil import terminals on the Texas Gulf Coast. The post-merger partnership owns interests in 17 fractionation plants with over 600 thousand barrels per day ("MBPD") of net capacity; 25 natural gas processing plants with a net capacity of approximately 9 billion cubic feet per day; and 3 butane isomerization facilities with a capacity of 116 MBPD. The post-merger partnership is also one of the largest inland tank barge companies in the U.S.

The TEPPCO Merger transactions were accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. The financial and operating activities of Enterprise Products Partners, TEPPCO and Enterprise GP Holdings and their respective general partners, and EPCO and its privately held subsidiaries, are under the common control of Dan L. Duncan.

For information regarding additional recent developments, see "Recent Developments" included under Item 7 within this Exhibit 99.1, which is incorporated by reference into this Item 1 and 2 discussion.

Segment Discussion

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. In connection with the TEPPCO Merger, we revised and renamed our business segments. Under our new business segment structure, we have five reportable business segments:

- NGL Pipelines & Services;
- Onshore Natural Gas Pipelines & Services;
- Onshore Crude Oil Pipelines & Services;
- Offshore Pipelines & Services; and
- Petrochemical & Refined Products Services.

Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

The following sections present an overview of our business segments, including information regarding the principal products produced, services rendered, seasonality, competition and regulation. Our results of operations and financial condition are subject to a variety of risks. For information regarding our current key risk factors, see Item 1A within this Exhibit 99.1.

Our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental, safety and other matters. For a discussion of the principal effects such laws and regulations have on our business, see "Regulation" and "Environmental and Safety Matters" included within this Item 1 and 2.

Our revenues are derived from a wide customer base. During 2008, 2007 and 2006, our largest customer was Valero Energy Corporation and its affiliates, which accounted for 11.2%, 8.9% and 9.3%, respectively, of our revenues.

On January 6, 2009, LyondellBasell Industries ("LBI"), one of our largest customers, announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. LBI accounted for 5.9% of our consolidated revenues during 2008. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. In addition, we are seeking to have LBI accept certain contracts and have filed claims pursuant to current Bankruptcy Court Orders that we expect will allow us to recover the majority of the remaining credit exposure.

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

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

The following discussion of our business segments provides information regarding our principal plants, pipelines and other assets at February 2, 2009. For information regarding our results of operations, including significant measures of historical throughput, production and processing rates, see Item 7 within this Exhibit 99.1.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our (i) natural gas processing business and related NGL marketing activities; (ii) NGL pipelines aggregating approximately 15,725 miles including our 7,808-mile Mid-America Pipeline System; (iii) NGL and related product storage facilities; and (iv) NGL fractionation facilities. This segment also includes our import and export terminal operations.

NGL products (ethane, propane, normal butane, isobutane and natural gasoline) are used as raw materials by the petrochemical industry, as feedstocks by refiners in the production of motor gasoline and by industrial and residential users as fuel. Ethane is primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating, engine and industrial fuel. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline and to derive isobutane through isomerization. Isobutane is fractionated from mixed butane (a mixed stream of normal butane and isobutane) or produced from normal butane through the process of isomerization, principally for use in refinery alkylation to enhance the octane content of motor gasoline, in the production of isooctane and other octane additives and in the production of propylene oxide. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

Natural gas processing and related NGL marketing activities. At the core of our natural gas processing business are 24 processing plants located in Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. Natural gas produced at the wellhead especially in association with crude oil contains varying amounts of NGLs. This “rich” natural gas in its raw form is usually not acceptable for transportation in the nation’s major natural gas pipeline systems or for commercial use as a fuel. Natural gas processing plants remove the NGLs from the natural gas stream, enabling the natural gas to meet pipeline and commercial quality specifications. In addition, on an energy equivalent basis, NGLs generally have a greater economic value as a raw material for petrochemical and motor gasoline production than their value as components of the natural gas stream. After extraction, we typically transport the mixed NGLs to a centralized facility for fractionation into purity NGL products such as ethane, propane, normal butane, isobutane and natural gasoline. The purity NGL products can then be used in our NGL marketing activities to meet contractual requirements or sold on spot and forward markets.

When operating and extraction costs of natural gas processing plants are higher than the incremental value of the NGL products that would be extracted, the recovery levels of certain NGL products, principally ethane, may be reduced or eliminated. This leads to a reduction in NGL volumes available for transportation and fractionation.

In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid contracts (a combination of percent-of-liquids and fee-based contract terms) and keepwhole contracts. Under margin-band and keepwhole contracts, we take ownership of mixed NGLs extracted from the producer’s natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers on NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we earn and sell is less than the total amount of NGLs extracted from the producers’ natural gas. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract and generally bears the natural gas cost for shrinkage and plant fuel. Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer’s behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer. The NGL volumes we earn and take title to in connection with our processing activities are referred to as our equity NGL production.

In general, our percent-of-liquids, hybrid and keepwhole contracts give us the right (but not the obligation) to process natural gas for a producer; thus, we are protected from processing at an economic loss during times when the sum of our costs exceeds the value of the mixed NGLs of which we would take ownership. Generally, our natural gas processing agreements have terms ranging from month-to-month to life of the producing lease. Intermediate terms of one to ten years are also common.

To the extent that we are obligated under our margin-band and keepwhole gas processing contracts to compensate the producer for the natural gas equivalent energy value of mixed NGLs we extract from the natural gas stream, we are exposed to various risks, primarily commodity price fluctuations. However, our margin band contracts contain terms which limit our exposure to such risks. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. Periodically, we attempt to mitigate these risks through the use of commodity derivative instruments. For information regarding our use of commodity derivative instruments, see "Commodity Risk Hedging Program" included under Item 7A within this Exhibit 99.1.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs obtained through our processing activities and purchases from third parties on the open market. These sales contracts may also include forward product sales contracts. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

NGL pipelines, storage facilities and import/export terminals. Our NGL pipeline, storage and terminaling operations include approximately 15,725 miles of NGL pipelines, 157.4 MMBbls of working capacity of NGL and related product storage and two import/export facilities.

Our NGL pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities, refineries and import terminals to fractionation plants and storage facilities; distribute and collect NGL products to and from fractionation plants, petrochemical plants and refineries; and deliver propane to customers along the Dixie Pipeline and certain sections of the Mid-America Pipeline System. Revenue from our NGL pipeline transportation agreements is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers (including those charged to our NGL and petrochemical marketing activities, which are eliminated in the preparation of our consolidated financial statements). The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the Federal Energy Regulatory Commission ("FERC"). Typically, we do not take title to the products transported by our NGL pipelines; rather, the shipper retains title and the associated commodity price risk.

Our NGL and related product storage facilities are integral parts of our operations. In general, our underground storage wells are used to store our and our customers' mixed NGLs, NGL products and petrochemical products. We collect storage revenues under our NGL and related product storage contracts based on the number of days a customer has volumes in storage multiplied by a storage rate (as defined in each contract). With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for customers in our underground storage wells. The customers pay reservation fees based on the quantity of capacity reserved rather than the actual quantity utilized. When a customer exceeds its reserved capacity, we charge those customers an excess storage fee. In addition, we charge our customers throughput fees based on volumes injected and withdrawn from the storage facility. Accordingly, the profitability of our storage operations is dependent upon the level of capacity reserved by our customers, the volume of product injected and withdrawn from our underground caverns and the level of fees charged.

We operate NGL import and export facilities located on the Houston Ship Channel in southeast Texas. Our import facility is primarily used to offload volumes for delivery to our NGL storage and fractionation facilities near Mont Belvieu, Texas. Our export facility includes an NGL products chiller and related equipment used for loading refrigerated marine tankers for third-party export customers. Revenues from our import and export services are primarily based on fees per unit of volume loaded or unloaded and may also include demand payments. Accordingly, the profitability of our import and export activities primarily depends on the available quantities of NGLs to be loaded and offloaded and the fees we charge for these services.

NGL fractionation. We own or have interests in ten NGL fractionation facilities located in Texas, Louisiana and Colorado. NGL fractionation facilities separate mixed NGL streams into purity NGL products. The three primary sources of mixed NGLs fractionated in the United States are (i) domestic natural gas processing plants, (ii) domestic crude oil refineries and (iii) imports of butane and propane mixtures. The mixed NGLs delivered from domestic natural gas processing plants and crude oil refineries to our NGL fractionation facilities are typically transported by NGL pipelines and, to a lesser extent, by railcar and truck.

Mixed NGLs extracted by domestic natural gas processing plants represent the largest source of volumes processed by our NGL fractionators. Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from Gulf Coast, Rocky Mountain and Midcontinent natural gas processing plants, will be available for fractionation in commercially viable quantities for the foreseeable future. Significant volumes of mixed NGLs are contractually committed to our NGL fractionation facilities by joint owners and third-party customers.

The majority of our NGL fractionation facilities process mixed NGL streams for third-party customers and support our NGL marketing activities under fee-based arrangements. These fees (typically in cents per gallon) are subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs. At our Norco facility, we perform fractionation services for certain customers under percent-of-liquids contracts. The results of operations of our NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and either the level of fractionation fees charged (under fee-based contracts) or the value of NGLs received (under percent-of-liquids arrangements). Our fee-based customers generally retain title to the NGLs that we process for them; however, we are exposed to fluctuations in NGL prices (i.e., commodity price risk) to the extent we fractionate volumes for customers under percent-of-liquids arrangements. Periodically, we attempt to mitigate these risks through the use of commodity derivative instruments. For information regarding our use of commodity derivative instruments, see "Commodity Risk Hedging Program" included under Item 7A within this Exhibit 99.1.

Seasonality. Our natural gas processing and NGL fractionation operations exhibit little to no seasonal variation. Likewise, our NGL pipeline operations have not exhibited a significant degree of seasonality overall. However, propane transportation volumes are generally higher in the October through March timeframe in connection with increased use of propane for heating in the upper Midwest and southeastern United States. Our facilities located in the southern United States may be affected by weather events such as hurricanes and tropical storms originating in the Gulf of Mexico.

We operate our NGL and related product storage facilities based on the needs and requirements of our customers in the NGL, petrochemical, heating and other related industries. We usually experience an increase in the demand for storage services during the spring and summer months due to increased feedstock storage requirements for motor gasoline production and a decrease during the fall and winter months when propane inventories are being drawn for heating needs. In general, our import volumes peak during the spring and summer months and our export volumes are at their highest levels during the winter months.

In support of our commercial goals, our NGL marketing activities rely on inventories of mixed NGLs and purity NGL products. These inventories are the result of accumulated equity NGL production volumes, imports and other spot and contract purchases. Our inventories of ethane, propane and normal butane are typically higher on a seasonal basis from March through November as each are normally in higher demand and at higher price levels during winter months. Isobutane and natural gasoline inventories are generally stable throughout the year. Generally, our inventory cycle begins in late-February to mid-

March (the seasonal low point), builds through September, and remains level until early December before being drawn through winter until the seasonal low is reached again.

Competition. Our natural gas processing business and NGL marketing activities encounter competition from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, and independent processors. Each of our competitors has varying levels of financial and personnel resources, and competition generally revolves around price, service and location.

In the markets served by our NGL pipelines, we compete with a number of intrastate and interstate liquids pipelines companies (including those affiliated with major oil, petrochemical and gas companies) and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees and service.

Our competitors in the NGL and related product storage businesses are integrated major oil companies, chemical companies and other storage and pipeline companies. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections and operational dependability. Our import and export operations also compete with those operated by major oil and chemical companies primarily in terms of loading and offloading volumes per hour.

We compete with a number of NGL fractionators in Texas, Louisiana and Kansas. Although competition for NGL fractionation services is primarily based on the fractionation fee charged, the ability of an NGL fractionator to receive mixed NGLs, store and distribute NGL products is also an important competitive factor and is a function of the existence of the necessary pipeline and storage infrastructure.

Properties. The following table summarizes the significant natural gas processing assets of our NGL Pipelines & Services business segment at February 2, 2009.

Description of Asset	Location(s)	Our Ownership Interest	Net Gas Processing Capacity (Bcf/d) (1)	Total Gas Processing Capacity (Bcf/d)
Natural gas processing facilities:				
Meeker (2)	Colorado	100%	1.40	1.40
Pioneer (3)	Wyoming	100%	1.30	1.30
Toca	Louisiana	67.4%	0.70	1.10
Chaco	New Mexico	100%	0.65	0.65
North Terrebonne	Louisiana	52.5%	0.63	1.30
Calumet	Louisiana	32.7%	0.51	1.60
Neptune	Louisiana	66%	0.43	0.65
Pascagoula	Mississippi	40%	0.40	1.50
Yscloskey	Louisiana	14.6%	0.34	1.85
Thompsonville	Texas	100%	0.30	0.30
Shoup	Texas	100%	0.29	0.29
Gilmore	Texas	100%	0.26	0.26
Armstrong	Texas	100%	0.25	0.25
Others (10 facilities) (4)	Texas, New Mexico, Louisiana	Various (5)	1.19	2.85
Total processing capacities			8.65	15.30

(1) The approximate net natural gas processing capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as volumes processed at the facility and ownership interest in the facility.

(2) We commenced natural gas processing operations at our Meeker facility in October 2007 and subsequently began the Meeker Phase II expansion project to double the natural gas processing capacity to 1.4 Bcf/d at this facility. The Meeker Phase II expansion is expected to be operational during the first quarter of 2009.

(3) Our silica gel natural gas processing facility has a processing capacity of 0.6 Bcf/d. We constructed a new cryogenic processing facility having 0.7 Bcf/d of processing capacity, which became operational in February 2008.

(4) Our other natural gas processing facilities include our Venice, Sea Robin and Burns Point facilities located in Louisiana; Indian Basin and Carlsbad facilities located in New Mexico; and San Martin, Delmita, Sonora, Shilling and Indian Springs facilities located in Texas. Our ownership in the Venice plant is through our 13.1% equity method investment in Venice Energy Services Company, L.L.C. ("VESCO").

(5) Our ownership in these facilities ranges from 13.1% to 100%.

At the core of our natural gas processing business are 24 processing plants located in Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. Our natural gas processing facilities can be characterized as two distinct types: (i) straddle plants situated on mainline natural gas pipelines owned either by us or by third parties or (ii) field plants that process natural gas from gathering pipelines. We operate the Meeker, Pioneer, Toca, Chaco, North Terrebonne, Calumet, Neptune, Burns Point and Carlsbad plants and all of the Texas facilities. On a weighted-average basis, utilization rates for these assets were 66.4%, 66.4%, and 56% during the years ended December 31, 2008, 2007 and 2006, respectively. These rates reflect the periods in which we owned an interest in such facilities.

Our NGL marketing activities utilize a fleet of approximately 730 railcars, the majority of which are leased. These railcars are used to deliver feedstocks to our facilities and to distribute NGLs throughout the United States and parts of Canada. We have rail loading and unloading facilities in Alabama, Arizona, California, Kansas, Louisiana, Minnesota, Mississippi, Nevada, North Carolina and Texas. These facilities service both our rail shipments and those of our customers.

The following table summarizes the significant NGL pipelines and related storage assets of our NGL Pipelines & Services business segment at February 2, 2009.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Useable Storage Capacity (MMBbls)
NGL pipelines:				
Mid-America Pipeline System	Midwest and Western U.S.	100%	7,808	
Dixie Pipeline	South and Southeastern U.S.	100% (1)	1,371	
Seminole Pipeline	Texas	90% (2)	1,342	
Chaparral NGL System (3)	Texas, New Mexico	100%	1,025	
EPD South Texas NGL System	Texas	100% (4)	1,020	
Louisiana Pipeline System	Louisiana	Various (5)	612	
Skelly-Belvieu Pipeline	Texas	49% (6)	570	
Promix NGL Gathering System	Louisiana	50%	364	
DEP South Texas NGL Pipeline System	Texas	100% (4)	297	
Houston Ship Channel	Texas	100%	252	
Lou-Tex NGL	Texas, Louisiana	100%	205	
Others (9 systems) (7)	Various	Various	859	
Total miles			15,725	
NGL and related product storage facilities by state:				
Texas (8)				124.9
Louisiana				15.3
Kansas				7.5
Mississippi				5.7
Others (Arizona, Georgia, Iowa, Kansas, Nebraska, North Carolina, Oklahoma)				4.0
Total capacity (9)				157.4

(1) We acquired the remaining 25.8% ownership interest in this system during August 2008 and now own 100% of the Dixie Pipeline through our subsidiary, Dixie Pipeline Company ("Dixie").
(2) We hold a 90% interest in this system through a majority owned subsidiary, Seminole Pipeline Company ("Seminole").
(3) The Chaparral NGL System includes the 180-mile Quanah Pipeline. The Quanah Pipeline begins in Sutton County, Texas, and connects to the Chaparral Pipeline near Midland, Texas.
(4) Our ownership interest reflects consolidated ownership of these systems by EPO (34%) and Duncan Energy Partners (66%).
(5) Of the 612 total miles for this system, we own 100% of 559 miles and 52.5% of the remaining 53 miles.
(6) Our ownership interest in this pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu"), which we acquired in December 2008.
(7) Includes our Tri-States, Belle Rose, Wilprise, Chunchula, Bay Area and South Dean pipelines located in the coastal regions of Alabama, Louisiana, Mississippi and Texas; Panola and San Jacinto located in East Texas; and our Meeker pipeline in Colorado. We acquired the remaining 16.7% ownership interest in Belle Rose NGL Pipeline, L.L.C. and an additional 16.7% interest in Tri-States NGL Pipeline, L.L.C. in October 2008.
(8) The amount shown for Texas includes 33 underground NGL and petrochemical storage caverns with an aggregate useable storage capacity of approximately 100 MMBbls that we own jointly with Duncan Energy Partners. These caverns are located in Mont Belvieu, Texas.
(9) The 157.4 MMBbls of total useable storage capacity includes 22.4 MMBbls held under long-term operating leases. The leased facilities are located in Texas, Louisiana and Kansas.

The maximum number of barrels that our NGL pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our NGL pipelines cannot be determined. We measure the utilization rates of such pipelines in terms of net throughput (i.e., on a net basis in accordance with our consolidated ownership interest). Total net throughput volumes for these pipelines were 1,948 MBPD, 1,794 MBPD and 1,641 MBPD during the years ended December 31, 2008, 2007 and 2006, respectively.

The following information highlights the general use of each of our principal NGL pipelines. We operate our NGL pipelines with the exception of Skelly-Belvieu Pipeline, Tri-States and a small portion of the Louisiana Pipeline System.

§ The *Mid-America Pipeline System* is a regulated NGL pipeline system consisting of three primary segments: the 2,785-mile Rocky Mountain pipeline, the 2,771-mile Conway North pipeline and the 2,252-mile Conway South pipeline. This system covers thirteen states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin. The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs hub located on the Texas-New Mexico border. During 2007, the Rocky Mountain pipeline's capacity was increased by 50 MBPD. The Conway North segment links the NGL hub at Conway, Kansas to refineries, petrochemical plants and propane markets in the upper Midwest. In addition, the Conway North segment has access to NGL supplies from Canada's Western Sedimentary Basin through third-party connections. The Conway South pipeline, which completed an expansion in 2007, connects the Conway hub with Kansas refineries and transports NGLs to and from Conway, Kansas to the Hobbs hub. The Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionator and storage facility at the Hobbs hub. We also own fifteen unregulated propane terminals that are an integral part of the Mid-America Pipeline System.

  During 2008, approximately 52% of the volumes transported on the Mid-America Pipeline System were mixed NGLs originating from natural gas processing plants located in the Permian Basin in west Texas, the Hugoton Basin of southwestern Kansas, the San Juan Basin of northwest New Mexico, the Piceance Basin of Colorado, the Uintah Basin of Colorado and Utah and the Greater Green River Basin of southwestern Wyoming. The remaining volumes are generally purity NGL products originating from NGL fractionators in the mid-continent areas of Kansas, Oklahoma, and Texas, as well as deliveries from Canada.

§ The *Dixie Pipeline* is a regulated pipeline that extends from southeast Texas and Louisiana to markets in the southeastern United States and transports propane and other NGLs. Propane supplies transported on this system primarily originate from southeast Texas, southern Louisiana and Mississippi. This system operates in seven states: Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina and North Carolina.

§ The *Seminole Pipeline* is a regulated pipeline that transports NGLs from the Hobbs hub and the Permian Basin area of west Texas to markets in southeastern Texas. NGLs originating on the Mid-America Pipeline System are the primary source of throughput for the Seminole Pipeline.

§ The *Chaparral NGL System* is a regulated pipeline that transports NGLs from natural gas processing facilities in West Texas and New Mexico to Mont Belvieu, Texas.

§ The *EPD South Texas NGL System* is a network of NGL gathering and transportation pipelines located in south Texas. The system includes approximately 380 miles of pipeline used to gather and transport mixed NGLs from our south Texas natural gas processing facilities to our south Texas NGL fractionation facilities. The pipeline system also includes approximately 640 miles of pipelines that deliver NGLs from our south Texas fractionation facilities to refineries and petrochemical plants located between Corpus Christi and Houston, Texas and within the Texas City-Houston area, as well as to common carrier NGL pipelines.

We contributed a 66% equity interest in Enterprise GC, LP (“Enterprise GC”), our subsidiary that owns the EPD South Texas NGL Pipeline, to Duncan Energy Partners effective December 8, 2008. We own, through our other subsidiaries, the remaining 34% equity interest in Enterprise GC. For additional information regarding this transaction, see “Other Items – Duncan Energy Partners Transactions” included under Item 7 within this Exhibit 99.1.

§ The *Louisiana Pipeline System* is a network of NGL pipelines located in Louisiana. This system transports NGLs originating in southern Louisiana and in Texas to refineries and petrochemical companies along the Mississippi River corridor in southern Louisiana. This system also provides transportation services for our natural gas processing plants, NGL fractionators and other facilities located in Louisiana.

§ The *Skelly-Belvieu Pipeline* is a regulated pipeline that transports mixed NGLs from Skellytown, Texas to markets in southeast Texas. Volumes originating on the Mid-America Pipeline System and NGLs produced at local refineries are the primary source of throughput for the Skelly-Belvieu Pipeline.

§ The *Promix NGL Gathering System* is a NGL pipeline system that gathers mixed NGLs from natural gas processing plants in Louisiana for delivery to an NGL fractionator owned by K/D/S Promix, L.L.C. (“Promix”). This gathering system is an integral part of the Promix NGL fractionation facility. Our ownership interest in this pipeline is held indirectly through our equity method investment in Promix.

§ The *DEP South Texas NGL Pipeline System* transports NGLs from our Shoup and Armstrong fractionation facilities in south Texas to Mont Belvieu, Texas.

§ The *Houston Ship Channel* pipeline system is a collection of pipelines interconnecting our Mont Belvieu facilities with our Houston Ship Channel import/export terminals and various third party petrochemical plants, refineries and other pipelines located along the Houston Ship Channel. This system is used to deliver NGL products to third-party petrochemical plants and refineries as well as to deliver feedstocks to our Mont Belvieu facilities.

§ The *Lou-Tex NGL* pipeline system is used to provide transportation services for NGLs and refinery grade propylene between the Louisiana and Texas markets. We also use this pipeline to transport mixed NGLs from Mont Belvieu to our Louisiana Pipeline System.

Our NGL and related product storage facilities are integral parts of our pipeline and other operations. In general, these underground storage facilities are used to store NGLs and petrochemical products for us and our customers. We operate these facilities, with the exception of certain Louisiana storage locations operated for us by a third party.

Duncan Energy Partners, one of our consolidated subsidiaries, owns a 66% equity interest in our subsidiary, Mont Belvieu Caverns, LLC (“Mont Belvieu Caverns”). We own, through our other subsidiaries, the remaining 34% equity interest in Mont Belvieu Caverns. Mont Belvieu Caverns owns 34 underground NGL and petrochemical storage caverns with an aggregate storage capacity of approximately 100 MMBbls, a brine system with approximately 20 MMBbls of above-ground brine storage pit capacity and two brine production wells. These assets store and deliver NGLs (such as ethane and propane) and certain refined and petrochemical products for industrial customers located along the upper Texas Gulf Coast.

The following table summarizes the significant NGL fractionation assets of our NGL Pipelines & Services business segment at February 2, 2009.

Description of Asset	Location	Our Ownership Interest	Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:				
Mont Belvieu	Texas	75%	178	230
Shoup and Armstrong	Texas	100% (2)	87	87
Hobbs	Texas	100%	75	75
Norco	Louisiana	100%	75	75
Promix	Louisiana	50%	73	145
BRF	Louisiana	32.2%	19	60
Tebone	Louisiana	52.5%	12	30
Other (3)	Colorado	100%	12	12
Total plant capacities			531	714

(1) The approximate net NGL fractionation capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as volumes processed at the facility and ownership interest in the facility.
(2) Our ownership interest reflects consolidated ownership of these fractionators by EPO (34%) and Duncan Energy Partners (66%).
(3) Consists of two NGL fractionation facilities located in northeast Colorado.

The following information highlights the general use of each of our principal NGL fractionation facilities. We operate all of our NGL fractionation facilities, with the exception of our two Colorado fractionators.

§ Our *Mont Belvieu* NGL fractionation facility is located at Mont Belvieu, Texas, which is a key hub of the domestic and international NGL industry. This facility fractionates mixed NGLs from several major NGL supply basins in North America including the Mid-Continent, Permian Basin, San Juan Basin, Rocky Mountains, East Texas and the Gulf Coast.

§ Our *Shoup* and *Armstrong* NGL fractionation facilities fractionate mixed NGLs supplied by our south Texas natural gas processing plants. In turn, the Shoup and Armstrong facilities supply NGLs transported by the DEP South Texas NGL Pipeline System.

We contributed a 66% equity interest in Enterprise GC, our subsidiary that owns the Shoup and Armstrong NGL fractionators, to Duncan Energy Partners effective December 8, 2008. We own through our other subsidiaries the remaining 34% equity interest in Enterprise GC. For additional information regarding this transaction, see "Other Items – Duncan Energy Partners Transactions" included under Item 7 within this Exhibit 99.1.

§ Our *Hobbs* NGL fractionation facility is located in Gaines County, Texas, where it serves petrochemical end users and refineries in West Texas, New Mexico and California. In addition, the Hobbs facility can supply exports to northern Mexico through existing third-party pipeline infrastructure. The Hobbs facility receives mixed NGLs from several major supply basins including Mid-Continent, Permian Basin, San Juan Basin and the Rocky Mountains. The facility is strategically located at the interconnect of our Mid-America Pipeline System and Seminole Pipeline, providing us flexibility to supply the nation's largest NGL hub at Mont Belvieu, Texas as well as access to the second-largest NGL hub at Conway, Kansas.

§ Our *Norco* NGL fractionation facility receives mixed NGLs via pipeline from refineries and natural gas processing plants located in southern Louisiana and along the Mississippi and Alabama Gulf Coast, including our Yscloskey, Pascagoula, Venice and Toca facilities.

- § The Promix NGL fractionation facility receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast, including our Calumet, Neptune, Burns Point and Pascagoula facilities. In addition to the 364-mile Promix NGL Gathering System, Promix owns five NGL storage caverns and a barge loading facility that are integral to its operations.

- § The *BRF* facility fractionates mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana.

On a weighted-average basis, utilization rates for our NGL fractionators were 82.1%, 76.7% and 71.2% during the years ended December 31, 2008, 2007 and 2006, respectively. These rates reflect the periods in which we owned an interest in such facilities. We own direct consolidated interests in all of our NGL fractionation facilities with the exception of a 50% interest in the facility owned by Promix and a 32.2% interest in the facility owned by Baton Rouge Fractionators LLC ("BRF").

Our NGL operations include import and export facilities located on the Houston Ship Channel in southeast Texas. We own an import and export facility located on land we lease from Oiltanking Houston LP ("OTTI"). Our OTTI import facility can offload NGLs from tanker vessels at rates up to 20,000 barrels per hour depending on the product. Our OTTI export facility can load cargoes of refrigerated propane and butane onto tanker vessels at rates up to 6,700 barrels per hour. In addition to our OTTI facilities, we own a barge dock that can load or offload two barges of NGLs or refinery-grade propylene simultaneously at rates up to 5,000 barrels per hour. Our average combined NGL import and export volumes were 74 MBPD, 84 MBPD and 127 MBPD for the years ended December 31, 2008, 2007 and 2006, respectively.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 18,746 miles of onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. We own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our natural gas marketing activities.

Onshore natural gas pipelines and related natural gas marketing. Our onshore natural gas pipeline systems provide for the gathering and transportation of natural gas from onshore developments, such as the San Juan, Barnett Shale, Permian, Piceance, Greater Green River and Eagle Ford supply basins in the Western U.S., and from offshore developments in the Gulf of Mexico through connections with offshore pipelines. Typically, these systems receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial or municipal customers or to other onshore pipelines.

Certain of our onshore natural gas pipelines generate revenues from transportation agreements where shippers are billed a fee per unit of volume transported (typically in MMBtus) multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Certain of our onshore natural gas pipelines may also offer firm capacity reservation services whereby the shipper pays a contractually stated fee based on the level of capacity reserved in our pipelines whether or not the shipper actually ships the reserved quantity of natural gas. Intrastate natural gas pipelines (such as our Acadian Gas and Alabama Intrastate systems) may also purchase natural gas from producers and suppliers and resell such natural gas to customers such as electric utility companies, local natural gas distribution companies and industrial customers.

We entered the natural gas marketing business in 2001 when we acquired the Acadian Gas System. In 2007, we expanded this marketing business to maximize the utilization of our portfolio of natural gas pipeline and storage assets. Our natural gas marketing activities generate revenues from the sale and delivery of natural gas obtained from (i) third party well-head purchases, (ii) our natural gas processing plants and (iii) the open market. In general, our natural gas sales contracts utilize market-based pricing and can incorporate pricing differentials for factors such as delivery location. We expect our natural gas marketing business to continue to expand in the future. Our consolidated revenues from this business were $3.09 billion, $1.48 billion and $1.10 billion for the years ended December 31, 2008, 2007 and 2006, respectively.

We are exposed to commodity price risk to the extent that we take title to natural gas volumes through our natural gas marketing activities or through certain contracts on our intrastate natural gas pipelines. In addition, our San Juan, Carlsbad and Jonah Gathering Systems and certain segments of our Texas Intrastate System provide aggregating and bundling services, in which we purchase and resell natural gas for certain small producers. Also, several of our gathering systems, while not providing marketing services, have some exposure to risks related to commodity prices through transportation arrangements with shippers. For example, revenues generated by approximately 94% of the natural gas volumes gathered on our San Juan Gathering System are calculated using a percentage of a regional price index for natural gas. We use commodity derivative instruments from time to time to mitigate our exposure to risks related to commodity prices. For information regarding our use of commodity derivative instruments, see "Commodity Risk Hedging Program" included under Item 7A within this Exhibit 99.1.

Underground natural gas storage. We own two underground salt dome natural gas storage facilities located near Hattiesburg, Mississippi that are ideally situated to serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets. On a combined basis, these facilities (our Petal Gas Storage ("Petal") and Hattiesburg Gas Storage ("Hattiesburg") locations) are capable of delivering in excess of 1.4 Bcf/d of natural gas into five interstate pipeline systems. We also lease underground salt dome natural gas storage caverns that serve markets in Texas and Louisiana.

The ability of salt dome storage caverns to handle high levels of injections and withdrawals of natural gas benefits customers who desire the ability to meet load swings and to cover major supply interruption events, such as hurricanes and temporary losses of production. High injection and withdrawal rates also allow customers to take advantage of periods of volatile natural gas prices and respond in situations where they have natural gas imbalance issues on pipelines connected to the storage facilities. Our salt dome storage facilities permit sustained periods of high natural gas deliveries, including the ability to quickly switch from full injection to full withdrawal.

Under our natural gas storage contracts, there are typically two components of revenues: (i) monthly demand payments, which are associated with storage capacity reservation and paid regardless of the customer's usage, and (ii) storage fees per unit of volume stored at our facilities.

Seasonality. Typically, our onshore natural gas pipelines experience higher throughput rates during the summer months as natural gas-fired power generation facilities increase output to meet residential and commercial demand for electricity for air conditioning. Higher throughput rates are also experienced in the winter months as natural gas is needed to fuel residential and commercial heating. Likewise, this seasonality also impacts the timing of injections and withdrawals at our natural gas storage facilities. Producers in the Pinedale field of the Greater Green River supply basin were prohibited from drilling activities typically during November through April due to wildlife restrictions, and accordingly we were limited in our ability to connect new wells to the system during that time. During 2008, the majority of these restrictions were lifted, and as such, the producers in the Pinedale field have fewer drilling restrictions.

Competition. Within their market areas, our onshore natural gas pipelines compete with other onshore natural gas pipelines on the basis of price (in terms of transportation fees and/or natural gas selling prices), service and flexibility. Our competitive position within the onshore market is enhanced by our longstanding relationships with customers and the limited number of delivery pipelines connected (or capable of being economically connected) to the customers we serve.

Competition for natural gas storage is primarily based on location and the ability to deliver natural gas in a timely and reliable manner. Our natural gas storage facilities compete with other providers of natural gas storage, including other salt dome storage facilities and depleted reservoir facilities. We believe that the locations of our natural gas storage facilities allow us to compete effectively with other companies who provide natural gas storage services.

Properties. The following table summarizes the significant assets of our Onshore Natural Gas Pipelines & Services business segment at February 2, 2009.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Approx. Net Capacity, Natural Gas (MMcf/d)	Gross Capacity (Bcf)
Onshore natural gas pipelines:					
Texas Intrastate System	Texas	100% (1)	7,860	5,535	
Jonah Gathering System	Wyoming	100%	714	2,350	
Piceance Basin Gathering System	Colorado	100%	79	1,600	
White River Hub	Colorado	50%	10	1,500	
San Juan Gathering System	New Mexico, Colorado	100%	6,065	1,200	
Acadian Gas System	Louisiana	Various (2)	1,042	1,149	
Val Verde Gas Gathering System	New Mexico, Colorado	100%	400	550	
Carlsbad Gathering System	Texas, New Mexico	100%	919	220	
Alabama Intrastate System	Alabama	100%	408	200	
Encinal Gathering System	Texas	100%	449	143	
Other (6 systems) (3)	Texas, Mississippi	Various (4)	800	460	
Total miles			18,746		
Natural gas storage facilities:					
Petal	Mississippi	100%			16.6
Hattiesburg	Mississippi	100%			2.1
Wilson	Texas	Leased (5)			6.8
Acadian	Louisiana	Leased (6)			1.7
Total gross capacity					27.2

(1) In general, our consolidated ownership of this system is 100% through interests held by EPO and Duncan Energy Partners. We own and operate a 50% undivided interest in the 641-mile Channel pipeline system, which is a component of the Texas Intrastate System. The remaining 50% is owned by affiliates of Energy Transfer Equity. In addition, we own less than a 100% undivided interest in certain segments of the Enterprise Texas pipeline system.
(2) Our ownership interest reflects consolidated ownership of Acadian Gas by EPO (34%) and Duncan Energy Partners (66%). Also includes the 49.5% equity investment that Acadian Gas has in the Evangeline pipeline.
(3) Includes the Delmita, Big Thicket, Indian Springs and Canales gathering systems located in Texas and the Petal and Hattiesburg pipelines located in Mississippi. The Delmita and Big Thicket gathering systems are integral parts of our natural gas processing operations, the results of operations and assets of which are accounted for under our NGL Pipelines & Services business segment. We acquired the Canales gathering system in connection with the Encinal acquisition in July 2006. The Petal and Hattiesburg pipelines are integral components of our natural gas storage operations.
(4) We own 100% of these assets with the exception of the Indian Springs system, in which we own an 80% undivided interest through a consolidated subsidiary. Our 100% interest in Big Thicket reflects consolidated ownership by EPO (34%) and Duncan Energy Partners (66%).
(5) We hold this facility under an operating lease that expires in January 2028.
(6) We hold this facility under an operating lease that expires in December 2012.

On a weighted-average basis, aggregate utilization rates for our onshore natural gas pipelines were approximately 68.7%, 61.6% and 73.7% during the years ended December 31, 2008, 2007 and 2006, respectively. The utilization rate for 2008 excludes the White River Hub, which commenced operations during December 2008 and continues to experience a ramp-up in volumes. The utilization rate for 2007 excludes our Piceance Creek Gathering System, which operated at an average utilization rate of 24.3% during 2007 as volumes ramped-up on this system. Generally, our utilization rates reflect the periods in which we owned an interest in such assets, or, for recently constructed assets, since the dates such assets were placed into service.

The following information highlights the general use of each of our principal onshore natural gas pipelines and storage facilities. We operate our onshore natural gas pipelines and storage facilities with the exception of the White River Hub and small segments of the Texas Intrastate System.

§ The *Texas Intrastate System* gathers and transports natural gas from supply basins in Texas (from both onshore and offshore sources) to local gas distribution companies and electric generation and industrial and municipal consumers as well as to connections with intrastate and interstate pipelines. The Texas Intrastate System is comprised of the 6,547-mile Enterprise Texas pipeline system, the 641-mile Channel pipeline system, the 465-mile Waha gathering system and the 207-mile TPC Offshore gathering system. The leased Wilson natural gas storage facility is an integral part of the Texas Intrastate System. The Enterprise Texas pipeline system includes a 263-mile pipeline we lease from an affiliate of ETP. Collectively, the Texas Intrastate System serves important natural gas producing regions and commercial markets in Texas, including Corpus Christi, the San Antonio/Austin area, the Beaumont/Orange area and the Houston area, including the Houston Ship Channel industrial market.

The 178-mile Sherman Extension of our Texas Intrastate System is scheduled for final completion in March 2009. The Sherman Extension is capable of transporting up to 1.1 Bcf/d of natural gas from the prolific Barnett Shale production basin in North Texas and provides producers with interconnects with third party interstate pipelines having access to markets outside of Texas. Customers, including EPO, have contracted for an aggregate 1.0 Bcf/d of the capacity of the Sherman Extension under long-term contracts.

In late 2008, we began design of the 40-mile Trinity River Basin Extension, which is expected to be completed in two phases in the fourth quarter of 2009 and the second quarter of 2010. The Trinity River Basin Extension will be capable of transporting up to 1.0 Bcf/d of natural gas and will provide producers in the Barnett Shale production basin with additional takeaway capacity. We are also constructing a new storage cavern adjacent to the leased Wilson natural gas storage facility that is expected to be completed in 2010. When completed, this new cavern is expected to provide us with an additional 5.0 Bcf of useable natural gas storage capacity.

We contributed equity interests in our subsidiaries that own the Texas Intrastate System to Duncan Energy Partners effective December 8, 2008. As a result, Duncan Energy Partners owns a 51% voting equity interest in the entity that owns the Enterprise Texas pipeline system, the Channel pipeline system and the Wilson storage facility. Also, Duncan Energy Partners owns a 66% voting equity interest in the entity that owns the Waha gathering system and the TPC Offshore gathering system. We own, through our other subsidiaries, the remaining equity interests in these entities. For additional information regarding this transaction, see “Other Items – Duncan Energy Partners Transactions” included under Item 7 within this Exhibit 99.1.

§ The *Jonah Gathering System* is located in the Greater Green River Basin of southwestern Wyoming. This system gathers natural gas from the Jonah and Pinedale fields for delivery to regional natural gas processing plants, including our Pioneer facility, and major interstate pipelines. We completed the Phase V expansion of the Jonah Gathering System in June 2008. In early 2008, Jonah began an expansion of the portion of its system serving the Pinedale field, which is expected to increase the combined capacity of the system serving the Jonah and Pinedale fields from 2.35 Bcf/d to 2.55 Bcf/d.

§ The *Piceance Basin Gathering System* consists of the 48-mile Piceance Creek and the 31-mile Great Divide gathering systems located in the Piceance Basin of northwestern Colorado. We acquired the Piceance Creek gathering system from EnCana Oil & Gas USA (“EnCana”) in December 2006 and subsequently placed this asset in-service during January 2007. We acquired the Great Divide gathering system from EnCana in December 2008. The Great Divide gathering system gathers natural gas from the southern portion of the Piceance basin, including EnCana’s Mamm Creek field, to our Piceance Creek gathering system. The Piceance Creek gathering system extends from a connection with the Great Divide gathering system to the Meeker facility.

For additional information regarding our acquisition of the Great Divide system, see Note 12 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

§ The *White River Hub* is a FERC-regulated interstate natural gas transportation system designed to provide natural gas transportation and hub services. The White River Hub connects to six interstate natural gas pipelines in northwest Colorado and has a gross capacity of 3.0 Bcf/d of natural gas (1.5 Bcf/d net to our interest). White River Hub began service in December 2008.

§ The *San Juan Gathering System* serves natural gas producers in the San Juan Basin of northern New Mexico and southern Colorado. This system gathers natural gas from production wells located in the San Juan Basin and delivers the natural gas to regional processing facilities, including our Chaco facility.

§ The *Acadian Gas System* purchases, transports, stores and sells natural gas in Louisiana. The Acadian Gas System is comprised of the 577-mile Cypress pipeline, the 438-mile Acadian pipeline and the 27-mile Evangeline pipeline. The leased Acadian natural gas storage facility is an integral part of the Acadian Gas System.

§ The *Val Verde Gas Gathering System* gathers coal bed methane from the Fruitland Coal Formation of the San Juan Basin in northern New Mexico and southern Colorado as well as conventional natural gas. Coal bed methane volumes gathered on the Val Verde system have been in decline. This trend is expected to continue primarily due to the natural decline of coal bed methane production and the maturity of the field.

§ The C*arlsbad Gathering System* gathers natural gas from wells in the Permian Basin region of Texas and New Mexico and delivers natural gas into the El Paso Natural Gas, Transwestern and Oasis pipelines.

§ The *Alabama Intrastate System* mainly gathers coal bed methane from wells in the Black Warrior Basin in Alabama. This system is also involved in the purchase, transportation and sale of natural gas.

§ The *Encinal Gathering System* gathers natural gas from the Olmos and Wilcox formations in south Texas and delivers into our Texas Intrastate System, which delivers the natural gas to our south Texas facilities for processing. We acquired this gathering system in connection with the Encinal acquisition in July 2006.

§ The *Petal* and *Hattiesburg* underground storage facilities are strategically situated to serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets and are capable of delivering in excess of 1.4 Bcf/d of natural gas into five interstate pipeline systems. We placed a new natural gas storage cavern at our Petal facility into service during the third quarter of 2008. The new cavern has a total of 9.1 Bcf of storage capacity which represents 5.9 Bcf of FERC certificated working gas capacity and approximately 3.2 Bcf of base gas requirements needed to support minimum pressures.

Onshore Crude Oil Pipelines & Services

Our Onshore Crude Oil Pipelines & Services business segment includes approximately 4,411 miles of onshore crude oil pipelines and 12.4 MMBbls of storage capacity. This segment also includes our related crude oil marketing activities.

<u>*Onshore crude oil pipelines, terminals and related marketing activities*</u>. We own interests in eight onshore crude oil pipeline systems. Our onshore crude oil pipeline systems gather and transport crude oil primarily in Oklahoma, New Mexico and Texas to refineries, centralized storage terminals and connecting pipelines. Revenue from crude oil transportation is generally based upon a fixed fee per barrel transported

multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers (including those charged internally, which are eliminated in the preparation of our consolidated financial statements). The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC.

We own crude oil terminal facilities in Cushing, Oklahoma and Midland, Texas, which are an integral part of our onshore crude oil operations. In general, our crude oil terminals are used to store crude oil volumes for us and our customers. Under our crude oil terminaling agreements, we charge customers for crude oil storage based on the number of days a customer has volumes in storage multiplied by a storage rate (as defined in each contract). With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for customers at our terminals. The customers pay reservation fees based on the quantity of capacity reserved rather than the actual volumes stored. In addition, we charge our customers throughput (or "pumpover") fees based on volumes withdrawn from our terminals. Lastly, we provide fee-based trade documentation services whereby we document the transfer of title for crude oil volumes transacted between buyers and sellers. Accordingly, the profitability of our crude oil terminaling operations is dependent upon the level of storage capacity reserved by our customers, the volume of product withdrawn from our terminals and the level of fees charged.

Our crude oil marketing activities generate revenues from the sale and delivery of crude oil obtained from producers at the wellhead or through bulk purchases from third parties on the open market at pipelines, terminal facilities and trading locations. These sales contracts generally settle with the physical delivery of crude oil to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location. To limit the exposure of our crude oil marketing activities to price risk, our purchases and sales of crude oil are generally contracted to occur in the same calendar month. In connection with our crude oil marketing activities, we also exchange various grades of crude oil and/or exchange crude oil at different geographic locations to maximize margins or meet contractual delivery requirements.

Seasonality. Our onshore crude oil pipelines and related activities typically exhibit little to no effects of seasonality. However, our onshore pipelines situated along the Texas Gulf Coast may be affected by weather events such as hurricanes and tropical storms.

Competition. In the markets served by our onshore crude oil pipelines, terminals and related marketing activities, we compete with other crude oil pipeline companies, major integrated oil companies and their marketing affiliates, financial institutions with trading platforms and independent crude oil gathering and marketing companies. The onshore crude oil business can be characterized by thin margins and strong competition for supplies of crude oil. Declines in domestic crude oil production have intensified this competition. Competition is based primarily on quality of customer service, competitive pricing and proximity to refineries and other market hubs.

Properties. The following table summarizes the significant crude oil pipelines and related terminal assets of our Onshore Crude Oil Pipelines & Services business segment at February 2, 2009.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Useable Storage Capacity (MMBbls)
Crude oil pipelines:				
Seaway Crude Pipeline System	Texas, Oklahoma	50% (1)	530	5.0
Red River System	Texas, Oklahoma	100%	1,690	1.5
South Texas System	Texas	100%	1,150	1.1
West Texas System	Texas, New Mexico	100%	360	0.4
Other (4 systems) (2)	Texas, Oklahoma, New Mexico	Various	681	0.3
Total miles			4,411	
Crude oil terminals:				
Cushing terminal	Oklahoma	100%		3.1
Midland terminal	Texas	100%		1.0
Total capacity				12.4

(1) Our ownership interest in this pipeline is held indirectly through our equity method investment in Seaway Crude Pipeline Company ("Seaway").
(2) Includes our Azalea, Mesquite and Sharon Ridge crude oil gathering systems and Basin Pipeline System. We own 100% of these assets with the exception of the Basin Pipeline System, in which we own a 13% undivided joint interest.

The maximum number of barrels that our crude oil pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon product composition and demand levels at various delivery points, the exact capacities of our crude oil pipelines cannot be determined. We measure the utilization rates of such pipelines in terms of net throughput (i.e., on a net basis in accordance with our consolidated ownership interest). Total net throughput volumes for these pipelines were 697 MBPD, 646 MBPD and 678 MBPD during the years ended December 31, 2008, 2007 and 2006, respectively.

The following information highlights the general use of each of our principal crude oil pipelines. We operate our crude oil pipelines with the exception of the Basin Pipeline System.

§ The *Seaway Crude Pipeline System* transports imported crude oil from Freeport, Texas to Cushing, Oklahoma and supplies refineries in the Houston area through its terminal facility at Texas City, Texas. The Seaway Crude Pipeline System also has a connection to our South Texas System that allows it to receive both onshore and offshore domestic crude oil in the Texas Gulf Coast area for delivery to Cushing.

§ The *Red River System* is a regulated pipeline that transports crude oil from North Texas to South Oklahoma for delivery to two local refineries or pipeline interconnects for further transportation to Cushing, Oklahoma.

§ The *South Texas System* transports crude oil from an origination point in South Central Texas to the Houston area. The crude oil transported on the South Texas System is delivered to Houston area refineries or pipeline interconnects (including our Seaway Crude Pipeline System) for ultimate delivery to Cushing, Oklahoma.

§ The *West Texas System* connects crude oil gathering systems in West Texas and Southeast New Mexico to our terminal in Midland, Texas.

§ The *Cushing terminal* and *Midland terminal* are strategically located to provide crude oil storage, pumpover and trade documentation services. Our terminal in Cushing, Oklahoma has 19 storage tanks with aggregate crude oil storage capacity of 3.1 MMBbls. The Midland terminal has a storage capacity of 1.0 MMBbls through the use of 12 storage tanks.

Offshore Pipelines & Services

Our Offshore Pipelines & Services business segment includes (i) approximately 1,544 miles of offshore natural gas pipelines strategically located to serve production areas including some of the most active drilling and development regions in the Gulf of Mexico, (ii) approximately 909 miles of offshore Gulf of Mexico crude oil pipeline systems and (iii) six multi-purpose offshore hub platforms located in the Gulf of Mexico with crude oil or natural gas processing capabilities.

Offshore natural gas pipelines. Our offshore natural gas pipeline systems provide for the gathering and transportation of natural gas from production developments located in the Gulf of Mexico, primarily offshore Louisiana and Texas. Typically, these systems receive natural gas from producers, other pipelines and shippers through system interconnects and transport the natural gas to various downstream pipelines, including major interstate transportation pipelines that access multiple markets in the eastern half of the United States.

Our revenues from offshore natural gas pipelines are derived from fee-based agreements and are typically based on transportation fees per unit of volume transported (generally in MMBtus) multiplied by the volume delivered. These transportation agreements tend to be long-term in nature, often involving life-of-reserve commitments with firm and interruptible components. We do not take title to the natural gas volumes that are transported on our natural gas pipeline systems; rather, the shipper retains title and the associated commodity price risk.

Offshore oil pipelines. We own interests in several offshore oil pipeline systems, which are located in the vicinity of oil-producing areas in the Gulf of Mexico. Typically, these systems receive crude oil from offshore production developments, other pipelines or shippers through system interconnects and deliver the crude oil to either onshore locations or to other offshore interconnecting pipelines.

The majority of revenues from our offshore crude oil pipelines are generated based upon a transportation fee per unit of volume (typically in barrels) multiplied by the volume delivered to the customer. A substantial portion of the revenues generated by our offshore crude oil pipeline systems are attributable to long-term transportation agreements with producers. The revenues we earn for our services are dependent on the volume of crude oil to be delivered and the level of fees charged to customers.

Offshore platforms. We have ownership interests in six multi-purpose offshore hub platforms located in the Gulf of Mexico with crude oil and/or natural gas processing capabilities. Offshore platforms are critical components of the energy-related infrastructure in the Gulf of Mexico, supporting drilling and producing operations, and therefore play a key role in the overall development of offshore oil and natural gas reserves. Platforms are used to: (i) interconnect with the offshore pipeline grid; (ii) provide an efficient means to perform pipeline maintenance; (iii) locate compression, separation and production handling and other facilities; (iv) conduct drilling operations during the initial development phase of an oil and natural gas property; and (v) process off-lease production.

Revenues from offshore platform services generally consist of demand payments and commodity charges. Demand fees represent charges to customers served by our offshore platforms regardless of the volume the customer delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand payments and commodity charges, but demand payments generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. Our Independence Hub and Marco Polo offshore platforms earn a significant amount of demand revenues. The Independence Hub platform will earn $54.6 million of demand revenues annually through March 2012. The Marco Polo platform will earn $2.1 million of demand revenues monthly through March 2009.

Seasonality. Our offshore operations exhibit little to no effects of seasonality; however, they may be affected by weather events such as hurricanes and tropical storms in the Gulf of Mexico.

Competition. Within their market areas, our offshore natural gas and oil pipelines compete with other pipelines (both regulated and unregulated systems) primarily on the basis of price (in terms of transportation fees), available capacity and connections to downstream markets. To a limited extent, our competition includes other offshore pipeline systems, built, owned and operated by producers to handle their own production and, as capacity is available, production for others. We compete with other platform service providers on the basis of proximity and access to existing reserves and pipeline systems, as well as costs and rates. Furthermore, our competitors may possess greater capital resources than we have available, which could enable them to address business opportunities more quickly than us.

Properties. The following table summarizes the significant assets of our Offshore Pipelines & Services business segment at February 2, 2009, all of which are located in the Gulf of Mexico primarily offshore Louisiana and Texas.

Description of Asset	Our Ownership Interest	Length (Miles)	Water Depth (Feet)	Approximate Net Capacity Natural Gas (MMcf/d)	Approximate Net Capacity Crude Oil (MPBD)
Offshore natural gas pipelines:					
High Island Offshore System	100%	291		1,800	
Viosca Knoll Gathering System	100%	162		1,000	
Independence Trail	100%	134		1,000	
Green Canyon Laterals	Various (1)	94		605	
Phoenix Gathering System	100%	77		450	
Falcon Natural Gas Pipeline	100%	14		400	
Anaconda Gathering System	100%	137		300	
Manta Ray Offshore Gathering System (2)	25.7%	250		206	
Nautilus System (2)	25.7%	101		154	
VESCO Gathering System (3)	13.1%	260		105	
Nemo Gathering System (4)	33.9%	24		102	
Total miles		1,544			
Offshore crude oil pipelines:					
Cameron Highway Oil Pipeline (5)	50%	374			250
Poseidon Oil Pipeline System (6)	36%	367			144
Allegheny Oil Pipeline	100%	43			140
Marco Polo Oil Pipeline	100%	37			120
Constitution Oil Pipeline	100%	67			80
Typhoon Oil Pipeline	100%	17			80
Tarantula Oil Pipeline	100%	4			30
Total miles		909			
Offshore platforms:					
Independence Hub	80%		8,000	800	NA
Marco Polo (7)	50%		4,300	150	60
Viosca Knoll 817	100%		671	145	5
Garden Banks 72	50%		518	38	18
East Cameron 373	100%		441	195	3
Falcon Nest	100%		389	400	3

(1) Our ownership interests in the Green Canyon Laterals ranges from 2.7% to 100%.
(2) Our ownership interest in these pipelines is held indirectly through our equity method investment in Neptune Pipeline Company, L.L.C. (“Neptune”).
(3) Our ownership interest in this system is held indirectly through our equity method investment in VESCO.
(4) Our ownership interest in this pipeline is held indirectly through our equity method investment in Nemo Gathering Company, LLC (“Nemo”).
(5) Our 50% joint venture ownership interest in this pipeline is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company (“Cameron Highway”).
(6) Our ownership interest in this pipeline is held indirectly through our equity method investment in Poseidon Oil Pipeline Company, LLC (“Poseidon”).
(7) Our 50% joint venture ownership interest in this platform is held indirectly through our equity method investment in Deepwater Gateway, L.L.C. (“Deepwater Gateway”).

We operate our offshore natural gas pipelines, with the exception of the VESCO Gathering System, Manta Ray Offshore Gathering System, Nautilus System, Nemo Gathering System and certain components of the Green Canyon Laterals. On a weighted-average basis, aggregate utilization rates for our offshore natural gas pipelines were approximately 22%, 24.1% and 25.9% during the years ended December 31, 2008, 2007 and 2006, respectively. For recently constructed assets (e.g., Independence Trail), utilization rates reflect the periods since the dates such assets were placed into service.

The following information highlights the general use of each of our principal Gulf of Mexico offshore natural gas pipelines.

§ The *High Island Offshore System* ("HIOS") transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island and East Breaks areas of the Gulf of Mexico to the ANR pipeline system, Tennessee Gas Pipeline and the U-T Offshore System. The HIOS pipeline system includes eight pipeline junction and service platforms. This system also includes the 86-mile East Breaks System that connects HIOS to the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25.

§ The *Viosca Knoll Gathering System* transports natural gas from producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico to several major interstate pipelines, including the Tennessee Gas, Columbia Gulf, Southern Natural, Transco, Dauphin Island Gathering System and Destin Pipelines.

§ The *Independence Trail* natural gas pipeline transports natural gas from our Independence Hub platform to the Tennessee Gas Pipeline. Natural gas transported on the Independence Trail pipeline originates from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico. This pipeline includes one pipeline junction platform at West Delta 68. We completed construction of the Independence Trail natural gas pipeline in 2006 and, in July 2007, the pipeline received its first production from deepwater wells connected to the Independence Hub platform.

§ The *Green Canyon Laterals* consist of 15 pipeline laterals (which are extensions of natural gas pipelines) that transport natural gas to downstream pipelines, including HIOS.

§ The *Phoenix Gathering System* connects the Red Hawk platform located in the Garden Banks area of the Gulf of Mexico to the ANR pipeline system.

§ The *Falcon Natural Gas Pipeline* delivers natural gas processed at our Falcon Nest platform to a connection with the Central Texas Gathering System located on the Brazos Addition Block 133 platform.

§ The *Anaconda Gathering System* connects our Marco Polo platform and the third-party owned Constitution platform to the ANR pipeline system. The Anaconda Gathering System includes our wholly owned Typhoon, Marco Polo and Constitution natural gas pipelines. The Constitution natural gas pipeline serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico.

§ The *Manta Ray Offshore Gathering System* transports natural gas from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico to numerous downstream pipelines, including our Nautilus System.

§ The *Nautilus System* connects our Manta Ray Offshore Gathering System to our Neptune natural gas processing plant on the Louisiana Gulf Coast.

§ The *VESCO Gathering System* is a regulated natural gas pipeline system associated with the Venice natural gas processing plant in Louisiana. This pipeline is an integral part of the natural gas processing operations of VESCO.

- The *Nemo Gathering System* transports natural gas from Green Canyon developments to an interconnect with our Manta Ray Offshore Gathering System.

The following information highlights the general use of each of our principal Gulf of Mexico offshore crude oil pipelines, all of which we operate. On a weighted-average basis, aggregate utilization rates for our offshore crude oil pipelines were approximately 20.1%, 19.3% and 18.1% during the years ended December 31, 2008, 2007 and 2006, respectively.

- The *Cameron Highway Oil Pipeline* gathers crude oil production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas. This pipeline includes one pipeline junction platform.

- The *Poseidon Oil Pipeline System* gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana. This system includes one pipeline junction platform.

- The *Allegheny Oil Pipeline* connects the Allegheny and South Timbalier 316 platforms in the Green Canyon area of the Gulf of Mexico with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

- The *Marco Polo Oil Pipeline* transports crude oil from our Marco Polo platform to an interconnect with our Allegheny Oil Pipeline in Green Canyon Block 164.

- The *Constitution Oil Pipeline* serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico. The Constitution Oil Pipeline connects with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at a pipeline junction platform.

In October 2006, we announced the execution of definitive agreements with producers to construct, own and operate an oil export pipeline (the “Shenzi Oil Pipeline”) that will provide firm gathering services from the BHP Billiton Plc-operated Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico. The Shenzi Oil Pipeline is expected to commence operations during the second quarter of 2009. In August 2008, we, together with Oiltanking Holding Americas, Inc., announced the formation of the Texas Offshore Port System, which was a joint venture to design, construct, operate and own a Texas offshore crude oil port and related pipeline and storage system that would facilitate delivery of waterborne crude oil cargoes to refining centers located along the upper Texas Gulf Coast. For information regarding these projects, see “Liquidity and Capital Resources – Significant Ongoing Growth Capital Projects” included under Item 7 within this Exhibit 99.1.

The following information highlights the general use of each of our principal Gulf of Mexico offshore platforms. We operate these offshore platforms with the exception of the Independence Hub, Marco Polo and East Cameron 373 platforms.

On a weighted-average basis, utilization rates with respect to natural gas processing capacity of our offshore platforms were approximately 36.5%, 28.6% and 17.2% during the years ended December 31, 2008, 2007 and 2006, respectively. Likewise, utilization rates for our offshore platforms were approximately 16.9%, 26.1% and 19.2%, respectively, in connection with platform crude oil processing capacity. For recently constructed assets (e.g., Independence Hub), these rates reflect the periods since the dates such assets were placed into service. In addition to the offshore platforms we identified in the preceding table, we own or have an ownership interest in fourteen pipeline junction and service platforms. Our pipeline junction and service platforms do not have processing capacity.

- The *Independence Hub* platform is located in Mississippi Canyon Block 920. This platform processes natural gas gathered from deepwater production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico. We successfully installed the Independence Hub platform and began earning demand revenues in March 2007. In

July 2007, the Independence Hub platform received first production from deepwater wells connected to the platform.

§ The *Marco Polo* platform, which is located in Green Canyon Block 608, processes crude oil and natural gas from the Marco Polo, K2, K2 North and Genghis Khan fields. These fields are located in the South Green Canyon area of the Gulf of Mexico.

§ The *Viosca Knoll 817* platform is centrally located on our Viosca Knoll Gathering System. This platform primarily serves as a base for gathering deepwater production in the area, including the Ram Powell development.

§ The *Garden Banks 72* platform serves as a base for gathering deepwater production from the Garden Banks Block 161 development and the Garden Banks Block 378 and 158 leases. This platform also serves as a junction platform for our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

§ The *East Cameron 373* platform serves as the host for East Cameron Block 373 production and also processes production from Garden Banks Blocks 108, 152, 197, 200 and 201.

§ The *Falcon Nest* platform, which is located in the Mustang Island Block 103 area of the Gulf of Mexico, currently processes natural gas from the Falcon field.

Petrochemical & Refined Products Services

Our Petrochemical & Refined Products Services business segment consists of (i) propylene fractionation plants and related activities, (ii) butane isomerization facilities, (iii) octane enhancement facility, (iv) refined products pipelines, including our Products Pipeline System, and related activities and (v) marine transportation and other services.

Propylene fractionation and related activities. Our propylene fractionation and related activities consist primarily of two propylene fractionation plants located in Texas and Louisiana, propylene pipeline systems aggregating approximately 787 miles in length and petrochemical marketing activities. This business also includes an above-ground polymer grade propylene storage and export facility located on the Houston Ship Channel.

In general, propylene fractionation plants separate refinery grade propylene (a mixture of propane and propylene) into either polymer grade propylene or chemical grade propylene along with by-products of propane and mixed butane. Polymer grade and chemical grade propylene can also be produced as a by-product of olefin (ethylene) production. The demand for polymer grade propylene primarily relates to the manufacture of polypropylene, which has a variety of end uses, including packaging film, fiber for carpets and upholstery and molded plastic parts for appliance, automotive, houseware and medical products. Chemical grade propylene is a basic petrochemical used in the manufacturing of plastics, synthetic fibers and foams.

Results of operations for our polymer grade propylene plants are generally dependent upon toll processing arrangements and petrochemical marketing activities. These processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation and isomerization operations. The majority of revenues from our propylene pipelines are generated based upon a transportation fee per unit of volume multiplied by the volume delivered to the customer.

Our petrochemical marketing activities generate revenues from the sale and delivery of products obtained through our processing activities and purchases from third parties on the open market. In general, we sell our petrochemical products at market-related prices, which may include pricing differentials for such factors as delivery location.

As part of our petrochemical marketing activities, we have several long-term polymer grade propylene sales agreements. To meet our petrochemical marketing obligations, we have entered into several agreements to purchase refinery grade propylene. To limit the exposure of our petrochemical marketing activities to price risk, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products.

Butane isomerization. Our butane isomerization business includes three butamer reactor units and eight associated deisobutanizer units located in Mont Belvieu, Texas, which comprise the largest commercial isomerization complex in the United States. In addition, this business includes a 70-mile pipeline system used to transport high-purity isobutane from Mont Belvieu, Texas to Port Neches, Texas.

Our commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into isobutane, high purity isobutane and residual normal butane. The primary uses of isobutane are currently for the production of propylene oxide, isooctane and alkylate for motor gasoline. The demand for commercial isomerization services depends upon the industry's requirements for high purity isobutane and isobutane in excess of naturally occurring isobutane produced from NGL fractionation and refinery operations.

The results of operation of this business are generally dependent upon the volume of normal and mixed butanes processed and the level of toll processing fees charged to customers. Our isomerization facility provides processing services to meet the needs of third-party customers and our other businesses, including our NGL marketing activities and octane enhancement production facility.

Octane enhancement. We own and operate an octane enhancement production facility located in Mont Belvieu, Texas designed to produce isooctane, which is an additive used in reformulated motor gasoline blends to increase octane, and isobutylene. The facility produces isooctane and isobutylene using feedstock of high-purity isobutane, which is supplied by our isomerization units. Prior to mid-2005, the facility produced methyl tertiary butyl ether ("MTBE"). We modified the facility to produce isooctane and isobutylene in addition to MTBE. Depending on the outcome of various factors, the facility may be further modified in the future to produce alkylate, another motor gasoline additive.

Refined products pipelines and related activities. Our refined products pipelines and related activities consist primarily of (i) a regulated 4,700-mile products pipeline system and related terminal operations (the "Products Pipeline System") that generally extends in a northeasterly direction from the upper Texas Gulf Coast to the Northeast U.S. and (ii) a 50% joint venture interest in Centennial Pipeline LLC ("Centennial"), which owns a 795-mile refined products pipeline system that extends from the upper Texas Gulf Coast to central Illinois (the "Centennial Pipeline").

The Products Pipeline System transports refined products, and to a lesser extent, petrochemicals such as ethylene and propylene and NGLs such as propane and normal butane. Refined products represent output from refineries and include gasoline, diesel fuel, aviation fuel, kerosene, distillates and heating oil. Refined products also include blend stocks such as raffinate and naphtha. Blend stocks are primarily used to produce gasoline or as a petrochemical plant feedstock. The Centennial Pipeline intersects our Products Pipeline System near Creal Springs, Illinois, and effectively loops the Products Pipeline System between Beaumont, Texas and southern Illinois. Looping the Products Pipeline System permits effective supply of products to points south of Illinois as well as incremental product supply capacity to midcontinent markets downstream of southern Illinois.

The results of operations from our refined products pipelines and related activities are primarily dependent on the tariffs charged to customers to transport products. The tariffs charged for such services are either contractual or regulated by governmental agencies, including the FERC.

Our refined products pipelines and related activities also include the distribution and marketing operations we provide at our Aberdeen, Mississippi and Boligee, Alabama terminals.

Marine transportation and other services. Our marine transportation business consists of tow boats and tank barges that are used primarily to transport refined products, crude oil, asphalt, condensate, heavy fuel oil and other heated oil products along key inland U.S. waterways. Our marine transportation assets service refineries and storage terminals along the Mississippi, Illinois and Ohio rivers, the Intracoastal Waterway between Texas and Florida and the Tennessee-Tombigbee Waterway system. Other services consist of the distribution of lubrication oils and specialty chemicals and the bulk transportation of fuels by trucks, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region of the U.S.

The results of operations from the marine transportation business, which we entered into in February 2008 upon the acquisition of tow boats, tank barges and related assets from Cenac Towing Co., Inc. and affiliates (collectively, "Cenac"), are dependent upon the level of fees charged to transport cargo. Transportation services are generally provided under term contracts (also referred to as affreightment contracts), which are agreements with specific customers to transport cargo from within designated operating areas at set day rates or a set fee per cargo movement.

The results of operations from the distribution of lubrication oils and specialty chemicals and the bulk transportation of fuels are dependent on the sales price or transportation fees that we charge our customers.

Seasonality. Overall, the propylene fractionation business exhibits little seasonality. Our isomerization operations experience slightly higher demand in the spring and summer months due to the demand for isobutane-based fuel additives used in the production of motor gasoline. Likewise, isooctane prices have been stronger during the April to September period of each year, which corresponds with the summer driving season.

Our refined products pipelines and related activities exhibit seasonality based upon the mix of products delivered and the weather and economic conditions in the geographic areas being served. Refined products volumes are generally higher during the second and third quarters because of greater demand for gasoline during the spring and summer driving seasons. NGL transportation volumes are generally higher from November through March due to higher demand for propane for residential heating and for normal butane for blending in motor gasoline.

Our marine transportation business exhibits some seasonal variation. Demand for gasoline and asphalt is generally stronger in the spring and summer months due to the summer driving season and when weather allows for efficient road construction. Weather events, such as hurricanes and tropical storms entering in the Gulf of Mexico, can adversely impact both the offshore and inland businesses. Generally during the winter months, cold weather and ice can negatively impact the inland operations on the upper Mississippi and Illinois rivers.

Competition. We compete with numerous producers of polymer grade propylene, which include many of the major refiners and petrochemical companies located along the Gulf Coast. Generally, the propylene fractionation business competes in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from fully integrated oil companies and various petrochemical companies. Our petrochemical marketing competitors have varying levels of financial and personnel resources and competition generally revolves around price, service, logistics and location.

With respect to our isomerization operations, we compete primarily with facilities located in Kansas, Louisiana and New Mexico. Competitive factors affecting this business include the level of toll processing fees charged, the quality of isobutane that can be produced and access to pipeline and storage infrastructure. We compete with other octane additive manufacturing companies primarily on the basis of price.

The Products Pipeline System's most significant competitors (other than indigenous production in its markets) are third party pipelines in the areas where it delivers products. Competition among common carrier pipelines is based primarily on transportation fees, customer service and proximity to end users. Trucks, barges and railroads competitively deliver products into some of the areas served by our Products Pipeline System and river terminals. The Products Pipeline System faces competition from rail and pipeline movements of NGLs from Canada and waterborne imports into terminals located along the upper East Coast.

Our marine transportation business competes with inland marine transportation companies as well as providers of other modes of transportation, such as rail tank cars, tractor-trailer tank trucks and, to a limited extent, pipelines. Competition within the marine transportation business is based largely on price.

Properties. The following table summarizes the significant propylene, isomerization, petrochemical pipelines and octane additive assets of our Petrochemical & Refined Products Services segment at February 2, 2009, all of which we operate.

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)	Length (Miles)
Propylene fractionation facilities:					
Mont Belvieu (six units)	Texas	Various (1)	73	87	
BRPC	Louisiana	30% (2)	7	23	
Total capacity			80	110	
Isomerization facility:					
Mont Belvieu (3)	Texas	100%	116	116	
Petrochemical pipelines:					
Lou-Tex and Sabine Propylene	Texas, Louisiana	100% (4)			284
North Dean Pipeline System	Texas	100%			138
Texas City RGP Gathering System	Texas	100%			86
Lake Charles	Texas, Louisiana	50%			81
Others (5 systems) (5)	Texas	Various (6)			198
Total miles					787
Octane enhancement production facilities:					
Mont Belvieu (7)	Texas	100%	12	12	

(1) We own a 54.6% interest and lease the remaining 45.4% of a unit having 17 MBPD of plant capacity. We own a 66.7% interest in three additional units having an aggregate 41 MBPD of total plant capacity. We own 100% of the remaining two units, which have 14 MBPD and 15 MBPD of plant capacity, respectively.
(2) Our ownership interest in this facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator LLC ("BRPC").
(3) On a weighted-average basis, utilization rates for this facility were approximately 74.1%, 77.6% and 69.8% during the years ended December 31, 2008, 2007 and 2006, respectively.
(4) Reflects consolidated ownership of these pipelines by EPO (34%) and Duncan Energy Partners (66%).
(5) Includes our Texas City PGP Delivery System and Port Neches, La Porte, Port Arthur and Bayport petrochemical pipelines.
(6) We own 100% of these pipelines with the exception of the 17-mile La Porte pipeline, in which we hold an aggregate 50% indirect interest through our equity method investments in La Porte Pipeline Company L.P. and La Porte Pipeline GP, L.L.C.
(7) On a weighted-average basis, utilization rates for this facility were approximately 58.3% during each of the years ended December 31, 2008, 2007 and 2006, respectively.

We produce polymer grade propylene at our Mont Belvieu location and chemical grade propylene at our BRPC facility. The primary purpose of the BRPC unit is to fractionate refinery grade propylene produced by an affiliate of Exxon Mobil Corporation into chemical grade propylene. The production of polymer grade propylene from our Mont Belvieu facility is primarily used in our petrochemical marketing activities. On a weighted-average basis, aggregate utilization rates of our propylene fractionation facilities were approximately 72.2%, 86% and 86.2% during the years ended December 31, 2008, 2007 and 2006, respectively. This business segment also includes an above-ground polymer grade propylene storage and export facility located in Seabrook, Texas. This facility can load vessels at rates up to 5,000 barrels per hour.

The Lou-Tex Propylene pipeline is used to transport chemical grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas. The Sabine pipeline is used to transport polymer grade propylene from Port Arthur, Texas to a pipeline interconnect in Cameron Parish, Louisiana. The North Dean Pipeline System transports refinery grade propylene from Mont Belvieu, Texas, to Point Comfort, Texas.

The maximum number of barrels that our petrochemical pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our petrochemical pipelines cannot be determined. We measure the utilization rates of such pipelines in terms of net throughput (i.e., on a net basis in accordance with our ownership interest). Total net throughput volumes for these pipelines were 116 MBPD, 114 MBPD and 105 MBPD during the years ended December 31, 2008, 2007 and 2006, respectively.

The following table summarizes the significant refined products pipelines and related storage assets of our Petrochemical & Refined Products Services business segment at February 2, 2009.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Useable Storage Capacity (MMBbls)
Refined products pipelines:				
Products Pipeline System	Texas to Midwest and Northeast U.S.	100%	4,700	
Centennial Pipeline	Texas to central Illinois	50% (1)	795	
Total miles			5,495	
Refined products storage facilities:				
Products Pipeline System (2)	Texas to Midwest and Northeast U.S.	100%		27.0
Centennial Pipeline	Illinois	50% (1)		2.0
Providence terminal (3)	Providence, Rhode Island	100%		0.4
River terminals	Alabama, Mississippi	100%		0.6
Total capacity				30.0

(1) Our ownership interest in this pipeline is held indirectly through our equity method investment in Centennial.
(2) The Products Pipeline System includes 21 MMBbls of refined products storage and 6 MMBbls of NGL storage.
(3) Represents a propane receiving terminal that includes a refrigerated storage tank along with ship unloading and truck loading facilities. We operate the terminal and provide propane loading services to one customer.

The maximum number of barrels that our refined products pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our liquids pipelines cannot be determined. We measure the utilization rates of such pipelines in terms of net throughput (i.e., on a net basis in accordance with its consolidated ownership interest). Total net throughput volumes were as follows for the periods presented:

	For the Year Ended December 31,		
	2008	2007	2006
Refined products transportation (MBPD)	492	542	496
Petrochemical transportation (MBPD)	104	111	81
NGLs transportation (MBPD)	106	115	124

The following information highlights the general use of each of our principal refined products pipelines and related assets.

§ The *Products Pipeline System* is a regulated pipeline system that transports refined products, petrochemicals and NGLs. This pipeline system includes receiving, storage and terminaling facilities and covers twelve states: Texas, Louisiana, Arkansas, Missouri, Illinois, Kentucky, Tennessee, Indiana, Ohio, West Virginia, Pennsylvania and New York. 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 us, connecting pipelines and customer-owned terminals. Petrochemicals are transported on our Products Pipeline System between Mont Belvieu, Texas and Port Arthur, Texas. Our Products Pipeline System transports NGLs from the upper Texas Gulf Coast to the Central, Midwest and Northeast regions of the United States and is the only pipeline that transports NGLs from the upper Texas Gulf Coast to the Northeast. The Centennial Pipeline (see below) effectively loops our Products Pipeline System between Beaumont, Texas and southern Illinois.

In December 2006, we signed an agreement with Motiva Enterprises, LLC ("Motiva") for us to construct and operate a new refined products storage facility to support the expansion of Motiva's refinery in Port Arthur, Texas. Under the terms of the agreement, we are constructing 20 storage tanks with a capacity of 5.4 MMBbls for gasoline and distillates, five 5.4-mile product pipelines connecting the storage facility to Motiva's refinery and distribution pipeline connections to the Colonial, Explorer and Magtex pipelines. As a part of a separate but complementary initiative, we are constructing an 11-mile pipeline to connect the new storage facility in Port Arthur to our refined products terminal in Beaumont, Texas.

§ *Centennial Pipeline* is a regulated refined products pipeline system that covers six states: Texas, Louisiana, Mississippi, Tennessee, Kentucky and Illinois. The Centennial Pipeline extends from an origination facility located on our Products Pipeline System in Beaumont, Texas, to Bourbon, Illinois. Centennial owns a 2.0 MMBbl refined products storage terminal located near Creal Springs, Illinois.

§ We conduct distribution, marketing and terminalling services at our Aberdeen and Boligee *River Terminals*. The Aberdeen terminal, located along the Tennessee-Tombigbee Waterway system in Aberdeen, Mississippi, has storage capacity of 0.1 MMBbls for gasoline and diesel, which are supplied by barge for delivery to local markets, including Tupelo and Columbus, Mississippi. In August 2008, we commenced operations at a 0.5 MMBbl refined products terminal in Boligee in Greene County, Alabama. Located along the Tennessee-Tombigbee waterway system, the facility provides gasoline, diesel and ethanol storage capabilities and provides for direct access to most U.S. Gulf Coast refining centers through an interconnect with the Colonial pipeline system. Additionally, the intermodal terminal offers truck and marine transportation options and future rail capabilities. The facility also serves as an origination point for refined products delivered to our Aberdeen terminal.

The following table summarizes the significant marine transportation assets of our Petrochemical & Refined Products Services business segment at February 2, 2009.

Class of Equipment	Number in Class	Capacity (bbl)/ Horsepower (hp)
Inland marine transportation assets:		
Barges (includes seven single hull barges)	16	< 25,000 bbl
Barges	89	> 25,000 bbl
Tow boats	22	< 2,000 hp
Tow boats	23	> 2,000 hp
Offshore marine transportation assets:		
Barges (includes three single hull barges)	8	> 20,000 bbl
Tow boats	3	< 2,000 hp
Tow boats	3	> 2,000 hp

Our fleet of marine vessels operated at an average utilization rate of 93% during 2008. Such utilization rate reflects the period since the date we acquired these marine transportation assets.

In connection with our entry in the marine transportation business, we entered into a transitional operating agreement with Cenac for a period of up to two years from the date of the Cenac acquisition. Cenac operates our marine transportation business through their marine and shore-based support employees. Under the transitional operating agreement, we reimburse Cenac for personnel salaries and related employee benefit expenses and certain repairs and maintenance expenses on our equipment, as well as payment of a monthly service fee.

The marine transportation industry uses tow boats as power sources and tank barges for freight capacity. The combination of the power source and freight capacity is called a tow. Our inland tows generally consist of one tow boat paired with up to four tank barges, depending upon the horsepower of the tow boat, the trading territory, waterway conditions, customer requirements and prudent operational considerations. Our offshore tows generally consist of one tow boat and one ocean-certified tank barge. Our marine transportation business is subject to regulation by the U.S. Department of Transportation ("DOT"), Department of Homeland Security, Commerce Department and the U.S. Coast Guard ("USCG") and federal and state laws.

Title to Properties

Our real property holdings fall into two basic categories: (i) parcels that we and our unconsolidated affiliates own in fee (e.g., we own the land upon which our Mont Belvieu NGL fractionator is constructed) and (ii) parcels in which our interests and those of our unconsolidated affiliates are derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which our significant facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We and our unconsolidated affiliates have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material lease, easement, right-of-way, permit or license, and we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses.

Capital Spending

We are committed to the long-term growth and viability of Enterprise Products Partners. Part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected future production increases from areas such as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, the Barnett Shale in North Texas and the deepwater Gulf of Mexico. For a discussion of our capital spending program, see "Liquidity and Capital Resources – Capital Spending" included under Item 7 within this Exhibit 99.1.

Weather-Related Risks

In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. See Note 21 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for more information regarding significant risks and uncertainties.

Regulation

Interstate Pipelines

Liquids Pipelines. Certain of our refined products, crude oil and NGL pipeline systems (collectively referred to as “liquids pipelines”) are interstate common carrier pipelines subject to 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 and terms of service be filed with the FERC and posted publicly.

The ICA permits interested persons to challenge proposed new or changed rates or rules and authorizes the FERC to investigate such changes 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 and related rules that are already in effect and may order a carrier to change them 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.

The Energy Policy Act deems just and reasonable (i.e., deems “grandfathered”) liquids pipeline rates that (i) were in effect for the twelve months preceding enactment and (ii) that had not been subject to complaint, protest or investigation. Some, but not all, of our interstate liquids pipeline rates are considered grandfathered under the Energy Policy Act. 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, the 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%. 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 liquids pipeline industry.

As an alternative to using the indexing methodology, 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. Our Products Pipeline System 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.

Because of the complexity of ratemaking, the lawfulness of any rate is never assured. Prescribed rate methodologies for approving regulated tariff rates may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting higher costs. Changes in the FERC’s methodology for approving rates could adversely affect us. In addition, challenges to our tariff rates could be filed with the FERC and decisions by the FERC in approving our regulated rates could adversely affect our cash flow. We believe the transportation rates currently charged by our interstate common carrier liquids 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 such pipelines.

The Lou-Tex Propylene and Sabine Propylene pipelines are interstate common carrier pipelines regulated under the ICA by the Surface Transportation Board (“STB”). If the STB finds that a carrier’s rates are not just and reasonable or are unduly discriminatory or preferential, it may prescribe a reasonable rate. In determining a reasonable rate, the STB will consider, among other factors, the effect of the rate on the volumes transported by that carrier, the carrier’s revenue needs and the availability of other economic transportation alternatives.

The STB does not need to provide rate relief unless shippers lack effective competitive alternatives. If the STB determines that effective competitive alternatives are not available and a pipeline holds market power, then we may be required to show that our rates are reasonable.

Mid-America Pipeline Company, LLC ("Mid-America") is currently involved in a rate case before the FERC. The case primarily involves shipper protests of rate increases on Mid-America's Conway North pipeline filed on March 31, 2005 and March 31, 2006. A hearing before an Administrative Law Judge began on October 2, 2007 and culminated with an initial decision on September 3, 2008. Briefs on Exceptions were filed October 31, 2008, with Briefs Opposing Exceptions filed on January 8, 2009. The matter is presently pending before the FERC, with a decision expected to be issued in the second half of 2009. We are unable to predict the outcome of this litigation.

Natural Gas Pipelines. Our interstate natural gas pipelines and storage facilities that provide services in interstate commerce are regulated by the FERC under the Natural Gas Act of 1938 ("NGA"). Under the NGA, the rates for service on these interstate facilities must be just and reasonable and not unduly discriminatory. We operate these interstate facilities pursuant to tariffs which set forth rates and terms and conditions of service. These tariffs must be filed with and approved by the FERC pursuant to its regulations and orders. Our tariff rates may be lowered on a prospective basis only by the FERC if it finds, on its own initiative or as a result of challenges to the rates by third parties, that they are unjust, unreasonable or otherwise unlawful. Unless the FERC grants specific authority to charge market-based rates, our rates are derived and charged based on a cost-of-service methodology.

The FERC's authority over companies that provide natural gas pipeline transportation or storage services in interstate commerce also includes: (i) certification, construction, and operation of certain new facilities; (ii) the acquisition, extension, disposition or abandonment of such facilities; (iii) the maintenance of accounts and records; (iv) the initiation, extension and termination of regulated services; and (v) various other matters. The FERC's rules require interstate pipelines and their affiliates to adhere to Standards of Conduct that, among other things, require that transportation employees function independently of marketing employees. The Energy Policy Act of 2005 amended the NGA to add an anti-manipulation provision. Pursuant to that act, the FERC established rules prohibiting energy market manipulation. A violation of these rules may subject us to civil penalties, disgorgement of unjust profits, or appropriate non-monetary remedies imposed by the FERC. In addition, the Energy Policy Act of 2005 amended the NGA and the Natural Gas Policy Act of 1978 ("NGPA") to increase civil and criminal penalties for any violation of the NGA, NGPA and any rules, regulations or orders of the FERC up to $1.0 million per day per violation.

Offshore Pipelines. Our offshore natural gas gathering pipelines and crude oil pipeline systems are subject to federal regulation under the Outer Continental Shelf Lands Act, which requires that all pipelines operating on or across the outer continental shelf provide nondiscriminatory transportation service.

Intrastate Pipelines

Liquids Pipelines. Certain of our pipeline systems operate within a single state and provide intrastate pipeline transportation services. These pipeline systems are subject to various regulations and statutes mandated by state regulatory authorities. Although the applicable state statutes and regulations vary, they generally require that intrastate pipelines publish tariffs setting forth all rates, rules and regulations applying to intrastate service, and generally require that pipeline rates and practices be reasonable and nondiscriminatory. Shippers may also challenge our intrastate tariff rates and practices on our pipelines. Our intrastate liquids pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico, Oklahoma and Texas.

Natural Gas Pipelines. Our intrastate natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. Certain of our intrastate natural gas pipelines are also subject to limited regulation by the FERC under the NGPA because they provide transportation and storage service pursuant to Section 311 of the NGPA and Part 284 of the FERC's regulations. Under Section 311 of the NGPA, an intrastate pipeline company may transport gas for an interstate pipeline or any local distribution company served by an interstate pipeline without becoming subject to the FERC's jurisdiction under the NGA. However, such a pipeline is required to provide these services on an open and nondiscriminatory basis, and to make certain rate and other filings and reports are in compliance with the FERC's regulations. The rates for 311 services may be established by the FERC or the respective state agency, but such rates may not exceed a fair and equitable rate.

In September 2007, the FERC also approved an uncontested settlement establishing our maximum firm and interruptible transportation rates for NGPA Section 311 service on the Enterprise Texas Pipeline. In September 2008, we submitted to the FERC a new proposed Section 311 rate for service on our Sherman Extension pipeline, which rate is presently under review by the FERC. We are required to file another rate petition on or before April 2009 to justify our current rates or establish new rates for NGPA Section 311 service. The Texas Railroad Commission has the authority to regulate the rates and terms of service for our intrastate transportation service in Texas.

In September 2007, the FERC approved an uncontested settlement establishing our maximum firm and interruptible transportation rates for NGPA Section 311 service on the Enterprise Alabama Intrastate Pipeline. We are required to file another rate petition on or before May 2010 to justify our current rates or establish new rates for NGPA Section 311 service. The Alabama Public Service Commission has the authority to regulate the rates and terms of service for our intrastate transportation service in Alabama.

Sales of Natural Gas

We are engaged in natural gas marketing activities. The resale of natural gas in interstate commerce is subject to FERC jurisdiction. However, under current federal rules the price at which we sell natural gas currently is not regulated, insofar as the interstate market is concerned and, for the most part, is not subject to state regulation. Our affiliates that engage in natural gas marketing are considered marketing affiliates of our interstate natural gas pipelines. The FERC's rules require interstate pipelines and their marketing affiliates who sell natural gas in interstate commerce subject to the FERC's jurisdiction to adhere to standards of conduct that, among other things, require that their transportation and marketing employees function independently of each other. Pursuant to the Energy Policy Act of 2005, the FERC has established rules prohibiting energy market manipulation. A violation of these rules may subject us to civil penalties, disgorgement of unjust profits, suspension, loss of authorization to perform such sales or other appropriate non-monetary remedies imposed by the FERC.

The FERC is continually proposing and implementing new rules and regulations affecting segments of the natural gas industry. For example, the FERC recently established rules requiring certain non-interstate pipelines to post daily scheduled volume information and design capacity for certain points, and has also required the annual reporting of gas sales information, in order to increase transparency in natural gas markets. In November 2008, the FERC commenced an inquiry into whether to expand the contract reporting requirements of Section 311 service providers. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing activities; however, we believe that any new regulations will also be applied to other natural gas marketers with whom we compete.

Marine Operations

Maritime Law. The operation of tow boats, barges and marine equipment create maritime obligations involving property, personnel and cargo under the General Maritime Law. These obligations can create risks which are varied and include, among other things, the risk of collision and allision, which may precipitate claims for personal injury, cargo, contract, pollution, third party claims and property damages to vessels and facilities. Routine towage operations can also create risk of personal injury under the Jones Act and General Maritime Law, cargo claims involving the quality of a product and delivery, terminal claims, contractual claims and regulatory issues.

Jones Act. The Jones Act is a federal law that restricts maritime transportation between locations in the United States to vessels built and registered in the United States and owned and manned by United States citizens. As a result of our marine transportation business acquisition on February 1, 2008, we now engage in maritime transportation between locations in the United States, and as such, we are subject to the provisions of the law. As a result, we are responsible for monitoring the ownership of our subsidiary that engages in maritime transportation and for taking any remedial action necessary to insure that no violation of the Jones Act ownership restrictions occurs. The Jones Act also requires that all United States-flag vessels be manned by United States citizens. Foreign-flag seamen generally receive lower wages and benefits than those received by United States citizen seamen. This requirement significantly increases operating costs of United States-flag vessel operations compared to foreign-flag vessel operations. Certain foreign governments subsidize their nations' shipyards. This results in lower shipyard costs both for new vessels and repairs than those paid by United States-flag vessel owners. The USCG and American Bureau of Shipping ("ABS") maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for United States-flag operators than for owners of vessels registered under foreign flags of convenience. Following Hurricane Katrina, and again after Hurricane Rita, emergency suspensions of the Jones Act were effectuated by the United States government. The last suspension ended on October 24, 2005. Future suspensions of the Jones Act or other similar actions could adversely affect our cash flow and ability to make distributions to our unitholders. The Jones Act also provides a remedy in damages for crew members injured in the course and scope of their employment. In certain circumstances, a Jones Act seaman can have dual employers under the borrowed servant doctrine.

Merchant Marine Act of 1936. The Merchant Marine Act of 1936 is a federal law that provides that, upon proclamation by the president of the United States of a national emergency or a threat to the national security, the United States secretary of transportation may requisition or purchase any vessel or other watercraft owned by United States citizens (including us, provided that we are considered a United States citizen for this purpose). If one of our tow boats or barges were purchased or requisitioned by the United States government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, if one of our tow boats is requisitioned or purchased and its associated barge or barges are left idle, we would not be entitled to receive any compensation for the lost revenues resulting from the idled barges. We also would not be entitled to be compensated for any consequential damages we suffer as a result of the requisition or purchase of any of our tow boats or barges.

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 financial position, results of operations and cash flows. 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 financial position, results of operations and cash flows.

We believe our operations are in material compliance with applicable environmental and safety laws and regulations, other than certain matters discussed under Item 3 of our Annual Report on Form 10-K, and that compliance with existing environmental and safety laws and regulations are not expected to have a material adverse effect on our financial position, results of operations and cash flows. Environmental and safety laws and regulations are subject to change. 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.

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 such requirements will not have a material adverse effect on our operations, and the requirements are not expected to be any more burdensome to us than any other similarly situated company.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, at least 17 states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA must consider whether it is required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court's holding in Massachusetts that greenhouse gases fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of greenhouse gas emissions from stationary sources under various Clean Air Act programs, including those that may be used in our operations. 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 demand for our operations, 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 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 there is no assurance that the effect will not be material in the aggregate.

The Environmental Protection Agency ("EPA") has also 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 further 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.

Solid Waste

In our normal operations, 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. In the past, although we utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and other materials may have been disposed of or released. In the future we may be required to remove or remediate these materials.

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.

Pipeline Safety Matters

We are subject to regulation by the U.S. 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. The HLPSA requires any entity that owns or operates pipeline facilities to (i) comply with such regulations, (ii) permit access to and copying of records, (iii) file certain reports and (iv) provide information as required by the Secretary of Transportation. We believe that we are in material compliance with these HLPSA regulations.

We are also 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.

In addition, we are 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 ("HCAs"). HCAs are defined to include populated areas, unusually sensitive environmental areas and commercially navigable waterways. The regulation requires the development and implementation of an Integrity Management Program 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 that adequate preventative and mitigative measures exist and that companies take prompt action to address integrity issues raised by the assessment and analysis. In June 2008, DOT extended its pipeline safety regulations, including Integrity Management requirements, to certain rural onshore hazardous liquid gathering lines and certain rural onshore low-stress hazardous liquid pipelines within a buffer area around "unusually sensitive areas." We have identified our HCA pipeline segments and developed an appropriate Integrity Management Program.

Risk Management Plans

We are subject to the EPA's Risk Management Plan regulations at certain facilities. These regulations are intended to work with the Occupational Safety and Health Act ("OSHA") Process Safety Management regulations (see "Safety Matters" below) to minimize the offsite consequences of catastrophic releases. The regulations 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 believe we are operating in material compliance with our risk management program.

Safety Matters

Certain of our facilities 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.

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 PSM regulations.

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.

Employees

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. For additional information regarding the ASA, see "EPCO ASA" in Note 17 included under Exhibit 99.2 of this Current Report on Form 8-K. As of December 31, 2008, there were approximately 4,500 EPCO personnel who spend all or a portion of their time engaged in our business. Approximately 3,100 of these individuals devote all of their time performing management and operating duties for us. The remaining approximate 1,400 personnel are part of EPCO's shared service organization and spend a portion of their time engaged in our business.

In addition to EPCO employees performing services for us, approximately 450 of Cenac's employees provide services to our marine transportation business under the transitional operating agreement. In August 2009, these individuals became employees of EPCO.

Available Information

As a large accelerated filer, we electronically file certain documents with the U.S. Securities and Exchange Commission ("SEC"). 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. Occasionally, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials 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 (800) SEC-0330. In addition, the SEC maintains an Internet website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC, including us.

We provide electronic access to our periodic and current reports on our Internet website, www.epplp.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 (866) 230-0745 for paper copies of these reports free of charge.

Recast of Item 1A. *Risk Factors*.

An investment in our common units involves certain risks. If any of these risks were to occur, our business, financial position, results of operations and cash flows could be materially adversely affected. In that case, the trading price of our common units could decline and you could lose part or all of your investment.

The following section lists the key current risk factors as of the date of this filing that may have a direct impact on our business, financial position, results of operations and cash flows.

Risks Relating to Our Business

Changes in demand for and production of hydrocarbon products may materially adversely affect our financial position, results of operations and cash flows.

We operate predominantly in the midstream energy sector which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs and crude oil. As such, our financial position, results of operations and cash flows may be materially adversely affected by changes in the prices of these hydrocarbon products and by changes in the relative price levels among these hydrocarbon products. Changes in prices and relative price levels may impact demand for hydrocarbon products, which in turn may impact production, demand and volumes of product for which we provide services. We may also incur credit and price risk to the extent counterparties do not perform in connection with our marketing of natural gas, NGLs and propylene.

In the past, the price of natural gas has been extremely volatile, and we expect this volatility to continue. The New York Mercantile Exchange daily settlement price for natural gas for the prompt month contract in 2006 ranged from a high of $10.63 per MMBtus to a low of $4.20 per MMBtus. In 2007, the same index ranged from a high of $8.64 per MMBtus to a low of $5.38 per MMBtus. In 2008, the same index ranged from a high of $13.58 per MMBtus to a low of $5.29 per MMBtus. From January 1, 2009 through September 30, 2009, the same index ranged from a high of $6.07 per MMBtus to a low of $2.51 per MMBtus.

Generally, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors that are impossible to control. Some of these factors include:

§ the level of domestic production and consumer product demand;

§ the availability of imported oil and natural gas;

§ actions taken by foreign oil and natural gas producing nations;

§ the availability of transportation systems with adequate capacity;

§ the availability of competitive fuels;

§ fluctuating and seasonal demand for oil, natural gas and NGLs;

§ the impact of conservation efforts;

§ the extent of governmental regulation and taxation of production; and

§ the overall economic environment.

We are exposed to natural gas and NGL commodity price risk under certain of our natural gas processing and gathering and NGL fractionation contracts that provide for our fees to be calculated based on a regional natural gas or NGL price index or to be paid in-kind by taking title to natural gas or NGLs. A decrease in natural gas and NGL prices can result in lower margins from these contracts, which may materially adversely affect our financial position, results of operations and cash flows.

Our operating results in one or more geographic regions may also be affected by uncertain or changing economic conditions within that region, such as the challenges that are currently affecting economic conditions in the United States. Volatility in commodity prices may also have an impact on many of our customers, which in turn could have a negative impact on their ability to meet their obligations to us.

With respect to our Petrochemical & Refined Products Services segment, market demand and our revenues from these businesses can be adversely affected by the factors described above with respect to crude oil, natural gas, and NGLs, but demand can also vary based upon the different end uses of the products we transport, market or store. For example:

§ demand for gasoline depends upon market price, prevailing economic conditions, demographic changes in the markets we serve and availability of gasoline produced in refineries located in these markets;

§ demand for distillates is affected by truck and railroad freight, the price of natural gas used by utilities that use distillates as a substitute and usage for agricultural operations;

§ demand for jet fuel depends on prevailing economic conditions and military usage; and

§ propane deliveries are generally sensitive to the weather and meaningful year-to-year variances have occurred and will likely continue to occur.

A decline in the volume of natural gas, NGLs and crude oil delivered to our facilities could adversely affect our financial position, results of operations and cash flows.

Our profitability could be materially impacted by a decline in the volume of natural gas, NGLs and crude oil transported, gathered or processed at our facilities. A material decrease in natural gas or crude oil production or crude oil refining, as a result of depressed commodity prices, a decrease in domestic and international exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and crude oil handled by our facilities and other energy logistic assets.

The crude oil, natural gas and NGLs currently transported, gathered or processed at our facilities originate from existing domestic and international resource basins, which naturally deplete over time. To offset this natural decline, our facilities will need access to production from newly discovered properties that are either being developed or expected to be developed. Exploration and development of new oil and natural gas reserves is capital intensive, particularly offshore in the Gulf of Mexico. Many economic and business factors are beyond our control and can adversely affect the decision by producers to explore for and develop new reserves. These factors could include relatively low oil and natural gas prices, cost and availability of equipment and labor, regulatory changes, capital budget limitations, the lack of available capital or the probability of success in finding hydrocarbons. For example, a sustained decline in the price of natural gas and crude oil could result in a decrease in natural gas and crude oil exploration and development activities in the regions where our facilities and other energy logistic assets are located. This could result in a decrease in volumes to our offshore platforms, natural gas processing plants, natural gas, crude oil and NGL pipelines, and NGL fractionators, which would have a material adverse affect on our financial position, results of operations and cash flows. Additional reserves, if discovered, may not be developed in the near future or at all.

In addition, imported liquefied natural gas ("LNG"), is expected to be a significant component of future natural gas supply to the United States. Much of this increase in LNG supplies is expected to be imported through new LNG facilities to be developed over the next decade. Twelve LNG projects have been approved by the FERC to be constructed in the Gulf Coast region and an additional two LNG projects have been proposed for the region. We cannot predict which, if any, of these new projects will be constructed. We may not realize expected increases in future natural gas supply available to our facilities and pipelines if (i) a significant number of these new projects fail to be developed with their announced capacity, (ii) there are significant delays in such development, (iii) they are built in locations where they are not connected to our assets or (iv) they do not influence sources of supply on our systems. If the expected increase in natural gas supply through imported LNG is not realized, projected natural gas throughput on our pipelines would decline, which could have a material adverse effect on our financial position, results of operations and cash flows.

A decrease in demand for NGL products by the petrochemical, refining or heating industries could materially adversely affect our financial position, results of operations and cash flows.

A decrease in demand for NGL products by the petrochemical, refining or heating industries, whether because of general economic conditions, reduced demand by consumers for the end products made with NGL products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, government regulations affecting prices and production levels of natural gas or the content of motor gasoline or other reasons, could materially adversely affect our financial position, results of operations and cash flows. For example:

Ethane. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. If natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls (and, therefore, the demand for ethane by NGL producers falls), it may be more profitable for natural gas producers to leave the ethane in the natural gas stream to be burned as fuel than to extract the ethane from the mixed NGL stream for sale as an ethylene feedstock.

Propane. The demand for propane as a heating fuel is significantly affected by weather conditions. Unusually warm winters could cause the demand for propane to decline significantly and could cause a significant decline in the volumes of propane that we transport.

Isobutane. A reduction in demand for motor gasoline additives may reduce demand for isobutane. During periods in which the difference in market prices between isobutane and normal butane is low or inventory values are high relative to current prices for normal butane or isobutane, our operating margin from selling isobutane could be reduced.

Propylene. Propylene is sold to petrochemical companies for a variety of uses, principally for the production of polypropylene. Propylene is subject to rapid and material price fluctuations. Any downturn in the domestic or international economy could cause reduced demand for, and an oversupply of propylene, which could cause a reduction in the volumes of propylene that we transport.

We face competition from third parties in our midstream businesses.

Even if crude oil and natural gas reserves exist in the areas accessed by our facilities and are ultimately produced, we may not be chosen by the producers in these areas to gather, transport, process, fractionate, store or otherwise handle the hydrocarbons that are produced. We compete with others, including producers of oil and natural gas, for any such production on the basis of many factors, including but not limited to:

§ geographic proximity to the production;

§ costs of connection;

§ available capacity;

§ rates; and

§ access to markets.

Our refined products, NGL and marine transportation businesses compete with other pipelines and marine transportation companies in the areas they serve. We also compete with trucks and railroads in some of the areas we serve. Substantial new construction of inland marine vessels could create an oversupply and intensify competition for our marine transportation business. 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 such 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 future debt level may limit our flexibility to obtain additional financing and pursue other business opportunities.

As of December 31, 2008, we had approximately $11.56 billion of consolidated debt outstanding including Duncan Energy Partners, which had approximately $484.3 million of consolidated debt outstanding. In addition, at September 30, 2009, after taking into account the exchange offer for TEPPCO notes completed on October 27, 2009, we had approximately $11.94 billion of consolidated debt outstanding, including $54.3 million of senior and junior subordinated notes of TEPPCO and $462.8 million of consolidated debt of Duncan Energy Partners. The amount of our future debt could have significant effects on our operations, including, among other things:

- § a substantial portion of our cash flow, including that of Duncan Energy Partners, 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 common units and capital expenditures;

- § credit rating agencies may view our debt level negatively;

- § covenants contained in our existing and future credit and 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, including possible acquisition opportunities;

- § our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- § 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 public debt indentures currently do not limit the amount of future indebtedness that we can create, incur, assume or guarantee. Although EPO's Multi-Year 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. For information regarding EPO's Multi-Year Revolving Credit Facility, see Note 14 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

EPO's Multi-Year Revolving Credit Facility and each of its indentures for public debt contain conventional financial covenants and other restrictions. For example, we are prohibited from making distributions to our partners if such distributions would cause an event of default or otherwise violate a covenant under EPO's Multi-Year Revolving Credit Facility. In addition, under the terms of our junior subordinated notes, generally, if we elect to defer interest payments thereon, we are restricted from making distributions with respect to our equity securities. A breach of any of these restrictions by us could permit our lenders or noteholders, as applicable, to declare all amounts outstanding under these debt agreements to be immediately due and payable and, in the case of EPO's Multi-Year Revolving Credit Facility, to terminate all commitments to extend further credit.

Our ability to access capital markets to raise capital on favorable terms could 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 assessing capital markets or a reduction in the market price of our common 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 in the future, we might be forced to seek extensions for some of our short-term securities or 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 levels.

In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, EPO entered into a $54.0 million, ten-year, fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). The indenture agreement for this loan contains an acceleration clause whereby if EPO's credit rating by Moody's Investor Services declines below Baa3 in combination with our credit rating at Standard & Poor's declining below BBB-, the $54.0 million principal balance of this loan, together with all accrued and unpaid interest would become immediately due and payable 120 days following such event. If such an event occurred, EPO would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support its obligation under this loan.

A downgrade of our credit ratings could result in our being required to post financial collateral up to the amount of our guaranty of indebtedness of our Centennial joint venture, which was $65.0 million at December 31, 2008 and $61.2 million at September 30, 2009. Further, from time to time we enter into contracts in connection with our commodity and interest rate hedging activities that require the posting of financial collateral, which may be substantial, if our credit were to be downgraded below investment grade.

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities.

Our strategy contemplates growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively and diversifying our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating and/or pursuing, potential joint ventures, stand alone projects or other transactions that we believe will present opportunities to realize synergies, expand our role in the energy infrastructure business and increase our market position.

We will require substantial new capital to finance the future development and acquisition of assets and businesses. Any limitations on our access to capital will impair our ability to execute this strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our initial cost of equity include market conditions, fees we pay to underwriters and other offering costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders.

Recent conditions in the financial markets have limited our ability to access equity and credit markets. Generally, credit has become more expensive and difficult to obtain, and the cost of equity capital has also become more expensive. Some lenders are imposing more stringent credit terms and there may be a general reduction in the amount of credit available in the markets in which we conduct business. Tightening of the credit markets may have a material adverse effect on us by, among other things, decreasing our ability to finance expansion projects or business acquisitions on favorable terms and by the imposition of increasingly restrictive borrowing covenants. In addition, the distribution yields of new equity issued may be at a higher yield than our historical levels, making additional equity issuances more expensive.

We also compete for the types of assets and businesses we have historically purchased or acquired. Increased competition for a limited pool of assets could result in our losing to other bidders more often or acquiring assets at less attractive prices. Either occurrence would limit our ability to fully execute our growth strategy. Our inability to execute our growth strategy may materially adversely affect our ability to maintain or pay higher distributions in the future.

Our variable rate debt and future maturities of fixed-rate, long-term debt make us vulnerable to increases in interest rates. Increases in interest rates could materially adversely affect our business, financial position, results of operation and cash flows.

As of December 31, 2008, we had outstanding $11.56 billion of consolidated debt. Of this amount, approximately $2.08 billion, or 13.6%, was subject to variable interest rates, either as short-term or long-term variable rate debt obligations or as long-term fixed-rate debt converted to variable rates through the use of interest rate swaps. Approximately $217.6 million in 4.93% fixed-rate debt matured in March 2009 and an additional $500.0 million of 4.625% fixed-rate Senior Notes matured in October 2009. We also have $54.0 million of 8.70% fixed-rate debt maturing in March 2010, and $500.0 million of 4.95%

fixed-rate Senior Notes maturing in June 2010. The rate on our December 2008 issuance of $500.0 million of Senior Notes due January 2014 was 9.75%. The rate on our June 2009 issuance of $500.0 million of Senior Notes due August 2012 was 4.6%.

As of September 30, 2009, we had outstanding $11.94 billion of consolidated debt. Of this amount, approximately $2.58 billion, or 14.9%, was subject to variable interest rates, either as short-term or long-term variable rate debt obligations or as long-term fixed-rate debt converted to variable rates through the use of interest rate swaps.

Should interest rates continue at current levels or increase significantly, the amount of cash required to service our debt would increase. As a result, our financial position, results of operations and cash flows, could be materially adversely affected.

From time to time, we may enter into additional interest rate swap arrangements, which could increase our exposure to variable interest rates. As a result, our financial position, results of operations and cash flows could be materially adversely affected by significant increases in interest rates.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular, for yield-based equity investments such as our common units. Any such reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

Operating cash flows from our capital projects may not be immediate.

We have announced and are engaged in several construction projects involving existing and new facilities for which we have expended or will expend significant capital, and our operating cash flow from a particular project may not increase until a period of time after its completion. For instance, if we build a new pipeline or platform or expand an existing facility, the design, construction, development and installation may occur over an extended period of time, and we may not receive any material increase in operating cash flow from that project until a period of time after it is placed in-service. If we experience any 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 growth strategy may adversely affect our results of operations if we do not successfully integrate the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

Our growth strategy includes making accretive acquisitions. As a result, from time to time, we will evaluate and acquire assets and businesses (either ourselves or Duncan Energy Partners may do so) that we believe complement our existing operations. We may be unable to integrate successfully businesses we acquire in the future. We may incur substantial expenses or encounter delays or other problems in connection with our growth strategy that could negatively impact our financial position, results of operations and cash flows.

Moreover, acquisitions and business expansions involve numerous risks, including but not limited to:

§ difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;

§ establishing the internal controls and procedures that we are required to maintain under the Sarbanes-Oxley Act of 2002;

§ managing relationships with new joint venture partners with whom we have not previously partnered;

- § inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including with their markets; and

- § diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, accretion and amortization expenses. As a result, our capitalization and results of operations may change significantly following an acquisition. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our financial position, results of operations and cash flows. In addition, any anticipated benefits of a material acquisition, such as expected cost savings, may not be fully realized, if at all.

Acquisitions that appear to be accretive may nevertheless reduce our cash from operations on a per unit basis.

Even if we make acquisitions that we believe will be accretive, these acquisitions may nevertheless reduce our cash from operations on a per unit basis. Any acquisition involves potential risks, including, among other things:

- § mistaken assumptions about volumes, revenues and costs, including synergies;

- § an inability to integrate successfully the businesses we acquire;

- § decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition;

- § a significant increase in our interest expense or financial leverage if we incur additional debt to finance the acquisition;

- § the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;

- § an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;

- § limitations on rights to indemnity from the seller;

- § mistaken assumptions about the overall costs of equity or debt;

- § the diversion of management's and employees' attention from other business concerns;

- § unforeseen difficulties operating in new product areas or new geographic areas; and

- § customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Our actual construction, development and acquisition costs could exceed forecasted amounts.

We have significant expenditures for the development and construction of midstream energy infrastructure assets, including construction and development projects with significant logistical, technological and staffing challenges. We may not be able to complete our projects at the costs we estimated at the time of each project's initiation or that we currently estimate. For example, material and labor costs associated with our projects in the Rocky Mountains region increased over time due to factors such as higher transportation costs and the availability of construction personnel. Similarly, force majeure events such as hurricanes along the Gulf Coast may cause delays, shortages of skilled labor and additional expenses for these construction and development projects, as were experienced with Hurricanes Gustav and Ike in 2008.

Our construction of new assets is subject to regulatory, environmental, political, legal and economic risks, which may result in delays, increased costs or decreased cash flows.

One of the ways we intend to grow our business is through the construction of new midstream energy assets. The construction of new assets involves numerous operational, regulatory, environmental, political and legal risks beyond our control and may require the expenditure of significant amounts of capital. These potential risks include, among other things, the following:

§ we may be unable to complete construction projects on schedule or at the budgeted cost due to the unavailability of required construction personnel or materials, accidents, weather conditions or an inability to obtain necessary permits;

§ we will not receive any material increases in revenues until the project is completed, even though we may have expended considerable funds during the construction phase, which may be prolonged;

§ we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize;

§ since we are not engaged in the exploration for and development of natural gas reserves, we may not have access to third-party estimates of reserves in an area prior to our constructing facilities in the area. As a result, we may construct facilities in an area where the reserves are materially lower than we anticipate;

§ where we do rely on third-party estimates of reserves in making a decision to construct facilities, these estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating reserves;

§ the completion or success of our project may depend on the completion of a project that we do not control, such as a refinery, that may be subject to numerous of its own potential risks, delays and complexities; and

§ we may be unable to obtain rights-of-way to construct additional pipelines or the cost to do so may be uneconomical.

A materialization of any of these risks could adversely affect our ability to achieve growth in the level of our cash flows or realize benefits from expansion opportunities or construction projects.

Substantially all of the common units in us that are owned by EPCO and its affiliates are pledged as security under EPCO's credit facility. Additionally, all of the member interests in our general partner and all of the common units in us that are owned by Enterprise GP Holdings are pledged under its credit facility. Upon an event of default under either of these credit facilities, a change in ownership or control of us could ultimately result.

An affiliate of EPCO has pledged substantially all of its common units in us as security under its credit facility. EPCO's credit facility contains customary and other events of default relating to defaults of EPCO and certain of its subsidiaries, including certain defaults by us and other affiliates of EPCO. An event of default, followed by a foreclosure on EPCO's pledged collateral, could ultimately result in a change in ownership of us. In addition, the 100% membership interest in our general partner and the 20,740,083 of our common units that are owned by Enterprise GP Holdings after giving effect to the TEPPCO Merger on October 26, 2009 are pledged under Enterprise GP Holdings' credit facility. Enterprise GP Holdings' credit facility contains customary and other events of default. Upon an event of default, the lenders under Enterprise GP Holdings' credit facility could foreclose on Enterprise GP Holdings' assets, which could ultimately result in a change in control of our general partner and a change in the ownership of our units held by Enterprise GP Holdings.

The credit and risk profile of our general partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of the general partner or owners of a general partner may be factors in credit evaluations of a master limited partnership. This is because the general partner can exercise significant influence over the business activities of the partnership, including its cash distribution and acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of the general partner and its 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 their limited partner equity interests in us and Enterprise GP Holdings to service such indebtedness. Any distributions by us and Enterprise GP Holdings to such entities will be made only after satisfying our then current obligations to creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us and our general partner from 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 EPCO or the entities that control our general partner were viewed as substantially lower or more risky than ours.

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 business operations and our operating subsidiaries conduct all of our operations and own all of our operating assets. Our only significant assets are the ownership 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 that cash to us in order to meet our obligations and to allow us to make distributions to our partners. The ability of our subsidiaries and joint ventures to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies. For example, all cash flows from Evangeline are currently used to service its debt.

As of December 31, 2008, we also owned 5,393,100 common units and 37,333,887 Class B units of Duncan Energy Partners (these Class B units automatically converted to common units of Duncan Energy Partners on February 1, 2009), representing approximately 74.1% of its outstanding limited partner units and 100% of its general partner. As of September 30, 2009, we owned common units of Duncan Energy Partners representing approximately 58.2% of its outstanding limited partner units and 100% of its general partner. We also owned noncontrolling interests in subsidiaries of Duncan Energy Partners that held total assets of approximately $4.6 billion and $4.7 billion as of December 31, 2008 and September 30, 2009, respectively. With respect to three subsidiaries of Duncan Energy Partners acquired from us on December 8, 2008 that held approximately $3.5 billion and $3.7 billion of total assets as of December 31, 2008 and September 30, 2009, respectively, Duncan Energy Partners has effective priority rights to specified quarterly distribution amounts ahead of distributions on our retained equity interests in these subsidiaries.

In addition, the charter documents governing our joint ventures typically allow their respective joint venture management committees sole discretion regarding the occurrence and amount of distributions. Some of the joint ventures in which we participate have separate credit agreements that contain various restrictive covenants. Among other things, those covenants may limit or restrict the joint venture's ability to make distributions to us under certain circumstances. Accordingly, our joint ventures may be unable to make distributions to us at current levels if at all.

We may be unable to cause our joint ventures to take or not to take certain actions unless some or all of our joint venture participants agree.

We participate in several joint ventures. Due to the nature of some of these arrangements, each participant in these joint ventures has made substantial investments in the joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features customarily include a corporate governance structure that requires at least a majority-in-interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100%) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business, among others. Thus, without the concurrence of joint venture participants with enough voting interests, we may be unable to cause any of our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of us or the particular joint venture.

Moreover, any joint venture owner may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint venture owners. Any such transaction could result in us being required to partner with different or additional parties.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow and, accordingly, affect the market price of our common units.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. We also operate oil and natural gas facilities located underwater in the Gulf of Mexico, which can involve complexities, such as extreme water pressure. In addition, our marine transportation business is subject to additional risks, including the possibility of marine accidents and spill events. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of our assets and our customers' assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane risk.

If one or more facilities that are owned by us or that deliver oil, natural gas or other products to us are damaged by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of the storage contracts that we are a party to obligate us to indemnify our customers for any damage or injury occurring during the period in which the customers' natural gas is in our possession. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions and, accordingly, adversely affect the market price of our common units.

We believe that EPCO maintains adequate insurance coverage on our behalf, although insurance will not cover many types of interruptions that might occur 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, change in the insurance markets subsequent to the hurricanes in 2005 and 2008 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 behalf of us 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, results of operations and cash flows. 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.

An impairment of goodwill and intangible assets could reduce our earnings.

At December 31, 2008, our balance sheet reflected $2.02 billion of goodwill and $1.18 billion of intangible assets. At September 30, 2009, our balance sheet reflected $2.02 billion of goodwill and $1.09 million of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Generally accepted accounting principles in the United States ("GAAP") require us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners' equity and balance sheet leverage as measured by debt to total capitalization.

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 energy 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. Adverse economic conditions, such as the financial crisis that developed in the fourth quarter of 2008, increase the risk of nonpayment or performance by our hedging counterparties. See Note 7 in our Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for a discussion of our derivative instruments.

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, and our credit procedures and policies may not be adequate to fully eliminate customer credit risk. Further, adverse economic conditions, such as the credit crisis that developed in the fourth quarter of 2008, increase the risk of nonpayment and nonperformance by customers, particularly for customers that are smaller companies. 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, net out agreements and guarantees. However, these procedures and policies do not fully eliminate customer credit risk.

Our primary market areas are located in the Gulf Coast, Southwest, Rocky Mountain, Northeast and Midwest 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. Our revenues are derived from a wide customer base. During 2008, 2007 and 2006, our largest customer was Valero Energy Corporation and its affiliates, which accounted for 11.2%, 8.9% and 9.3%, respectively, of our revenues.

On January 6, 2009, LyondellBasell Industries (“LBI”) announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. LBI accounted for 5.9% of our consolidated revenues during 2008. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. We resolved our outstanding claims with LBI in October 2009 with no gain or loss being recorded in connection with the settlement. We continue to do business with this important customer; however, we continue to manage our credit exposure to LBI.

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 processes and procedures will detect and prevent all violations of our risk management policies, particularly if deception or other intentional misconduct is involved.

Our pipeline integrity program and periodic tank maintenance requirements may impose significant costs and liabilities on us.

The U.S. 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. The majority of the costs to comply with the integrity management rule are associated with pipeline integrity testing and the repairs found to be necessary. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipe determined to be located in "high consequence areas" can have a significant impact on the costs to perform integrity testing and repairs. 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.

In June 2008, the U.S. DOT issued a Final Rule extending its pipeline safety regulations, including integrity management requirements, to certain rural onshore hazardous liquid gathering lines and certain rural onshore low-stress hazardous liquid pipelines within a buffer area around "unusually sensitive areas." The issuance of these new gathering and low-stress pipeline safety regulations, including requirements for integrity management of those pipelines, is likely to increase the operating costs of our pipelines subject to such new requirements.

The American Petroleum Institute Standard 653 ("API 653") is an industry standard for the inspection, repair, alteration and reconstruction of existing storage tanks. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Periodic tank maintenance requirements 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 storage tanks.

Environmental costs and liabilities and changing environmental regulation, including climate change regulation, could affect our results of operations, cash flows and financial condition.

Our operations are subject to extensive federal, state and local regulatory requirements relating to environmental affairs, health and safety, waste management and chemical and petroleum products. Further, we cannot ensure that existing environmental regulations will not be revised or that new regulations, such as regulations designed to reduce the emissions of greenhouse gases, will not be adopted or become applicable to us. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to cleanup and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

We will make expenditures in connection with environmental matters as part of normal capital expenditure programs. However, future environmental law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations, including the handling, manufacture, use, emission or disposal of substances and wastes.

Climate change regulation is one area of potential future environmental law development. Studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases," may be contributing to warming of the Earth's atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases. The U.S. Congress is considering legislation to reduce emissions of greenhouse gases. In addition, at least nine states in the Northeast and five states in the West have developed initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The EPA is separately considering whether it will regulate greenhouse gases as "air pollutants" under the existing federal Clean Air Act.

Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S. or the adoption of regulations by the EPA or analogous state agencies that regulate or restrict emissions of greenhouse gases, including methane or carbon dioxide in areas in which we conduct business, could result in changes to the consumption and demand for natural gas and could have adverse effects on our business, financial position, results of operations and prospects. These changes could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC and the provisions of any final legislation.

Increasingly stringent federal, state and local laws and regulations governing worker health and safety and the manning, construction and operation of marine vessels may significantly affect our marine transportation operations. Many aspects of the marine industry are subject to extensive governmental regulation by the USCG, the DOT, the Department of Homeland Security, the National Transportation Safety Board and the U.S. Customs and Border Protection (“CBP”), and to regulation by private industry organizations such as the ABS. The USCG and the National Transportation Safety Board set safety standards and are authorized to investigate vessel accidents and recommend improved safety standards. The USCG is authorized to inspect vessels at will.

Our marine transportation operations are also subject to state and local laws and regulations that control the discharge of pollutants into the environment or otherwise relate to environmental protection. Compliance with such laws, regulations and standards may require installation of costly equipment or operational changes. Failure to comply with applicable laws and regulations may result in administrative and civil penalties, criminal sanctions or the suspension or termination of our marine operations. Some environmental laws often impose strict liability for remediation of spills and releases of oil and hazardous substances, which could subject us to liability without regard to whether we were negligent or at fault. Under the OPA, owners, operators and bareboat charterers are jointly and severally strictly liable for the discharge of oil within the internal and territorial waters of, and the 200-mile exclusive economic zone around, the United States. Additionally, an oil spill from one of our vessels could result in significant liability, including fines, penalties, criminal liability and costs for natural resource damages. The potential for these releases could increase if we increase our fleet capacity. In addition, most states bordering on a navigable waterway have enacted legislation providing for potentially unlimited liability for the discharge of pollutants within their waters.

Federal, state or local regulatory measures could materially adversely affect our business, results of operations, cash flows and financial condition.

The FERC regulates our interstate natural gas pipelines and natural gas storage facilities under the Natural Gas Act, and interstate NGL and petrochemical pipelines under the ICA. The STB regulates our interstate propylene pipelines. State regulatory agencies regulate our intrastate natural gas and NGL pipelines, intrastate storage facilities and gathering lines.

Under the NGA, the FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services is comprehensive and includes the rates charged for the services, terms and condition of service and certification and construction of new facilities. The FERC requires that our services are provided on a non-discriminatory basis so that all shippers have open access to our pipelines and storage. Pursuant to the FERC’s jurisdiction over interstate gas pipeline rates, existing pipeline rates may be challenged by customer complaint or by the FERC Staff and proposed rate increases may be challenged by protest.

We have interests in natural gas pipeline facilities offshore from Texas and Louisiana. These facilities are subject to regulation by the FERC and other federal agencies, including the Department of Interior, under the Outer Continental Shelf Lands Act, and by the DOT's OPS under the Natural Gas Pipeline Safety Act.

Our intrastate NGL and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas, and by the FERC pursuant to Section 311 of the Natural Gas Policy Act. We also have natural gas underground storage facilities in Louisiana, Mississippi and Texas. Although state regulation is typically less onerous than at the FERC, proposed and existing rates subject to state regulation and the provision of services on a non-discriminatory basis are also subject to challenge by protest and complaint, respectively.

For a general overview of federal, state and local regulation applicable to our assets, see "Regulation" included within Items 1 and 2 of this Exhibit 99.1 of this Current Report on Form 8-K. This regulatory oversight can affect certain aspects of our business and the market for our products and could materially adversely affect our cash flows.

We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could adversely affect our ability to make distributions to unitholders.

The workplaces associated with our facilities are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local governmental authorities and local residents. The failure to comply with OSHA requirements or general industry standards, keep adequate records or monitor occupational exposure to regulated substances could have a material adverse effect on our business, financial position, results of operations and ability to make distributions to unitholders.

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 ICA, as amended, the Energy Policy Act and rules and orders promulgated thereunder, regulates the tariff rates for our interstate common carrier pipeline operations. To be lawful under the ICA, 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. The FERC also can order reparations for overcharges effective two years prior to the date of a complaint. 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 interstate liquids pipelines.   FERC's indexing methodology currently allows a pipeline to increase its rates by a percentage linked to the producer price index for finished goods. As an alternative to using the indexing methodology, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, Market-Based Rates or agreements with all of the pipeline's shippers that the rate is acceptable. 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, or challenges to our application of that methodology, 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 or if the states in which we operate adopt policies imposing more onerous regulation on gathering. Additional rules and legislation pertaining to these matters are considered and adopted from time to time at both state and federal levels. We cannot predict what effect, if any, such regulatory changes and legislation might have on our operations, 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, FERC issued a policy statement permitting the inclusion of an income tax allowance in the cost of service-based rates of a pipeline organized as a tax pass through partnership entity to reflect actual or potential income tax liability on public utility income, if the pipeline proves that the ultimate owner of its interests has an actual or potential income tax liability on such income. The policy statement also provides that whether a pipeline’s owners have such actual or potential income tax liability will be reviewed by FERC on a case-by-case basis. In December 2005, FERC issued its first significant case-specific review of the income tax allowance issue in another pipeline partnership’s rate case. 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, 2005 order were appealed to the United States Court of Appeals for the District of Columbia Circuit (“D.C. Circuit”). The D.C. Circuit denied these appeals in May 2007 and fully upheld FERC’s new tax allowance policy and the application of that policy in the December 2005 order.

In December 2006, FERC issued a new order addressing rates on another pipeline. In the new order, FERC refined its income tax allowance policy, and notably raised a new issue regarding the implication of the policy statement for publicly traded partnerships. It noted that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, which FERC characterized as a “tax savings.” FERC stated that it is concerned that this created an opportunity for those investors to earn an additional return, funded by ratepayers. Responding to this concern, FERC chose to adjust the pipeline’s equity rate of return downward based on the percentage by which the publicly traded partnership’s cash flow exceeded taxable income. This and other proceedings pertaining to the FERC’s income tax allowance policy remain pending.

In April 2008, the FERC issued a Policy Statement in which it declared that it would permit MLPs to be included in rate of return proxy groups for determining rates for services by natural gas and oil pipelines. It also addressed the application to limited partnership pipelines of the FERC’s discounted cash flow methodology for determining rates of return on equity. The FERC applied the new policy to several ongoing proceedings involving other pipelines. The FERC’s rate of return policy remains subject to change.

The ultimate outcome of these proceedings is not certain and could result in changes to FERC’s treatment of income tax allowances in cost of service as well as rates of return, particularly with respect to pipelines organized as partnerships. The outcome of these ongoing proceedings could adversely affect our revenues for any of our rates that are calculated using cost of service rate methodologies.

Our marine transportation business would be adversely affected if we failed to comply with the Jones Act provisions on coastwise trade, or if those provisions were modified, repealed or waived.

We are subject to the Jones Act and other federal laws that restrict maritime transportation between points in the United States to vessels built and registered in the United States and owned and manned by U.S. citizens. We are responsible for monitoring the ownership of our common units and other partnership interests. If we do not comply with these restrictions, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels.

In the past, interest groups have lobbied Congress to repeal the Jones Act to facilitate foreign flag competition for trades and cargoes currently reserved for U.S.-flag vessels under the Jones Act and cargo preference laws. We believe that interest groups may continue efforts to modify or repeal the Jones Act and cargo preference laws currently benefiting U.S.-flag vessels. If these efforts are successful, it could result in increased competition, which could reduce our revenues and cash available for distribution.

The Secretary of the Department of Homeland Security is vested with the authority and discretion to waive the coastwise laws to such extent and upon such terms as he may prescribe whenever he deems that such action is necessary in the interest of national defense. For example, in response to the effects of Hurricanes Katrina and Rita, the Secretary of the Department of Homeland Security waived the coastwise laws generally for the transportation of petroleum products from September 1 to September 19, 2005 and from September 26, 2005 to October 24, 2005. In the past, the Secretary of the Department of Homeland Security has waived the coastwise laws generally for the transportation of petroleum released from the Strategic Petroleum Reserve undertaken in response to circumstances arising from major natural disasters. Any waiver of the coastwise laws, whether in response to natural disasters or otherwise, could result in increased competition from foreign marine vessel operators, which could reduce our revenues and cash available for distribution.

Terrorist attacks aimed at our facilities could adversely affect our business, results of operations, cash flows and financial condition.

Since the September 11, 2001 terrorist attacks on the United States, the United States government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be the future target of terrorist organizations. Any terrorist attack on our facilities, pipelines, marine transportation assets or those of our customers could have a material adverse effect on our business.

We depend on the leadership and involvement of Dan L. Duncan and other key personnel for the success of our businesses.

We depend on the leadership, involvement and services of Dan L. Duncan, the founder of EPCO and the chairman of our general partner and other key personnel. Mr. Duncan has been integral to our success and the success of EPCO due in part to his ability to identify and develop business opportunities, make strategic decisions and attract and retain key personnel. The loss of his leadership and involvement or the services of certain key members of our senior management team could have a material adverse effect on our business, financial position, results of operations, cash flows and market price of our securities.

Our marine transportation business is largely dependent upon Mr. Cenac and one of his affiliated companies.

Effective August 1, 2009, we entered into a two-year consulting agreement with Mr. Cenac and one of his affiliated companies. Mr. Cenac has agreed to supervise the day-to-day operations of our marine transportation business on a part-time basis and, at our request, provide related management and transitional services. The consulting agreement contains noncompetition and nonsolitation provisions, which apply until the expiration of the two-year period following the date of the last service provided under the consulting agreement. The success of our marine transportation business is largely dependent on Mr.

Cenac and his affiliate. The unexpected loss the services provided by Mr. Cenac and his affiliate under the consulting agreement described above could have a material adverse effect on the financial position, results of operations and cash flows of our marine transportation business.

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. Certain of our officers are also officers of EPCO and other affiliates of EPCO. 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 officers and employees allocate their time among us, EPCO and other affiliates of EPCO. These officers and employees face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

We have entered into an ASA that governs business opportunities among entities controlled by EPCO, which includes us and our general partner, Enterprise GP Holdings and its general partner and Duncan Energy Partners and its general partner. For information regarding how business opportunities are handled within the EPCO group of companies, please read Item 13 of our Annual Report on Form 10-K for the year ended December 31, 2008.

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.

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system has had, and may continue to have, an impact on our business and financial condition. We may face significant challenges if conditions in the financial markets revert to those that existed in the fourth quarter of 2008. Our ability to access the capital markets may be severely restricted at a time when we would like, or need, to do so, which could have an adverse impact on our ability to meet capital commitments and achieve the flexibility needed to react to changing economic and business conditions. The credit crisis could have a negative impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, demand for our services and products depends on activity and expenditure levels in the energy industry, which are directly and negatively impacted by depressed oil and gas prices. Also, a decrease in demand for NGLs by the petrochemical and refining industries due to a decrease in demand for their products as a result of general economic conditions would likely impact demand for our services and products. Any of these factors could lead to reduced usage of our pipelines and energy logistics services, which could have a material negative impact on our revenues and prospects.

Risks Relating to Our Partnership Structure

We may issue additional securities without the approval of our common unitholders.

At any time, we may issue an unlimited number of limited partner interests of any type (to parties other than our affiliates) without the approval of our unitholders. Our partnership agreement does not give our common unitholders the right to approve the issuance of equity securities including equity securities ranking senior to our common units. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- § the ownership interest of a unitholder immediately prior to the issuance will decrease;
- § the amount of cash available for distributions on each common unit may decrease;
- § the ratio of taxable income to distributions may increase;
- § the relative voting strength of each previously outstanding common unit may be diminished; and
- § the market price of our common units may decline.

We may not have sufficient cash from operations to pay distributions at the current level following establishment of cash reserves and payments of fees and expenses, including payments to EPGP.

Because distributions on our common units are dependent on the amount of cash we generate, distributions 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 EPGP. These factors include but are not limited to the following:

- § the volume of the 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, including the price of and demand for oil, natural gas and other products we transport, store and market;
- § the level of capital expenditures we make;
- § the restrictions contained in our debt agreements and our debt service requirements;
- § fluctuations in our working capital needs;
- § the weather in our operating areas;
- § the cost of acquisitions, if any; and
- § the amount, if any, of cash reserves established by EPGP in its sole discretion.

In addition, you should be aware that the amount of cash we have available for distribution depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, not solely on profitability, which is affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests may decrease in correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

Cost reimbursements and fees due to EPCO and its affiliates, including our general partner 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 officers and directors of EPGP, for all expenses they incur on our behalf, including allocated overhead. These amounts will include all costs incurred in managing and operating us, including costs for rendering administrative staff and support services to us, and overhead allocated to us by EPCO. The payment of these amounts could adversely affect our ability to pay cash distributions to holders of our units. EPCO has sole discretion to determine the amount of these expenses. In addition, EPCO and its affiliates may provide other services to us for which we will be charged fees as determined by EPCO.

EPGP and its affiliates have limited fiduciary responsibilities to, and conflicts of interest with respect to, our partnership, which may permit it to favor its own interests to your detriment.

The directors and officers of EPGP and its affiliates have duties to manage EPGP in a manner that is beneficial to its members. At the same time, EPGP has duties to manage our partnership in a manner that is beneficial to us. Therefore, EPGP's duties to us may conflict with the duties of its officers and directors to its members. Such conflicts may include, among others, the following:

§ neither our partnership agreement nor any other agreement requires EPGP or EPCO to pursue a business strategy that favors us;

§ decisions of EPGP regarding the amount and timing of asset purchases and sales, cash expenditures, borrowings, issuances of additional units and reserves in any quarter may affect the level of cash available to pay quarterly distributions to unitholders and EPGP;

§ under our partnership agreement, EPGP determines which costs incurred by it and its affiliates are reimbursable by us;

§ EPGP is allowed to resolve any conflicts of interest involving us and EPGP and its affiliates;

§ EPGP is allowed to take into account the interests of parties other than us, such as EPCO, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to unitholders;

§ any resolution of a conflict of interest by EPGP not made in bad faith and that is fair and reasonable to us shall be binding on the partners and shall not be a breach of our partnership agreement;

§ affiliates of EPGP may compete with us in certain circumstances;

§ EPGP has limited its liability and reduced its fiduciary duties and has also restricted the remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. As a result of purchasing our units, you are deemed to consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;

- § we do not have any employees and we rely solely on employees of EPCO and its affiliates;

- § in some instances, EPGP may cause us to borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions;

- § our partnership agreement does not restrict EPGP from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

- § EPGP intends to limit its liability regarding our contractual and other obligations and, in some circumstances, may be entitled to be indemnified by us;

- § EPGP controls the enforcement of obligations owed to us by our general partner and its affiliates; and

- § EPGP decides whether to retain separate counsel, accountants or others to perform services for us.

We have significant business relationships with entities controlled by Dan L. Duncan, including EPCO. For detailed information on these relationships and related transactions with these entities, see Item 13 included within our Annual Report on Form 10-K for the year ended December 31, 2008.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors, which could lower the trading price of our common units. In addition, even if unitholders are dissatisfied, they cannot easily remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect EPGP or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis. The Board of Directors of our general partner, including the independent directors, is chosen by the owners of the general partner and not by the unitholders.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have no practical ability to remove EPGP or its officers or directors. EPGP may not be removed except upon the vote of the holders of at least 60% of our outstanding units voting together as a single class. Because affiliates of EPGP currently own approximately 34% of our outstanding common units, the removal of EPGP as our general partner is highly unlikely without the consent of both EPGP and its affiliates. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by a provision in our partnership agreement stating that any units held by a person that owns 20% or more of any class of our common units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence the manner or direction of our management. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

EPGP has a limited call right that may require common unitholders to sell their units at an undesirable time or price.

If at any time EPGP and its affiliates own 85% or more of the common units then outstanding, EPGP 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 common units held by unaffiliated persons at a price not less than the then current market price. As a result, common unitholders may be required to sell their common 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 common unitholders may not have limited liability if a court finds that limited partner actions constitute control of our business.

Under Delaware law, common unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of limited partners to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business.

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.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. You could have unlimited liability for our obligations if a court or government agency determined that:

- we were conducting business in a state, but had not complied with that particular state's partnership statute; or

- your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constituted "control" of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act"), we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

Our general partner's interest in us and the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner, in accordance with our partnership agreement, may transfer its general partner interest without the consent of unitholders. In addition, our general partner may transfer its general partner interest to a third party in a merger or consolidation or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of Enterprise GP Holdings or its affiliates to transfer their equity interests in our general partner to a third party. The new equity owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and to influence the decisions taken by the board of directors and officers of our general partner.

Tax Risks to Common 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. If the Internal Revenue Service were to treat us as a corporation or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to our common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common 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 Internal Revenue Service ("IRS") on this matter.

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

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to a material amount of entity level taxation. In addition, because of widespread state budget deficits and other reasons, several states (including Texas) are evaluating ways to enhance state-tax collections. For example, with respect to tax reports due on or after January 1, 2008, our operating subsidiaries are subject to the Revised Texas Franchise Tax on the portion of their revenue generated in Texas. Specifically, the Revised Texas Franchise Tax is imposed at a maximum effective rate of 0.7% of the operating subsidiaries' gross revenue that is apportioned to Texas. If any additional state were to impose an entity-level tax upon us or our operating subsidiaries, the cash available for distribution to our common unitholders would be reduced.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof could make it more difficult or impossible to meet the exception, which we refer to as the Qualifying Income Exception, for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. For example, in response to certain recent developments, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704(d) of the Internal Revenue Code. It is possible that these legislative efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. Modifications to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively. We are unable to predict whether any changes will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations are issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contests will be borne by our unitholders and our general partner.

The IRS may adopt positions that differ from the positions we take, even positions taken with advice of counsel. 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 some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will be borne indirectly by our unitholders and our general partner.

Even if our common unitholders do not receive any cash distributions from us, they will be required to pay taxes on their share of our taxable income.

Common unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive any cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability which results from their share of our taxable income.

Tax gain or loss on the disposition of our common units could be different than expected.

If a common unitholder sells its common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder’s tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income a unitholder is allocated for a common unit, which decreased the unitholder’s tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the unitholder’s tax basis in that common unit, even if the price the unitholder receives is less than the unitholder’s original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to a unitholder.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investments in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons, raise issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including individual retirement accounts 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 income tax returns and pay tax on their share of our taxable income.

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

Because we cannot match transferors and transferees of common units, we adopt depreciation and amortization positions that may not conform with all aspects of applicable Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the common unitholder's tax returns.

Our common unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, including state and local income 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. Our common unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, they may be subject to penalties for failure to comply with those requirements. We may own property or conduct business in other states or foreign countries in the future. It is the responsibility of each unitholder to file its own federal, 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.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between EPGP and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional common units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and EPGP. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and EPGP, which may be unfavorable to such unitholders. Moreover, under this methodology, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our intangible assets and a lesser portion allocated to our tangible assets. The IRS may challenge our methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between EPGP and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to the unitholder's tax returns without the benefit of additional deductions.

Recast of Item 6. ***Selected Financial Data.***

The following table presents selected historical consolidated financial data of our partnership. This information has been derived from and should be read in conjunction with the audited supplemental financial statements. Our results of operations for the years ended December 31, 2008, 2007, 2006 and 2005 and financial position at December 31, 2008, 2007, 2006 and 2005 have been recast to reflect the TEPPCO Merger. The inclusion of TEPPCO and TEPPCO GP in our supplemental consolidated financial statements was effective January 1, 2005 since an affiliate of EPCO under common control with us originally acquired ownership interests in TEPPCO GP in February 2005. In addition, information regarding our results of operations and liquidity and capital resources can be found under Item 7 within this Exhibit 99.1. As presented in the table, amounts are in millions (except per unit data).

	For the Year Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
Operating results data: (1)					
Revenues	$ 35,469.6	$ 26,713.8	$ 23,612.1	$ 20,858.3	$ 8,321.2
Income from continuing operations (2)	$ 1,188.9	$ 838.0	$ 786.1	$ 581.6	$ 265.6
Net income	$ 1,188.9	$ 838.0	$ 787.6	$ 577.4	$ 276.4
Net income attributed to Enterprise Products Partners L.P.	$ 954.0	$ 533.6	$ 601.1	$ 419.5	$ 268.3
Earnings per unit:					
Basic and Diluted	$ 1.84	$ 0.95	$ 1.20	$ 0.90	$ 0.84
Other financial data:					
Distributions per common unit (3)	$ 2.0750	$ 1.9475	$ 1.825	$ 1.698	$ 1.540

	As of December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
Financial position data: (1)					
Total assets	$ 24,211.6	$ 22,515.5	$ 19,109.2	$ 17,486.7	$ 11,315.5
Long-term and current maturities of debt (4)	$ 11,637.9	$ 8,771.1	$ 6,898.9	$ 6,358.8	$ 4,281.2
Equity (5)	$ 9,295.9	$ 9,016.5	$ 9,124.8	$ 8,203.8	$ 5,399.8
Total units outstanding (excluding treasury) (5)	441.4	435.3	432.4	389.9	364.8

(1) In general, our historical operating results and financial position have been affected by numerous transactions, including the TEPPCO Merger, which was completed on October 26, 2009 and the GulfTerra Merger, which was completed on September 30, 2004. The TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. The inclusion of TEPPCO and TEPPCO GP in our supplemental consolidated financial statements was effective January 1, 2005 since an affiliate of EPCO under common control with us originally acquired ownership interests in TEPPCO GP in February 2005. The GulfTerra Merger was accounted for using the acquisition method (formerly referred to as the purchase method); therefore, the operating results of these acquired entities are included in our financial results prospectively from the acquisition date.

(2) Amounts presented for the years ended December 31, 2006, 2005 and 2004 are before the cumulative effect of accounting changes.

(3) Distributions per common unit represent declared cash distributions with respect to the four fiscal quarters of each period presented.

(4) In general, the balances of our long-term and current maturities of debt have increased over time as a result of financing all or a portion of acquisitions and other capital spending.

(5) We regularly issue common units through underwritten public offerings and, less frequently, in connection with acquisitions or other transactions. For additional information regarding our equity and unit history, see Note 15 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

Recast of Item 7.

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

For the years ended December 31, 2008, 2007 and 2006.

The following information should be read in conjunction with our supplemental consolidated financial statements and our accompanying notes included under Exhibit 99.2 of this Current Report on Form 8-K. Our discussion and analysis includes the following:

§ Cautionary Note Regarding Forward-Looking Statements.

§ Significant Relationships Referenced in this Discussion and Analysis.

§ Overview of Business.

§ TEPPCO Merger and Basis of Presentation.

§ General Outlook for 2009.

§ Recent Developments – Discusses significant developments during the year ended December 31, 2008 and through March 2, 2009.

§ Results of Operations – Discusses material year-to-year variances in our Statements of Consolidated Operations.

§ Liquidity and Capital Resources – Addresses available sources of liquidity and capital resources and includes a discussion of our capital spending program.

§ Critical Accounting Policies and Estimates.

§ Other Items – Includes information related to contractual obligations, off-balance sheet arrangements, related party transactions, recent accounting pronouncements and other matters.

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
MBPD	= thousand barrels per day
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet

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

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A "Risk Factors" within this Exhibit 99.1. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. Except as required by 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.

Significant Relationships Referenced in this Discussion and Analysis

Unless the context requires otherwise, references to "we," "us," "our," or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries, which now includes TEPPCO Partners L.P. and its general partner.

References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts substantially all of its business.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "DEP." References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to "EPGP" mean Enterprise Products GP, LLC, which is our general partner.

References to "Enterprise GP Holdings" mean Enterprise GP Holdings L.P., a publicly traded limited partnership, the units of which are listed on the NYSE under the ticker symbol "EPE." Enterprise GP Holdings owns EPGP. References to "EPE Holdings" mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries. On October 26, 2009, we completed the mergers with TEPPCO and TEPPCO GP (such related mergers referred to herein individually and together as the "TEPPCO Merger"). See "TEPPCO Merger and Basis of Presentation" included within this Item 7 for additional information regarding the TEPPCO Merger.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). On May 7, 2007, Enterprise GP Holdings acquired noncontrolling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to “Employee Partnerships” mean EPE Unit L.P. (“EPE Unit I”), EPE Unit II, L.P. (“EPE Unit II”), EPE Unit III, L.P. (“EPE Unit III”), Enterprise Unit L.P. (“Enterprise Unit”), EPCO Unit L.P. (“EPCO Unit”), TEPPCO Unit L.P. (“TEPPCO Unit I”), and TEPPCO Unit II L.P. (“TEPPCO Unit II”), collectively, all of which are private company affiliates of EPCO, Inc.

References to “EPCO” mean EPCO, Inc. and its wholly owned private company affiliates, which are related parties to all of the foregoing named entities.

We, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings, EPE Holdings, TEPPCO and TEPPCO GP are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

Overview of Business

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids (“NGLs”), crude oil, refined products and certain petrochemicals. Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol “EPD.”

In connection with the TEPPCO Merger, we revised our business segments. Our reorganized business segments reflect the manner in which these businesses are managed and reviewed by the chief executive officer of our general partner. Under our new business segment structure, we have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We conduct substantially all of our business through EPO. We are owned 98% by our limited partners and 2% by our general partner, EPGP. EPGP is owned 100% by Enterprise GP Holdings.

TEPPCO Merger and Basis of Presentation

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 of our common units for each TEPPCO unit. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. TEPPCO’s units, which had been trading on the NYSE under the ticker symbol TPP, have been delisted and are no longer publicly traded.

A privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

Under the terms of the TEPPCO Merger agreements, Enterprise GP Holdings received 1,331,681 of our common units and an increase in the capital account of EPGP to maintain its 2% general partner interest in us as consideration for 100% of the membership interests of TEPPCO GP. Following the closing of the TEPPCO Merger, affiliates of EPCO owned approximately 31.3% of our outstanding limited partner units, including 3.4% owned by Enterprise GP Holdings.

Since Enterprise Products Partners, TEPPCO and TEPPCO GP are under common control of Mr. Duncan, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. The inclusion of TEPPCO and TEPPCO GP in our supplemental consolidated financial statements was effective January 1, 2005 since an affiliate of EPCO under common control with Enterprise Products Partners originally acquired ownership interests in TEPPCO GP in February 2005.

Our supplemental consolidated financial statements prior to the effective date of the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third party and related party ownership interests in TEPPCO and TEPPCO GP prior to the merger have been reflected as "Former owners of TEPPCO," which is a component of noncontrolling interest.

The supplemental financial statements of TEPPCO and TEPPCO GP were prepared from the separate accounting records maintained by TEPPCO and TEPPCO GP. All intercompany balances and transactions have been eliminated in the preparation of our consolidated financial statements.

As previously noted, the TEPPCO Merger was accounted for as a reorganization of entities under common control. The following information is provided to reconcile total revenues and total gross operating margin for the years ended December 31, 2008, 2007 and 2006, as currently presented, with those we previously presented. There was no change in net income attributable to Enterprise Products Partners L.P. for such periods since net income attributable to TEPPCO and TEPPCO GP was allocated to noncontrolling interests. Additionally, there was no change in our reported earnings per unit for such periods. See "Other Items" included within this Item 7 for information regarding total segment gross operating margin, which is a non-generally accepted accounting principle ("non-GAAP") financial measure of segment performance.

	For Year Ended December 31,		
	2008	2007	2006
Total revenues, as previously reported	$ 21,905.6	$ 16,950.1	$ 13,990.9
Revenues from TEPPCO	13,532.9	9,658.1	9,612.2
Revenues from Jonah Gas Gathering Company ("Jonah") (1)	232.8	204.1	78.5
Eliminations (2)	(201.7)	(98.5)	(69.5)
Total revenues, as currently reported	$ 35,469.6	$ 26,713.8	$ 23,612.1
Total segment gross operating margin, as previously reported	$ 2,057.4	$ 1,492.1	$ 1,362.4
Gross operating margin from TEPPCO	501.0	434.8	398.1
Gross operating margin from Jonah	157.6	125.4	43.5
Eliminations (3)	(107.0)	(87.9)	(33.1)
Total segment gross operating margin, as currently reported	$ 2,609.0	$ 1,964.4	$ 1,770.9

(1) Prior to the TEPPCO Merger, we and TEPPCO were joint venture partners in Jonah. As a result of the TEPPCO Merger, Jonah became a consolidated subsidiary.
(2) Represents the eliminations of revenues between us, TEPPCO and Jonah.
(3) Represents equity earnings from Jonah recorded by us and TEPPCO prior to the merger.

General Outlook for 2009

The current global recession and financial crisis have impacted energy companies generally. The recession and related slowdown in economic activity has reduced demand for energy and related products, which in turn has generally led to significant decreases in the prices of crude oil, natural gas and NGLs. The financial crisis has resulted in the effective insolvency, liquidation or government intervention for a number of financial institutions, investment companies, hedge funds and highly leveraged industrial companies. This has had an adverse impact on the prices of debt and equity securities that has generally increased the cost and limited the availability of debt and equity capital.

Commercial Outlook. In 2008, there was significant volatility in the prices of refined products, crude oil, natural gas and NGLs. For example, the average U.S. retail price of regular conventional gasoline ranged from $4.03 per gallon in mid-2008 to $1.81 per gallon in January 2009 according to the Energy Information Administration ("EIA"); the price of West Texas Intermediate crude oil ranged from a high near $147 per barrel in mid-2008 to $35 per barrel in January 2009; while the price of natural gas at the Henry Hub ranged from a high of over $13.00 per MMBtus in mid-2008 to $5.00 per MMBtus in January 2009. On a composite basis, the average price of NGLs declined from $1.68 per gallon for the third quarter of 2008 to $0.74 per gallon for the fourth quarter of 2008. The decrease in energy commodity prices combined with higher costs of capital have led many crude oil and natural gas producers to reconsider their drilling budgets for 2009. As a midstream energy company, we provide services for producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; feedstocks in petrochemical manufacturing; and in the production of motor gasoline.

The decrease in energy commodity prices has caused many oil and natural gas producers, which include many of our customers, to reduce their drilling budgets in 2009. This has resulted in a substantial reduction in the number of drilling rigs operating in the United States as surveyed by Baker Hughes Incorporated. The U.S. operating rig count decreased from a peak of 2,031 rigs in September 2008 to approximately 1,300 in February 2009. We expect oil and gas producers in our operating areas to reduce their drilling activity to varying degrees, which may lead to lower crude oil, natural gas and NGL production growth in the near term and, as a result, lower transportation, storage, processing and marketing volumes and other services for us than would have otherwise been the case.

In our natural gas processing business, we hedged approximately 80% of our equity NGL production margins for 2008 to mitigate the commodity price risk associated with these volumes. We have hedged approximately 67% of our expected equity NGL production margins for 2009. Since the hedges were consummated at prices that are significantly higher than current levels, we are expected to be partially insulated from lower natural gas processing margins in 2009.

The recession has reduced demand for midstream energy services and products by industrial customers. In the fourth quarter of 2008, the petrochemical industry experienced a dramatic destocking of inventories, which reduced demand for purity NGL products such as ethane, propane and normal butane. We expect that petrochemical demand will strengthen in early 2009 and have starting seeing signs of such demand through February 2009 as petrochemical customers have begun to restock their depleted inventories. This trend is also evidenced by slightly higher operating rates of U.S. ethylene crackers, which averaged approximately 70% of capacity in February 2009 as compared to 56% in December 2008. Four additional ethylene crackers were expected to recommence operations in February 2009. The average utilization rate for ethylene crackers in 2008 was approximately 80%. Based on currently available information, we expect that the operating rates of U.S. ethylene crackers will approximate 80% of capacity in 2009. We expect that crude oil prices will rebound from recent lows in the second half of 2009. As a result, we believe the petrochemical industry will continue to prefer NGL feedstocks over crude-based alternatives such as naphtha. In general, when the price of crude oil rises relative to that of natural gas, NGLs become more attractive as a source of feedstocks for the petrochemical industry.

The recession has also impacted the demand for refined products such as gasoline, diesel and jet fuel. According to EIA statistics, gasoline demand decreased 3.5% for 2008 when compared to 2007. Demand for diesel and jet fuel have also weakened in response to the slowing economy. Many refiners have announced plans to perform major maintenance projects during the first quarter of 2009 in response to weakened demand for their products. This situation will most likely contribute to a decrease in transportation volumes on refined products pipelines. We expect that demand for refined products will remain at current levels until the domestic economy begins to recover from the current recession.

The reduction in near-term demand for crude oil and NGLs has created a contango market (i.e., a market in which the price of a commodity is higher in future months than the current spot price) for these products, which, in turn, we are benefiting from through an increase in revenues earned by our storage assets in Mont Belvieu, Texas and Cushing, Oklahoma.

Liquidity Outlook. Debt and equity capital markets have also experienced significant recent volatility. The major U.S. and international equity market indices experienced significant losses in 2008, including losses of approximately 38% and 34% for the S&P 500 and Dow Jones Industrial Average, respectively. Likewise, the Alerian MLP Index, which is a recognized major index for publicly traded partnerships, lost approximately 42% of its value. The contraction in credit available to and investor redemptions of holdings in certain investment companies and hedge funds exacerbated the selling pressure and volatility in both the debt and equity capital markets. This has resulted in a higher cost of debt and equity capital for the public and private sector. Near term demand for equity securities through follow on offerings, including our common units, may be reduced due to the recent problems encountered by investment companies and hedge funds, both of which significantly participated in equity offerings over the past few years.

While the cost of capital has increased, we have demonstrated our ability to access the debt and equity capital markets during this distressed period. In December 2008, we issued $500.0 million of 9.75% senior notes. The higher cost of capital is evident when you compare the interest rate of the December 2008 senior notes offering to the $400.0 million of 5.65% senior notes that we issued in March 2008. On a positive note, our indicative cost of long-term borrowing has improved approximately 250 basis points in early 2009 in conjunction with the recent improvement in the debt capital markets. We believe that we will be able to either access the capital markets or utilize availability under our long-term multi-year revolving credit facility to refinance our $717.6 million of debt obligations that mature in 2009. In January 2009, we issued approximately 10.6 million of our common units at an effective annual distribution yield of 9.5%. Net proceeds from this offering were $225.6 million and used to reduce borrowings and for general partnership purposes.

The increase in the cost of capital has caused us to prioritize our respective internal growth projects to select those with higher rates of return. However, consistent with our business strategy, we continuously evaluate possible acquisitions of assets that would complement our current operations.   Given the current state of the credit markets, we believe competition for such assets has decreased, which may result in opportunities for us to acquire assets at attractive prices that would be accretive to our partners and expand our portfolio of midstream energy assets.

Based on information currently available, we estimate that our capital spending for property, plant and equipment in 2009 will approximate $1.34 billion, which includes $1.11 billion for growth capital projects and $232.0 million for sustaining capital expenditures. The 2009 forecast amounts for growth capital projects include amounts that are expected to be spent on the Texas Offshore Port System. See “Recent Developments – Texas Offshore Port System” for additional information regarding the Texas Offshore Port System joint venture.

We expect four of our significant construction projects to be completed and the assets placed into service during the first half of 2009. These projects include (i) the expansion of the Meeker natural gas processing plant, which began operations in February 2009, (ii) the Exxon Mobil central treating facility, (iii) the Sherman Extension natural gas pipeline, and (iv) the Shenzi crude oil pipeline in the Gulf of Mexico. Substantially all of the financing to fund these projects has been completed. In 2009, we expect these projects to contribute significant new sources of revenue, operating income and cash flow from operations.

Hurricanes Gustav and Ike damaged a number of energy-related assets onshore and offshore along the Texas and Louisiana Gulf Coast in the summer of 2008, including certain of our offshore pipelines and platforms. Repairs are being completed on our affected assets and they are expected to be ready to return to service once third party production fields return to operational status over the course of 2009.

A few of our customers have experienced severe financial problems leading to a significant impact on their creditworthiness. These financial problems are rooted in various factors including the significant use of debt, current financial crises, economic recession and changes in commodity prices. We are working to implement, to the extent allowable under applicable contracts, tariffs and regulations, prepayments and other security requirements, such as letters of credit, to enhance our respective credit position relating to amounts owed us by certain customers. We cannot provide assurance that one or more of our customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our consolidated financial position, results of operations, or cash flows; however, we believe that we have provided adequate allowances for such customers.

We expect that our proactive approach to funding capital spending and other partnership needs, combined with sufficient trade credit to operate our businesses efficiently, and available borrowing capacity under our credit facilities, will provide us with a foundation to meet our anticipated liquidity and capital requirements in 2009. We believe that we will be able to access the capital markets in 2009 to maintain financial flexibility. Based on information currently available to us, we believe that we will maintain our investment grade credit ratings and meet our loan covenant obligations in 2009.

Recent Developments

The following information highlights our significant developments from January 1, 2008 through March 2, 2009 (the original filing date of our Annual Report on Form 10-K for the year ended December 31, 2008).

Enterprise Products Partners Issues $225.6 million of Common Units

In January 2009, Enterprise Products Partners sold 10,590,000 common units representing limited partner interests (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit. Net offering proceeds of $225.6 million were used to reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

High Island Offshore System Natural Gas Pipeline Resumes Operations

In December 2008, repairs were completed on the High Island Offshore System ("HIOS") pipeline that was severed in September 2008 during Hurricane Ike. Federal regulators, after approving our inspection and start-up procedures, authorized the partnership to resume full service on HIOS. The pipeline has the capacity to transport up to 1.8 Bcf/d of natural gas.

Operations Begin at White River Hub

In December 2008, we and Questar Pipeline Company ("Questar"), a subsidiary of Questar Corp., announced that service had begun on the White River Hub. Located in Rio Blanco County, Colo., the White River Hub currently connects our natural-gas processing plant at Meeker with four interstate natural gas pipelines: Rockies Express Pipeline LLC; Questar; Northwest Pipeline GP (including the Williams Willow Creek processing plant, which is currently under construction); and TransColorado Gas Transmission Company. Two more interstate pipelines, the Wyoming Interstate Company and Colorado Interstate Gas systems, are expected to be connected during the first quarter of 2009.

Sale of Interest in Companies to Duncan Energy Partners

In December 2008, Duncan Energy Partners acquired controlling equity interests in three midstream energy companies from affiliates of EPO in a transaction valued at $730.0 million. Duncan Energy Partners acquired a 51% membership interest in Enterprise Texas Pipeline LLC ("Enterprise Texas"); a 51% general partnership interest in Enterprise Intrastate LP ("Enterprise Intrastate"); and a 66% general partnership interest in Enterprise GC, LP ("Enterprise GC"). In the aggregate, these companies own more than 8,000 miles of natural gas pipelines with 5.6 Bcf/d of capacity; a leased natural gas storage facility with 6.8 Bcf of storage capacity; more than 1,000 miles of NGL pipelines; approximately 18 MMBbls of leased NGL storage capacity; and two NGL fractionators with a combined fractionation capacity of 87 MBPD. All of these assets are located in Texas. As consideration for this dropdown transaction, EPO received 37,333,887 Class B units valued at $449.5 million and $280.5 million in cash from Duncan Energy Partners. The Class B limited partner units automatically converted to common units of Duncan Energy Partners on February 1, 2009. For additional information regarding this transaction, see "Other Items – Duncan Energy Partners Transactions" within this Item 7.

EPO Issues $500.0 Million of Senior Notes

In December 2008, EPO sold $500.0 million in principal amount of 9.75% fixed-rate, unsecured senior notes due January 2014 ("Senior Notes O"). Net proceeds from this offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes. For additional information regarding this issuance of debt, see Note 14 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

EPO Executes $592.6 Million of Credit Facilities

In November 2008, EPO executed two senior unsecured credit facilities that provide the partnership with $592.6 million of incremental borrowing capacity. The facilities are comprised of a $375.0 million credit facility maturing in November 2009 and a 20.7 billion yen (approximately $217.6 million U.S. dollar equivalent) term loan maturing in March 2009. The Japanese term loan has a funded cost of approximately 4.93%, including the cost of related foreign exchange currency swaps. For additional information regarding these issuances of debt, see Note 14 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

TEPPCO Issues $257.0 Million of Units

In September 2008, TEPPCO sold 9,200,000 units representing limited partner interests (including an over-allotment of 1,200,000 units) to the public at an offering price of $29.00 per TEPPCO unit. Net proceeds of $257.0 million were used to reduce borrowings under the TEPPCO Revolving Credit Facility. Concurrently with this offering, TEPPCO sold 241,380 unregistered units at the public offering price of $29.00 per TEPPCO unit.

Texas Offshore Port System

In August 2008, we, together with Oiltanking Holding Americas, Inc. ("Oiltanking"), announced the formation of the Texas Offshore Port System, a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. Demand for such projects is being driven by planned and expected refinery expansions along the Gulf Coast, expected increases in shipping traffic and operating limitations of regional ship channels.

The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of crude oil storage capacity, and (iii) an 85-mile crude oil pipeline system having a transportation capacity of up to 1.8 million barrels per day, that will extend from the offshore port to a storage facility near Texas City, Texas. The joint venture's complementary project, referred to as the Port Arthur Crude Oil Express (or "PACE") will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. Development of the TOPS and PACE projects is supported by long-term contracts with affiliates of Motiva Enterprises LLC ("Motiva") and Exxon Mobil Corporation ("Exxon Mobil"), which have committed a combined 725 MBPD of crude oil to the projects. The timing of the construction and related capital costs of the TOPS and PACE projects will be affected by the acquisition of requisite permits.

We and Oiltanking own, through our respective subsidiaries, a two-thirds and one-third interest in the joint venture, respectively. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures currently expected to occur in 2010 and 2011. We have guaranteed up to approximately $1.4 billion, which includes a contingency amount for potential cost overruns, of the capital contribution obligations of our respective subsidiary partners in the joint venture. See Note 25 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for subsequent event information regarding our dissociation from TOPS in April 2009.

Acquisition of Remaining Interest in Dixie

In August 2008, we acquired the remaining 25.8% ownership interest in Dixie Pipeline Company ("Dixie") for $57.1 million. As a result of this transaction, we own 100% of Dixie, which owns a 1,371-mile pipeline system that delivers NGLs (primarily propane) to customers along the U.S. Gulf Coast and southeastern United States.

TEPPCO Revolving Credit Facility

In July 2008, commitments under the TEPPCO Revolving Credit Facility were increased from $700.0 million to $950.0 million. For additional information regarding this additional commitment of debt, see Note 14 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

Reorganization of Commercial Management Team

In July 2008, Mr. A. J. Teague, Executive Vice President, was elected as a Director to the Boards of both our general partner and that of Duncan Energy Partners and as Chief Commercial Officer responsible for managing all of the commercial activities of the two partnerships. In connection with Mr. Teague's appointment as Chief Commercial Officer, certain members of our senior management team were realigned to report to Mr. Teague. Mr. Teague will continue to report to Michael A. Creel, President and Chief Executive Officer ("CEO") of Enterprise Products Partners.

Jonah System Expansions

In June 2008, Jonah completed its Phase V expansion, which increased the combined gathering capacity of our Jonah and Pinedale fields systems from 1.5 Bcf per day to 2.35 Bcf per day. The increased capacity from the expansion has reduced system operating pressures and increased production rates and ultimate reserve recoveries.

Independence Trail and Hub Resume Operations

In April 2008, production at the Independence Hub natural gas platform was shut-in due to a leak in the flex-joint assembly where the Independence Trail export pipeline connects to the platform. In July 2008, repairs were completed and the Independence Hub platform and Trail pipeline returned to operation. Our Independence Trail export pipeline recorded $17.0 million of expense associated with the flex-joint repairs. We have submitted a claim with our insurance carriers regarding the flex-joint repair costs. To the extent that we receive cash proceeds from this claim in the future, such amounts would be recorded as income in the period of receipt.

EPO Issues $1.10 Billion of Senior Notes

In April 2008, EPO sold $400.0 million in principal amount of 5.65% fixed-rate, unsecured senior notes due April 2013 ("Senior Notes M") and $700.0 million in principal amount of 6.50% fixed-rate, unsecured senior notes due January 2019 ("Senior Notes N"). Net proceeds from this offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility. For additional information regarding this issuance of debt, see Note 14 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

TEPPCO Issues $1.00 Billion of Senior Notes

In March 2008, TEPPCO issued and sold in an underwritten public offering (i) $250.0 million principal amount of 5.90% Senior Notes due 2013, (ii) $350.0 million principal amount of 6.65% Senior Notes due 2018, and (iii) $400.0 million principal amount of 7.55% Senior Notes due 2038. The proceeds of this offering were used to repay borrowings outstanding under the TEPPCO Short-Term Credit Facility, which was terminated in March 2008. For additional information regarding this issuance of debt, see Note 14 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

Duncan Energy Partners' Shelf Registration Statement

In March 2008, Duncan Energy Partners filed a universal shelf registration statement with the SEC that authorized its issuance of up to $1.00 billion in debt and equity securities. As of February 2, 2009, Duncan Energy Partners has issued $0.5 million in equity securities under this registration statement.

Acquisition of Cenac and Horizon

In February 2008, we entered the marine transportation business for refined products, crude oil and condensate through the purchase of 42 tow boats, 89 tank barges and the economic benefit of certain related commercial agreements from Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr., the sole owner of Cenac Towing Co., Inc. and Cenac Offshore, L.L.C. (collectively, "Cenac"), for approximately $444.7 million in cash and newly issued TEPPCO units. Additionally, we assumed $63.2 million of Cenac's long-term debt. We financed the cash portion of the acquisition consideration and repaid the assumed debt with borrowings under the TEPPCO Short-Term Credit Facility.

In February 2008, we expanded our Petrochemical & Refined Products Services segment with the acquisition of marine assets from Horizon Maritime, L.L.C. ("Horizon"), a privately held Houston-based company and an affiliate of Mr. Cenac for $80.8 million in cash. We acquired 7 tow boats, 17 tank barges, rights to two tow boats under construction and certain related commercial and other agreements (or the associated economic benefits). In April 2008, we paid $3.0 million to Horizon pursuant to the purchase agreement upon delivery of one of the tow boats under construction, and in June 2008, we paid $3.8 million upon delivery of the second tow boat. We financed the acquisition with borrowings under the TEPPCO Short-Term Credit Facility.

Pioneer Cryogenic Natural Gas Processing Facility Commences Operations

In February 2008, we commenced operations of the Pioneer cryogenic natural gas processing facility. Located near the Opal Hub in southwestern Wyoming, this new facility is designed to process up to 700 MMcf/d of natural gas and extract as much as 30 MBPD of NGLs. We intend to maintain the operational capability of our Pioneer silica gel natural gas processing plant, which is located adjacent to the Pioneer cryogenic plant, as a back-up to provide producers with additional assurance of our processing capability at the complex. NGLs extracted at our Pioneer complex are transported on our Mid-America Pipeline System and ultimately to our Hobbs and Mont Belvieu NGL fractionators.

In late March 2008, operations at our Pioneer cryogenic natural gas processing facility were temporarily suspended following a release of natural gas and subsequent fire. No injuries resulted from the incident, which was restricted to a small area within the plant. The facility resumed operations in April 2008.

TEPPCO retires $355.0 Million of Senior Notes

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

Results of Operations

We have five reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Onshore Crude Oil Pipelines & Services, Offshore Pipelines & Services and Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before: (i) depreciation, amortization and accretion expense; (ii) non-cash impairment charges; (iii) operating lease expenses for which we do not have the payment obligation; (iv) gains and losses from asset sales and related transactions; and (v) general and administrative costs. Gross operating margin excludes other income and expense transactions, provision for income taxes, cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis and does not adjust for earnings attributable to noncontrolling interests. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions. Intercompany accounts and transactions are eliminated in the preparation of our consolidated financial statements.

We include equity in income of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners on a 100% basis. Volumetric data associated with the operations of Duncan Energy Partners are also included on a 100% basis in our consolidated statistical data.

For additional information regarding our business segments, see Note 16 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

Selected Price and Volumetric Data

The following table illustrates selected annual and quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods presented.

	Natural Gas, $/MMBtus (1)	NYMEX Crude Oil, $/barrel (2)	Ethane, $/gallon (1)	Propane, $/gallon (1)	Normal Butane, $/gallon (1)	Isobutane, $/gallon (1)	Natural Gasoline, $/gallon (1)	Polymer Grade Propylene, $/pound (1)	Refinery Grade Propylene, $/pound (1)
2006 Averages	$ 7.24	$ 66.23	$ 0.66	$ 1.01	$ 1.20	$ 1.24	$ 1.44	$ 0.47	$ 0.41
2007 Averages	$ 6.86	$ 72.24	$ 0.79	$ 1.21	$ 1.42	$ 1.49	$ 1.68	$ 0.52	$ 0.47
2008									
1st Quarter	$ 8.03	$ 97.82	$ 1.01	$ 1.47	$ 1.80	$ 1.87	$ 2.12	$ 0.61	$ 0.54
2nd Quarter	$ 10.94	$ 123.80	$ 1.05	$ 1.70	$ 2.05	$ 2.08	$ 2.64	$ 0.70	$ 0.67
3rd Quarter	$ 10.25	$ 118.22	$ 1.09	$ 1.68	$ 1.97	$ 1.99	$ 2.52	$ 0.78	$ 0.66
4th Quarter	$ 6.95	$ 58.08	$ 0.42	$ 0.80	$ 0.90	$ 0.96	$ 1.09	$ 0.37	$ 0.22
2008 Averages	$ 9.04	$ 99.73	$ 0.89	$ 1.41	$ 1.68	$ 1.72	$ 2.09	$ 0.62	$ 0.52

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including Oil Price Information Service (“OPIS”) and Chemical Market Associates, Inc. (“CMAI”). Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents a weighted-average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.
(2) Crude oil price is representative of an index price for West Texas Intermediate as measured on the New York Mercantile Exchange (“NYMEX”).

The following table presents our significant average throughput, production and processing volumetric data. These statistics are reported on a net basis, taking into account our ownership interests in certain joint ventures and reflect the periods in which we owned an interest in such operations. These statistics include volumes for newly constructed assets since the dates such assets were placed into service and for recently purchased assets since the date of acquisition.

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	2,021	1,877	1,769
NGL fractionation volumes (MBPD)	441	405	324
Equity NGL production (MBPD)	108	88	63
Fee-based natural gas processing (MMcf/d)	2,524	2,565	2,218
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	9,612	8,465	7,882
Onshore Crude Oil Pipelines & Services, net:			
Crude oil transportation volumes (MBPD)	696	652	678
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	1,408	1,641	1,520
Crude oil transportation volumes (MBPD)	169	163	153
Platform natural gas processing (MMcf/d)	632	494	159
Platform crude oil processing (MBPD)	15	24	15
Petrochemical & Refined Products Services, net:			
Butane isomerization volumes (MBPD)	86	90	81
Propylene fractionation volumes (MBPD)	58	68	56
Octane enhancement production volumes (MBPD)	9	9	9
Transportation volumes, primarily petrochemicals and refined products (MBPD)	818	882	806
Total, net:			
NGL, crude oil, refined products and petrochemical transportation volumes (MBPD)	3,704	3,574	3,406
Natural gas transportation volumes (BBtus/d)	11,020	10,106	9,402
Equivalent transportation volumes (MBPD) (1)	2,900	2,659	2,474

(1) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

Comparison of Results of Operations

The following table summarizes key components of our results of operations for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2008	2007	2006
Revenues	$ 35,469.6	$ 26,713.8	$ 23,612.1
Operating costs and expenses	33,618.9	25,402.1	22,420.3
General and administrative costs	137.2	127.2	95.9
Equity in income of unconsolidated affiliates	34.9	10.5	25.2
Operating income	1,748.4	1,195.0	1,121.1
Interest expense	540.7	413.0	324.2
Provision for income taxes	31.0	15.7	22.0
Net income	1,188.9	838.0	787.6
Net income attributable to noncontrolling interest	234.9	304.4	186.5
Net income attributable to Enterprise Products Partners L.P.	954.0	533.6	601.1

Effective January 1, 2009, we adopted new accounting guidance which established accounting and reporting standards for noncontrolling interests, which were previously identified as minority interest in our financial statements. The new guidance requires, among other things, that (i) noncontrolling interests be presented as a component of equity on our consolidated balance sheet (i.e., elimination of the “mezzanine” presentation previously used for minority interest); (ii) minority interest amounts be eliminated as a deduction in deriving net income or loss and, as a result, that net income or loss be allocated between controlling and noncontrolling interests; and (iii) comprehensive income or loss to be allocated between controlling and noncontrolling interest. Earnings per unit amounts are not affected by these changes. See

Note 15 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for additional information regarding noncontrolling interest.

The new presentation and disclosure requirements pertaining to noncontrolling interests have been applied retroactively to the supplemental consolidated financial information included in this Current Report on Form 8-K. As a result, net income reported for the years ended December 31, 2008, 2007 and 2006 in these supplemental financial statements is higher than that disclosed previously; however, the allocation of such net income results in our unitholders, general partner and noncontrolling interests (i.e., the former minority interest) receiving the same amounts as they did previously.

Our gross operating margin by segment and in total is as follows for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2008	2007	2006
Gross operating margin by segment:			
NGL Pipelines & Services	$ 1,325.0	$ 848.0	$ 785.7
Onshore Natural Gas Pipelines & Services	589.9	493.2	478.9
Onshore Crude Oil Pipelines & Services	132.2	109.6	97.8
Offshore Pipeline & Services	187.0	171.6	103.4
Petrochemical & Refined Products Services	374.9	342.0	305.1
Total segment gross operating margin	$ 2,609.0	$ 1,964.4	$ 1,770.9

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes and the cumulative effect of change in accounting principles, see “Other Items – Non-GAAP Reconciliations” included within this Item 7.

The following table summarizes the contribution to revenues from each business segment (including the effects of eliminations and adjustments) during the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services:			
Sales of NGLs	$ 14,573.5	$ 11,701.3	$ 9,429.2
Sales of other petroleum and related products	2.4	3.0	2.4
Midstream services	737.9	746.4	764.4
Total	15,313.8	12,450.7	10,196.0
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	3,089.4	1,481.6	1,103.1
Midstream services	727.0	844.3	802.8
Total	3,816.4	2,325.9	1,905.9
Onshore Crude Oil Pipelines & Services:			
Sales of crude oil	12,696.2	9,048.5	9,002.7
Midstream services	67.6	55.3	48.2
Total	12,763.8	9,103.8	9,050.9
Offshore Pipelines & Services:			
Sales of natural gas	2.8	3.2	2.1
Sales of other petroleum and related products	11.1	12.1	4.5
Midstream services	254.5	208.5	139.2
Total	268.4	223.8	145.8
Petrochemical & Refined Products Services:			
Sales of other petroleum and related products	2,757.6	2,207.2	1,938.9
Midstream services	549.6	402.4	374.6
Total	3,307.2	2,609.6	2,313.5
Total consolidated revenues	$ 35,469.6	$ 26,713.8	$ 23,612.1

Our revenues are derived from a wide customer base. During 2008, 2007 and 2006, our largest customer was Valero Energy Corporation and its affiliates, which accounted for 11.2%, 8.9% and 9.3%, respectively, of our revenues.

On January 6, 2009, LyondellBasell Industries ("LBI") announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. LBI accounted for 5.9% of our consolidated revenues during 2008. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. In addition, we are seeking to have LBI accept certain contracts and have filed claims pursuant to current Bankruptcy Court Orders that we expect will allow us to recover the majority of the remaining credit exposure.

Comparison of 2008 with 2007

Revenues for 2008 were $35.47 billion compared to $26.71 billion for 2007. The $8.76 billion year-to-year increase in consolidated revenues is primarily due to higher energy commodity sales volumes and prices during 2008 relative to 2007. These factors accounted for $8.61 billion of the year-to-year increase in consolidated revenues associated with our NGL, natural gas, crude oil and petrochemical marketing activities. Equity NGLs we produced at our newly constructed Meeker and Pioneer natural gas plants and sold in connection with our NGL marketing activities contributed $731.3 million of the year-to-year increase in marketing activity revenues. Collectively, the remainder of our consolidated revenues increased $143.4 million year-to-year primarily due to newly constructed assets we placed into service and recently acquired businesses, principally our Independence project and the marine transportation businesses.

Operating costs and expenses were $33.62 billion for 2008 versus $25.40 billion for 2007, an $8.22 billion year-to-year increase. The cost of sales of our marketing activities increased $7.10 billion year-to-year primarily due to higher energy commodity sales volumes and prices. Likewise, the operating costs and expenses of our natural gas processing plants increased $300.4 million year-to-year primarily due to higher energy commodity prices. Collectively, the remainder of our consolidated operating costs and expenses increased $815.4 million year-to-year primarily due to assets we constructed and placed into service or acquired since January 1, 2007. General and administrative costs increased $10.0 million year-to-year largely due to our acquisition of marine transportation businesses during 2008.

Changes in our revenues and costs and expenses year-to-year are primarily explained by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.40 per gallon during 2008 versus $1.19 per gallon during 2007. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $9.04 per MMBtus during 2008 versus $6.86 per MMBtus during 2007. The market price of crude oil (as measured on the NYMEX) averaged $99.73 per barrel during 2008 compared to $72.24 per barrel during 2007. See "Selected Price and Volumetric Data" included within this Item 7 for additional historical energy commodity pricing information.

Equity in income of our unconsolidated affiliates was $34.9 million for 2008 compared to $10.5 million for 2007, a $24.4 million year-to-year increase. Equity in income of our investment in Cameron Highway Oil Pipeline Company ("Cameron Highway") increased $27.6 million year-to-year due to higher transportation volumes and lower interest expense. Equity in income of our investment in Seaway Crude Pipeline Company ("Seaway") increased $9.1 million year-to-year due to higher transportation fees. A non-cash impairment charge of $7.0 million associated with our investment in Nemo Gathering Company, LLC ("Nemo") reduced equity in income for 2007. Collectively, equity in income of our other investments decreased $19.3 million year-to-year primarily due to higher repair and maintenance expenses during 2008 relative to 2007 as well as the effects of downtime and reduced volumes attributable to Hurricanes Gustav and Ike.

Operating income for 2008 was $1.75 billion compared to $1.20 billion for 2007. Collectively, the aforementioned changes in revenues, costs and expenses and equity in income of unconsolidated affiliates contributed to the $553.4 million year-to-year increase in operating income.

Interest expense increased to $540.7 million for 2008 from $413.0 million for 2007. The $127.7 million year-to-year increase in interest expense is primarily due to our issuance of senior and junior notes during 2008 and 2007 to fund our capital growth projects and business combinations. Our average debt principal outstanding during 2008 was $10.17 billion compared to $7.82 billion during 2007. Other income for 2007 includes a $59.6 million gain on the sale of our interests in Mont Belvieu Storage Partners, L.P. and its general partner (collectively, "MB Storage"). See Note 11 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for additional information regarding our sale of these equity method investments.

Provision for income taxes increased $15.3 million year-to-year primarily due to higher expenses associated with the Texas Margin Tax. The increase in expenses for the Texas Margin Tax primarily reflects a higher taxable margin in the State of Texas during 2008 relative to 2007. In addition, we recognized a $5.1 million benefit with respect to the Texas Margin Tax during 2007 due to the reorganization of certain of our entities from partnerships to limited liability companies.

As a result of items noted in the previous paragraphs, our consolidated net income increased $350.9 million year-to-year to $1.19 billion for 2008 compared to $838.0 million for 2007. Net income attributable to noncontrolling interests was $234.9 million for 2008 compared to $304.4 million for 2007. Such amounts reflect $193.6 million and $273.8 million of net income for 2008 and 2007, respectively, attributable to TEPPCO Partners, L.P. Net income attributable to Enterprise Products Partners increased $420.4 million year-to-year to $954.0 million for 2008 compared to $533.6 million for 2007.

In general, Hurricanes Gustav and Ike had an adverse effect across our operations in the Gulf of Mexico and along the U.S. Gulf Coast during 2008. Storm-related disruptions in natural gas, NGL and crude oil production in these regions resulted in reduced volumes available to our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which in turn caused a decrease in gross operating margin for certain operations. In addition, property damage caused by Hurricanes Gustav and Ike resulted in lower revenues due to facility downtime as well as higher operating costs and expenses at certain of our plants and pipelines. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, gross operating margin for 2008 includes $49.1 million of repair expenses for property damage sustained by our assets as a result of the hurricanes.

We estimate that gross operating margin was reduced by approximately $81.0 million during 2008 due to the effects of Hurricanes Gustav and Ike as a result of supply interruptions and facility downtime. For more information regarding our insurance program and claims related to these storms, see Note 21 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $1.33 billion for 2008 compared to $848.0 million for 2007. The $477.0 million year-to-year increase in segment gross operating margin is due to strong natural gas processing margins and petrochemical demand for NGLs as well as an increase in equity NGL production attributable to our Meeker and Pioneer natural gas processing facilities. Results for 2007 include $32.7 million of proceeds from business interruption insurance claims compared to $1.1 million of proceeds for 2008. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $815.3 million for 2008 compared to $389.1 million for 2007. Equity NGL production increased to 108 MBPD during 2008 from 88 MBPD during 2007. The $426.2 million year-to-year increase in gross operating margin is largely due to contributions from our Meeker and Pioneer cryogenic natural gas processing facilities, which commenced commercial operations during October 2007 and February 2008, respectively. These facilities contributed $274.5 million of the year-to-year increase in gross operating margin and produced 49 MBPD of equity NGLs during 2008 compared to 23 MBPD during 2007. Collectively, gross operating margin from the remainder of this business increased $151.7 million year-to-year primarily due improved results from our NGL marketing activities attributable to higher NGL sales margins and volumes in 2008 relative to 2007. Results for 2008 include $6.8 million of hurricane-related property damage repair expenses associated with our natural gas processing plants in southern Louisiana.

Gross operating margin from our NGL pipelines and related storage business was $397.4 million for 2008 compared to $331.1 million for 2007, a $66.3 million year-to-year increase. Total NGL transportation volumes increased to 2,021 MBPD during 2008 from 1,877 MBPD during 2007. Gross operating margin from our Mid-America and Seminole Pipeline Systems increased $43.6 million year-to-year due to higher transportation volumes and an increase in the system-wide tariff. These pipeline systems contributed 116 MBPD of the year-to-year increase in NGL transportation volumes. Gross operating margin from our Mont Belvieu storage complex increased $15.5 million as a result of higher storage revenues during 2008 relative to 2007. Collectively, gross operating margin from the remainder of our NGL pipelines and storage business increased $7.2 million year-to-year attributable to higher transportation volumes on our Dixie and Lou-Tex NGL Pipeline Systems and lower maintenance and pipeline integrity expenses on our Dixie and South Louisiana Pipeline Systems. In general the improved results from our NGL pipeline and storage assets were partially offset by downtime and reduced volumes as a result of Hurricanes Gustav and Ike during 2008. Results for 2008 include $0.9 million of hurricane-related property damage repair expenses.

Gross operating margin from our NGL fractionation business was $111.2 million for 2008 compared to $95.1 million for 2007. Fractionation volumes increased from 405 MBPD during 2007 to 441 MBPD during 2008. Gross operating margin from our Hobbs fractionator increased $26.7 million year-to-year. Our Hobbs fractionator was placed into service during August 2007 and contributed a 41 MBPD year-to-year increase in NGL fractionation volumes. Collectively, gross operating margin from our other NGL fractionators decreased $10.6 million year-to-year primarily due to downtime and lower volumes at our Norco, South Texas and Baton Rouge fractionators and a combined $0.9 million of hurricane-related property damage repair expenses in 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $589.9 million for 2008 compared to $493.2 million for 2007, a $96.7 million year-to-year increase. Our onshore natural gas transportation volumes were 9,612 BBtus/d during 2008 compared to 8,465 BBtus/d during 2007. Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business increased to $550.5 million for 2008 from $464.8 million for 2007. The $85.7 million year-to-year increase in gross operating margin is primarily due to (i) higher revenues from our San Juan Gathering System, (ii) higher transportation activity on our Texas Intrastate System, (iii) higher natural gas sales margins on our Acadian Gas System and (iv) an increase in gathering volumes on our Jonah System as a result of system expansion projects. Results for 2008 include $1.3 million of hurricane-related property damage repair expenses attributable to Hurricanes Gustav and Ike.

Gross operating margin from our natural gas storage business was $39.4 million for 2008 compared to $28.4 million for 2007. The $11.0 million year-to-year increase in gross operating margin is primarily due to increased storage activity at our Petal natural gas storage facility and improved results at our Wilson facility. We placed additional natural gas storage caverns in operation during the third quarters of 2007 and 2008 at our Petal facility, which provided an additional 1.6 Bcf and 4.2 Bcf of subscribed capacity, respectively.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $132.2 million for 2008 compared to $109.6 million for 2007. Total onshore crude oil transportation volumes were 696 MBPD during 2008 compared to 652 MBPD during 2007. The $22.6 million year-to-year increase in segment gross operating margin is primarily due to an increase in crude oil transportation volumes and fees during 2008 relative to 2007. Completion of system expansions in south and west Texas contributed 42 MBPD of the year-to-year increase in crude oil transportation volumes. Average transportation fees on the pipeline system owned by Seaway were higher during 2008 compared to 2007 as a result of an increase in volumes transported on a spot basis and higher long-haul volumes, both of which are subject to a higher tariffs.

Offshore Pipelines & Services. Gross operating margin from this business segment was $187.0 million for 2008 compared to $171.6 million for 2007. The $15.4 million year-to-year increase in segment gross operating margin is primarily due to contributions from our Independence Hub platform and Trail pipeline and improved results from our Cameron Highway Oil Pipeline. Results from this business segment for 2008 were negatively impacted by (i) downtime and $17.0 million of repair expenses associated with a leak on the Independence Trail pipeline and (ii) the effects of Hurricanes Gustav and Ike including downtime, reduced volumes and $37.2 million of property damage repair expenses. Results for 2008 include $0.2 million of proceeds from business interruption insurance claims compared to $3.4 million of proceeds during 2007. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance.

Gross operating margin from our offshore platform services business was $144.8 million for 2008 compared to $111.7 million for 2007, a $33.1 million year-to-year increase. Our Independence Hub platform, which was completed in March 2007, provided a $49.5 million year-to-year increase in gross operating margin. Gross operating margin increased year-to-year despite the platform being shut-in for 66 days during the second quarter of 2008 due to a leak on the Independence Trail export pipeline. While the Independence Hub platform did not earn volumetric fees during the period of suspended operations, the platform continued to earn its fixed demand revenues of approximately $4.6 million per month. Gross operating margin from the remainder of this business decreased $16.4 million year-to-year primarily due to the effects of Hurricanes Gustav and Ike and upstream supply disruptions. Results for our offshore platform services business include $5.0 million of hurricane-related property damage repair expenses in 2008. Our net platform natural gas processing volumes increased to 632 MMcf/d during 2008 compared to 494 MMcf/d during 2007.

Gross operating margin from our offshore crude oil pipeline business was $35.1 million for 2008 versus $21.1 million for 2007, a $14.0 million year-to-year increase. Gross operating margin increased $27.6 million year-to-year due to increased equity in income of Cameron Highway, which benefited from higher crude oil transportation volumes and lower interest expense in 2008 relative to 2007. Net to our ownership interest, crude oil transportation volumes on the Cameron Highway Oil Pipeline System were 80 MBPD in 2008 compared to 44 MBPD in 2007. Gross operating margin from the remainder of this business decreased $13.6 million year-to-year due to the effects of Hurricanes Gustav and Ike, which include (i) downtime resulting from damage sustained by our pipelines as well as downstream assets owned by third-parties and (ii) reduced volumes available to our pipelines as a result of upstream supply disruptions. Results for our offshore crude oil pipeline business include $2.3 million of hurricane-related property damage repair expenses in 2008. Total offshore crude oil transportation volumes were 169 MBPD during 2008 versus 163 MBPD during 2007.

Gross operating margin from our offshore natural gas pipeline business was $6.9 million for 2008 compared to $35.4 million for 2007. Offshore natural gas transportation volumes were 1,408 BBtus/d during 2008 versus 1,641 BBtus/d during 2007. Gross operating margin from our Independence Trail pipeline, which first received production in July 2007, increased $28.4 million year-to-year on a 241 BBtus/d increase in transportation volumes. Collectively, gross operating margin from our other offshore natural gas pipelines decreased $56.9 million year-to-year primarily due to the effects of Hurricanes Gustav and Ike. Results for 2008 include $29.9 million of hurricane-related property damage repair expenses.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $374.9 million for 2008 compared to $342.0 million for 2007.

Gross operating margin from propylene fractionation and related activities was $87.2 million for 2008 compared to $66.3 million for 2007. The $20.9 million year-to-year increase in gross operating margin is largely due to higher propylene sales margins during 2008 relative to 2007. Results for our propylene fractionation and related pipeline business for 2008 include $0.8 million of hurricane-related property damage repair expenses.

Gross operating margin from butane isomerization was $95.9 million for 2008 compared to $91.4 million for 2007. The $4.5 million year-to-year increase in gross operating margin is primarily due to strong demand for high-purity isobutane and increased by-product sales revenues as a result of higher NGL prices during 2008 relative to 2007. Butane isomerization volumes decreased to 86 MBPD during 2008 compared to 90 MBPD during 2007 due to production interruptions resulting from Hurricane Ike and operational issues at our octane enhancement facility during the third quarter of 2008. Gross operating margin from octane enhancement was a loss of $11.3 million for 2008 compared to $18.3 million of earnings for 2007. The $29.6 million year-to-year decrease in gross operating margin is primarily due to downtime, reduced volumes and higher operating expenses as a result of operational issues during the third quarter of 2008 and the effects of Hurricane Ike.

Gross operating margin from refined products pipelines and related activities was $132.9 million for 2008 compared to $162.7 million for 2007. The $29.8 million year-to-year decrease in gross operating margin is primarily due to higher expenses on our Products Pipeline System during 2008 relative to 2007 for storage tank and pipeline maintenance and the effects of lower transportation volumes during 2008. Transportation volumes on our refined products pipelines decreased to 702 MBPD during 2008 from 768 MBPD during 2007 due in part to the effects of Hurricanes Gustav and Ike. Results for 2008 include $0.9 million of hurricane-related property damage repair expenses.

Gross operating margin from marine transportation and other services was $70.2 million for 2008 compared to $3.3 million for 2007. The $66.9 million year-to-year increase in gross operating margin is primarily attributable to the marine transportation businesses we acquired during 2008 from Cenac and Horizon. At December 31, 2008, our fleet of marine vessels consisted of 51 tow boats and 113 barges. The utilization of our marine services fleet averaged 93% during 2008.

Comparison of 2007 with 2006

Revenues for 2007 were $26.71 billion compared to $23.61 billion for 2006. The $3.10 billion year-to-year increase in consolidated revenues is primarily due to higher sales volumes and energy commodity prices in 2007 relative to 2006. These factors accounted for a $2.99 billion increase in consolidated revenues associated with our NGL, natural gas, crude oil and petrochemical marketing activities. Revenues from business interruption insurance proceeds totaled $36.1 million in 2007 compared to $63.9 million in 2006. Collectively, the remainder of our consolidated revenues increased $139.5 million year-to-year primarily due to contributions from our Independence Hub platform and Trail pipeline, which we placed into service during 2007.

Operating costs and expenses were $25.40 billion for 2007 compared to $22.42 billion for 2006, a $2.98 billion year-to-year increase. The cost of sales of our NGL, natural gas, crude oil and petrochemical products increased $2.43 billion year-to-year as a result of an increase in volumes and higher energy commodity prices. Operating costs and expenses associated with our natural gas processing plants increased $266.3 million year-to-year as a result of higher energy commodity prices in 2007 relative to 2006. Collectively, the remainder of our consolidated operating costs and expenses increased $283.7 million year-to-year primarily due to assets we constructed and placed into service or acquired since January 1, 2006, including expansions of our Jonah System. General and administrative costs increased $31.3 million year-to-year laregely due to the recognition of a severance obligation during 2007 and an increase in legal fees.

Changes in our revenues and costs and expenses year-to-year are primarily explained by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.19 per gallon during 2007 versus $1.00 per gallon during 2006. The Henry Hub market price of natural gas averaged $6.86 per MMBtus during 2007 versus $7.24 per MMBtus during 2006. The NYMEX price for crude oil averaged $72.24 per barrel during 2007 compared to an average of $66.23 per barrel during 2006.

Equity in income of our unconsolidated affiliates was $10.5 million for 2007 compared to $25.2 million for 2006, a $14.7 million year-to-year decrease. A non-cash impairment charge of $7.0 million associated with our investment in Nemo reduced equity in income for 2007. Equity in income for 2006 includes a non-cash impairment charge of $7.4 million related to our investment in Neptune Pipeline Company, L.L.C. (“Neptune”). Collectively, equity in income of our other unconsolidated affiliates decreased $15.1 million year-to-year primarily due to reduced equity in income of our investments in Seaway and MB Storage. We sold our equity method investments in MB Storage during 2007.

Operating income for 2007 was $1.20 billion compared to $1.12 billion for 2006. Collectively, the aforementioned changes in revenues, costs and expenses and equity in income from unconsolidated affiliates contributed to the $73.9 million year-to-year increase in operating income.

Interest expense increased to $413.0 million for 2007 from $324.2 million for 2006. The $88.8 million year-to-year increase in interest expense is primarily due to our issuance of senior and junior notes during 2007 and junior notes during 2006. Our consolidated interest expense for 2007 includes $11.6 million associated with Duncan Energy Partners’ credit facility. Our average debt principal outstanding was $7.82 billion during 2007 compared to $6.45 billion during 2006. Other income for 2007 includes a $59.6 million gain on the sale of our interests in MB Storage. Provision for income taxes decreased $6.3 million year-to-year primarily due to a $5.1 million benefit we recorded during 2007 with respect to the Texas Margin Tax.

As a result of items noted in the previous paragraphs, our consolidated net income increased $50.3 million year-to-year to $838.0 million for 2007 compared to $787.6 million for 2006. Net income for 2006 includes a $1.5 million benefit relating to the cumulative effect of change in accounting principle. For additional information regarding the cumulative effect of change in accounting principle we recorded in 2006, see Note 8 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K. Net income attributable to noncontrolling interests was $304.4 million for 2007 compared to $186.5 million for 2006. Such amounts reflect $273.8 million and $177.4 million of net income for 2007 and 2006, respectively, attributable to TEPPCO Partners, L.P. Net income attributable to Enterprise Products Partners decreased $67.5 million year-to-year to $533.6 million for 2007 compared to $601.1 million for 2006.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $848.0 million for 2007 compared to $785.7 million for 2006. Gross operating margin for 2007 includes $32.7 million of proceeds from business interruption insurance claims compared to $40.4 million of proceeds during 2006. Strong demand for NGLs in 2007 compared to 2006 led to higher natural gas processing margins, increased volumes of natural gas processed under fee-based contracts and higher NGL throughput volumes at certain of our pipelines and fractionation facilities. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from NGL pipelines and related storage business was $331.1 million for 2007 compared to $291.0 million for 2006. Total NGL transportation volumes increased to 1,877 MBPD during 2007 from 1,769 MBPD during 2006. The $40.1 million year-to-year increase in gross operating margin is primarily due to higher pipeline transportation and NGL storage volumes at certain of our facilities and higher transportation fees charged to shippers on our Mid-America Pipeline System. Our DEP South Texas NGL Pipeline, which we completed and placed into service during 2007, generated $21.1 million of gross operating margin and 73 MBPD of NGL transportation volumes during the year.

Gross operating margin from our natural gas processing and related NGL marketing business was $389.1 million for 2007 compared to $361.2 million for 2006. The $27.9 million year-to-year increase in gross operating margin is largely due to improved results from our South Texas, Louisiana and Chaco natural gas processing facilities attributable to higher volumes and equity NGL sales revenues, all of which were partially offset by expenses associated with start-up delays at our Meeker and Pioneer natural gas processing plants. Fee-based processing volumes increased to 2.6 Bcf/d during 2007 from 2.2 Bcf/d during 2006. Equity NGL production increased to 88 MBPD during 2007 from 63 MBPD during 2006.

Gross operating margin from NGL fractionation was $95.1 million for 2007 compared to $93.1 million for 2006. Fractionation volumes increased from 324 MBPD during 2006 to 405 MBPD during 2007. The year-to-year increase in gross operating margin of $2.0 million is primarily due to higher volumes at our Norco NGL fractionator during 2007 relative to 2006. Our Norco NGL fractionator returned to normal operating rates in the second quarter of 2006 after suffering a reduction of fractionation volumes due to the effects of Hurricane Katrina. Revenues generated by our Hobbs NGL fractionator, which became operational in August 2007, were largely offset by start-up expenses. Fractionation volumes for 2007 include 36 MBPD from our Hobbs fractionator.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $493.2 million for 2007 compared to $478.9 million for 2006. Our total onshore natural gas transportation volumes were 8,465 BBtus/d for 2007 compared to 7,882 BBtus/d for 2006. Gross operating margin from our onshore natural gas pipeline business was $464.8 million for 2007 compared to $457.8 million for 2006, a $7.0 million year-to-year increase. Gross operating margin from our Jonah System increased $32.0 million year-to-year due to higher natural gas gathering volumes during 2007 as a result of system expansion projects. Results from our onshore natural gas pipeline business for 2007 include $5.5 million of gross operating margin from our Piceance Creek Gathering System, which we acquired in December 2006. Collectively, gross operating margin from the remainder of this business decreased $30.5 million year-to-year largely due to higher operating costs on our Acadian Gas System, Carlsbad Gathering System, Texas Intrastate System and Val Verde Gathering System.

Gross operating margin from our natural gas storage business was $28.4 million for 2007 compared to $21.1 million for 2006. The $7.3 million year-to-year increase in gross operating margin is largely due to lower repair costs at our Wilson natural gas storage facility in 2007 relative to 2006. Also, results for 2006 include a loss on the sale of cushion gas at our Wilson facility. Our Wilson natural gas storage facility remained out of operation through 2007 due to ongoing repairs. Gross operating margin from our Petal facility includes an $8.4 million benefit in 2006 for a well measurement gain.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $109.6 million for 2007 compared to $97.8 million for 2006. Gross operating margin decreased $8.9 million year-to-year due to reduced equity in income from our investment in Seaway. Our share of Seaway's earnings varies over time in accordance with its partnership agreement. Our sharing ratio (which applies to Seaway's earnings and cash distributions) decreased from 60% to 40% during 2006. In addition, our equity in income from Seaway was negatively affected by a 40 MBPD year-to-year decrease in crude oil transportation volumes, net to our ownership interest.

Collectively, gross operating margin from the remainder of the businesses classified within this segment increased $20.7 million year-to-year. Our crude oil pipelines benefited from higher tariffs and transportation volumes during 2007 relative to 2006. Improved results from our crude oil marketing activities are attributable to higher crude oil sales margins and volumes during 2007 relative to 2006. Total onshore crude oil transportation volumes were 652 MBPD during 2007 compared to 678 MBPD during 2006.

Offshore Pipelines & Services. Gross operating margin from this business segment was $171.6 million for 2007 compared to $103.4 million for 2006, a year-to-year increase of $68.2 million. Our Independence project contributed $85.0 million of gross operating margin during 2007 on average natural gas throughput of 423 BBtus/d. Segment gross operating margin for 2007 includes $3.4 million of proceeds from business interruption insurance claims compared to $23.5 million of proceeds in 2006. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our offshore platform services business was $111.7 million for 2007 compared to $34.6 million for 2006. The $77.1 million year-to-year increase in gross operating margin is primarily due to our start up of the Independence Hub Platform in 2007, which contributed $63.6 million of gross operating margin in 2007. In addition, gross operating margin from the remainder of this business increased $13.5 million year-to-year primarily due to higher volumes during 2007 versus 2006. Our net platform natural gas processing volumes increased to 494 MMcf/d in 2007 from 159 MMcf/d in 2006.

Gross operating margin from our offshore natural gas pipeline business was $35.4 million for 2007 compared to $22.4 million for 2006. Offshore natural gas transportation volumes were 1,641 BBtus/d during 2007 versus 1,520 BBtus/d during 2006. Our Independence Trail Pipeline reported $21.4 million of gross operating margin and 423 BBtus/d of transportation volumes for 2007. Results from our Independence Trail Pipeline were partially offset by a decrease in volumes and revenues from our Viosca Knoll Gathering System and Constitution Gas Pipeline. Gross operating margin for 2007 includes a non-cash impairment charge of $7.0 million associated with our investment in Nemo compared to a non-cash charge of $7.4 million in 2006 related to our investment in Neptune.

Gross operating margin from our offshore crude oil pipeline business was $21.1 million for 2007 versus $23.0 million for 2006. The $1.9 million year-to-year decrease in gross operating margin is primarily due to lower transportation volumes on certain of our offshore crude oil pipelines and higher operating costs on our Poseidon Oil Pipeline System during 2007 relative to 2006. An increase in revenues year-to-year on our Cameron Highway Oil Pipeline System attributable to higher volumes was more than offset by a one-time expense of $8.8 million associated with the early termination of Cameron Highway's credit facility. Crude oil transportation volumes on our Cameron Highway Oil Pipeline System, net to our ownership interest, were 44 MBPD during 2007 compared to 32 MBPD during 2006. Total offshore crude oil transportation volumes were 163 MBPD during 2007 versus 153 MBPD during 2006.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $342.0 million for 2007 compared to $305.1 million for 2006.

Gross operating margin from propylene fractionation and related activities was $66.3 million for 2007 versus $67.2 million for 2006. The $0.9 million year-to-year decrease in gross operating margin is primarily attributable to higher operating costs and expenses from our propylene pipelines and our propylene storage and export facility.

Gross operating margin from butane isomerization was $91.4 million for 2007 compared to $73.2 million for 2006. The $18.2 million year-to-year increase in gross operating margin is attributable to higher processing volumes and by-products sales revenues. Butane isomerization volumes were 90 MBPD for 2007 compared to 81 MBPD for 2006. Gross operating margin from octane enhancement was $18.3 million for 2007 compared to $36.6 million for 2006. The year-to-year decrease of $18.3 million is primarily due to lower sales margins in 2007 relative to 2006.

Gross operating margin from refined products pipelines and related activities was $162.7 million for 2007 compared to $124.5 million for 2006. The $38.2 million year-to-year increase in gross operating margin is primarily due to higher transportation volumes and fees during 2007 relative to 2006. Transportation volumes on our refined products pipelines were 768 MBPD during 2007 compared to 701 MBPD during 2006. Refined products transportation volumes increased year-to-year primarily due to higher demand in Midwest markets for motor fuel and distillates. Certain of our refined products transportation tariffs increased during February and July 2007 contributing to the year-to-year increase in gross operating margin. In addition, the average fee earned by our Products Pipeline System for the transportation of propane and butanes was higher during 2007 relative to 2006, which reflects an increase in long-haul deliveries at a higher fee during 2007.

Gross operating margin from other services, principally the distribution of lubrication oils and specialty chemicals was $3.3 million for 2007 compared to $3.5 million for 2006.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and revolving credit arrangements. Capital expenditures for long-term needs resulting from business expansion projects and acquisitions are expected to be funded by a variety of sources (either separately or in combination) including operating cash flows, borrowings under credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interests in assets to affiliates or third parties. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At December 31, 2008, we had $61.7 million of unrestricted cash on hand and approximately $1.73 billion of available credit under EPO's Multi-Year Revolving Credit Facility, the TEPPCO Revolving Credit Facility and a new credit facility executed in November 2008. We had approximately $11.56 billion in principal outstanding under consolidated debt agreements at December 31, 2008. In total, our consolidated liquidity at December 31, 2008 was approximately $1.92 billion, which includes the available borrowing capacity of our consolidated subsidiaries such as Duncan Energy Partners.

Registration Statements

Universal Shelf Registration Statements. We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its liquidity and capital spending requirements. We have a universal shelf registration statement on file with the SEC that allows us to issue an unlimited amount of debt and equity securities for general partnership purposes. In April 2008, EPO issued $1.10 billion in principal amount of fixed-rate, unsecured senior notes under this registration statement.

In December 2008, EPO also issued $500.0 million in principal amount of fixed-rate, unsecured senior notes. Net proceeds from these senior note offerings were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

In January 2009, we sold 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit under this registration statement. We used the net proceeds of $225.6 million from this offering to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility, which may be reborrowed to fund capital expenditures and other growth projects, and for general partnership purposes.

In March 2008, Duncan Energy Partners filed a universal shelf registration statement with the SEC that authorized its issuance of up to $1 billion in debt and equity securities. In December 2008, Duncan Energy Partners issued $0.5 million in equity securities under its registration statement.

Distribution Reinvestment Plan. During 2003, we instituted a distribution reinvestment plan ("DRIP"). We have a registration statement on file with the SEC authorizing the issuance of up to 25,000,000 common units in connection with the DRIP. The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units of our partnership. During the year ended December 31, 2008, we issued 5,368,310 common units in connection with our DRIP, which generated proceeds of $134.7 million from plan participants. In November 2008, affiliates of EPCO reinvested $67.0 million in connection with the DRIP.

Employee Unit Purchase Plan. In addition, we have a registration statement on file related to our employee unit purchase plan, under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. During the year ended December 31, 2008, we issued 155,636 common units to employees under this plan, which generated proceeds of $4.5 million.

For information regarding our public debt obligations or partnership equity, see Notes 14 and 15, respectively, of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

Letter of Credit Facility

In October 2008, EPO entered into a $100.0 million letter of credit facility. EPO issued a $70.0 million letter of credit under this new facility, which remained outstanding at December 31, 2008. This letter of credit facility does not reduce the amount available under EPO's Multi-Year Revolving Credit Facility.

Credit Ratings

At March 2, 2009, the investment-grade credit ratings of EPO's and TEPPCO's senior unsecured debt securities remain unchanged from 2008 at Baa3 by Moody's Investor Services; BBB- by Fitch Ratings; and BBB- by Standard and Poor's. Such ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any security. 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.

Based on the characteristics of the $1.55 billion of fixed/floating unsecured junior subordinated notes that EPO issued in 2006 and 2007 and TEPPCO issued in 2007, the rating agencies assigned partial equity treatment to the notes. Moody's Investor Services and Standard and Poor's each assigned 50% equity treatment and Fitch Ratings assigned 75% equity treatment.

In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, EPO entered into a $54.0 million, ten-year, fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). The indenture agreement for this loan contains an acceleration clause whereby if EPO's credit rating by Moody's Investor Services declines below Baa3 in combination with our credit rating at Standard & Poor's declining below BBB-, the $54.0 million principal balance of this loan, together with all accrued and unpaid interest would become immediately due and payable 120 days following such event. If such an event occurred, EPO would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support its obligation under this loan.

A downgrade of our credit ratings could result in our being required to post financial collateral up to the amount of our guaranty of indebtedness of our Centennial joint venture, which was $65.0 million at December 31, 2008. Further, from time to time we enter into contracts in connection with our commodity and interest rate hedging activities that require the posting of financial collateral, which may be substantial, if our credit were to be downgraded below investment grade.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (dollars in millions). For information regarding the individual components of our cash flow amounts, see the Supplemental Statements of Consolidated Cash Flows included under Exhibit 99.2 of this Current Report on Form 8-K .

	For the Year Ended December 31,		
	2008	2007	2006
Net cash flows provided by operating activities	$ 1,567.1	$ 1,953.6	$ 1,459.1
Cash used in investing activities	3,246.9	2,871.8	1,973.6
Cash provided by financing activities	1,690.7	946.3	495.3

Net cash flows provided by operating activities are largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; feedstock in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows. For a more complete discussion of these and other risk factors pertinent to our business, see "Risk Factors" under Item 1A within this Exhibit 99.1.

Our Supplemental Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) other non-cash amounts such as depreciation, amortization, operating lease expense paid by EPCO, changes in the fair market value of derivative instruments and equity in earnings from unconsolidated affiliates (net cash flows provided by operating activities reflect the actual cash distributions we receive from such investees), and (iv) the effects of all items classified as investing or financing cash flows, such as proceeds from asset sales and related transactions or extinguishment of debt.

In general, the net effect of changes in operating accounts results from the timing of cash receipts from sales and cash payments for purchases and other expenses during each period. Increases or decreases in inventory are influenced by the quantity of products held in connection with our marketing activities and changes in energy commodity prices.

Cash used in investing activities primarily represents expenditures for additions to property, plant and equipment, business combinations and investments in unconsolidated affiliates. Cash provided by financing activities generally consists of borrowings and repayments of debt, distributions to partners and proceeds from the issuance of equity securities. Amounts presented in our Supplemental Statements of Consolidated Cash Flows for borrowings and repayments under debt agreements are influenced by the magnitude of cash receipts and payments under our revolving credit facilities.

The following information highlights the significant year-to-year variances in our cash flow amounts:

Comparison of 2008 with 2007

Operating Activities. Net cash flows provided by operating activities were $1.57 billion for 2008 compared to $1.95 billion for 2007. The $386.5 million decrease in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding distributions received from unconsolidated affiliates and cash payments for interest) decreased $240.1 million year-to-year. Although our gross operating margin increased year-to-year (see "Results of Operations" within this Item 7), the reduction in operating cash flow is generally due to the timing of related cash receipts and disbursements. The $240.1 million total year-to-year decrease also reflects a $127.3 million decrease in cash proceeds we received from insurance claims related to certain named storms. For information regarding cash proceeds from business interruption and property damage claims, see Note 21 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

§ Cash distributions received from unconsolidated affiliates decreased $6.2 million year-to-year primarily due to the sale of TEPPCO's ownership interest in MB Storage in the first quarter of 2007. We received $10.4 million of distributions from MB Storage in 2007. The decrease in distributions received from unconsolidated affiliates related to MB Storage was partially offset by increased distributions from Cameron Highway.

§ Cash payments for interest increased $140.2 million year-to-year primarily due to increased borrowings to finance our capital spending program. Our average debt balance for 2008 was $10.17 billion compared to $7.82 billion for 2007.

Investing Activities. Cash used in investing activities was $3.25 billion for 2008 compared to $2.87 billion for 2007. The $375.1 million increase in cash used for investing activities was primarily due to the following:

§ Cash used for business combinations increased $517.5 million year-to-year, of which approximately $346.0 million was for business combinations related to our marine transportation businesses. In addition, during 2008 we acquired (i) 100% of the membership interest in Great Divide Gathering LLC for $125.2 million, (ii) the remaining interests in Dixie for $57.1 million and (iii) additional interests in Tri-States NGL Pipeline, L.L.C. ("Tri-States") for $18.7 million.

§ Proceeds from the sale of assets and related transactions decreased $146.9 million year-to-year primarily due to the sale of certain equity interests and related storage assets located in Mont Belvieu, Texas during 2007.

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, decreased $194.0 million year-to-year. For additional information related to our capital spending program, see "Capital Spending" included within this Item 7.

§ Cash outlays for investments in unconsolidated affiliates decreased by $172.1 million year-to-year. Expenditures for 2007 include the $216.5 million we contributed to Cameron Highway during the second quarter of 2007. Cameron Highway used these funds, along with an equal contribution from our 50% joint venture partner in Cameron Highway, to repay approximately $430.0 million of its outstanding debt. Expenditures for 2008 include (i) $22.5 million in contributions to White River Hub, LLC, (ii) $11.1 million in contributions to Centennial Pipeline LLC and (iii) $36.0 million to acquire a 49% interest in Skelly-Belvieu Pipeline Company, L.L.C.

- § An $85.5 million increase in restricted cash (a cash outflow) due to margin requirements related to our hedging activities. See Item 7A within this Exhibit 99.1 for information regarding our interest rate and commodity risk hedging portfolios.

Financing Activities. Cash provided by financing activities was $1.69 billion for 2008 compared to $946.3 million for 2007. The $744.4 million increase in cash provided by financing activities was primarily due to the following:

- § Net borrowings under our consolidated debt agreements increased $923.8 million year-to-year. In April 2008, EPO sold $400.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes M") and $700.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes N"). In November 2008, EPO executed a Japanese yen term loan agreement in the amount of 20.7 billion yen (approximately $217.6 million U.S. dollar equivalent). In December 2008, EPO sold $500.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes O"). We used the proceeds from these borrowings primarily to repay amounts borrowed under our Multi-Year Revolving Credit Facility and, to a lesser extent, for general partnership purposes.

  In March 2008, TEPPCO sold $250.0 million in principal amount of 5-year senior notes, $350.0 million of 10-year senior notes and $400.0 million of 30-year senior notes. In January 2008 TEPPCO repaid $355.0 million in principal amount of the TE Products senior notes. In May 2007, TEPPCO sold $300.0 million in principal amount of its junior subordinated notes.

  For information regarding our consolidated debt obligations, see Note 14 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

- § Net proceeds from the issuance of our common units increased $73.6 million year-to-year due to increased participation in our DRIP.

- § Contributions from noncontrolling interests increased $6.8 million year-to-year primarily due to TEPPCO's issuance of 9.2 million of its units in September 2008, which generated net proceeds of $257.0 million, offset by the initial public offering of Duncan Energy Partners in February 2007, which generated proceeds of $290.5 million.

- § Cash distributions to our partners increased $79.8 million year-to-year primarily due to increases in our common units outstanding and quarterly distribution rates.

- § Distributions to noncontrolling interests increased $57.1 million year-to-year primarily due to increases in the quarterly distribution rates of Duncan Energy Partners and TEPPCO, along with an increase in TEPPCO's units outstanding.

- § The early termination and settlement of interest rate hedging derivative instruments during 2008 resulted in net cash payments of $66.5 million compared to net cash receipts of $49.1 million during the same period in 2007, which resulted in a $115.6 million decrease in financing cash flows between years.

Comparison of 2007 with 2006

Operating activities. Net cash flows provided by operating activities were $1.95 billion for 2007 compared to $1.46 billion for 2006. The $494.5 million year-to-year increase in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding distributions received from unconsolidated affiliates and cash payments for interest and taxes) increased $612.0 million year-to-year. The improvement in cash flow is generally due to increased gross operating margin and the timing of related cash collections and disbursements between periods. The $612.0 million total year-to-year increase also reflects a $42.1 million increase in cash proceeds we received from insurance claims related to certain named storms.

§ Cash distributions received from unconsolidated affiliates increased $10.5 million year-to-year primarily due to improved earnings from our Gulf of Mexico investments, which were negatively impacted during 2006 as a result of the lingering effects of Hurricanes Katrina and Rita. These increases were partially offset by decreased distributions from Seaway and MB Storage.

§ Cash payments for interest increased $128.0 million year-to-year primarily due to increased borrowings to finance our capital spending program. Our average debt balance for 2007 was $7.82 billion compared to $6.45 billion for 2006.

§ Cash payments for taxes decreased $4.7 million year-to-year.

Investing activities. Cash used in investing activities was $2.87 billion for 2007 compared to $1.97 billion for 2006. The $898.2 million year-to-year increase in cash used for investing activities was primarily due to the following:

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, increased $1.04 billion year-to-year. For additional information related to our capital spending program, see "Capital Spending" included within this Item 7.

§ Cash outlays for investments in unconsolidated affiliates increased by $225.5 million year-to-year. We contributed $216.5 million to Cameron Highway during the second quarter of 2007. Cameron Highway used these funds, along with an equal contribution from our 50% joint venture partner in Cameron Highway, to repay approximately $430.0 million of its outstanding debt.

§ Cash used for business combinations decreased $256.3 million year-to-year, of which approximately $100.0 million was for the purchase of Piceance Creek Pipeline, LLC during 2006 and $145.2 million for the Encinal acquisition during 2006. Our spending for business combinations during 2007 was limited and primarily attributable to the $35.0 million we paid to acquire the South Monco pipeline business.

§ Proceeds from the sales of assets and related transactions in 2007 were $169.1 million, primarily from the sale of our interest in MB Storage and its general partner.

§ Restricted cash increased $38.6 million (a cash outflow) year-to-year.

Financing activities. Cash provided by financing activities was $946.3 million for 2007 compared to $495.3 million for 2006. The $451.0 million year-to-year increase in cash provided by financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements increased $1.27 billion year-to-year. In May 2007, EPO sold $700.0 million in principal amount of fixed/floating unsecured junior subordinated notes ("Junior Notes B"). In September 2007, EPO sold $800.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes L") and in October 2007, EPO repaid $500.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes E").

In May 2007, TEPPCO sold $300.0 million in principal amount of fixed/floating unsecured junior subordinated notes. Additionally, in October 2007, TE Products redeemed $35.0 million principal amount of its 7.51% Senior Notes for $36.1 million and accrued interest. Net borrowings under TEPPCO's revolving credit facility decreased $84.1 million year-to-year.

For information regarding our consolidated debt obligations, see Note 14 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

§ Net proceeds from the issuance of our common units decreased $788.0 million year-to-year. We completed underwritten equity offerings in March and September of 2006 that generated net proceeds of $750.8 million reflecting the sale of 31,050,000 common units.

§ Contributions from noncontrolling interests increased $82.1 million year-to-year primarily due to the initial public offering of Duncan Energy Partners in February 2007, which generated net proceeds of $290.5 million from the sale of 14,950,000 of its common units. This increase was partially offset by TEPPCO's issuance of 5,800,000 of its common units in July 2006, which generated net proceeds of $195.1 million.

§ Cash distributions to our partners increased $114.4 million year-to-year primarily due to increases in our common units outstanding and quarterly distribution rates. Distributions to noncontrolling interests increased $39.4 million year-to-year primarily due to increases in TEPPCO's common units outstanding and quarterly distribution rates.

§ The termination and settlement of interest rate and treasury lock derivative instruments during 2007 related to our interest rate risk hedging activities resulted in net cash payments of $49.1 million.

Capital Spending

An integral part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe that we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas and/or crude oil production from resource basins such as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, Barnett Shale in North Texas, and the deepwater Gulf of Mexico.

Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestitures.

The following table summarizes our capital spending by activity for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2008	2007	2006
Capital spending for business combinations:			
Great Divide Gathering System acquisition	$ 125.2	$ --	$ --
Encinal acquisition, excluding non-cash consideration (1)	--	0.1	145.2
Piceance Basin Gathering System acquisition	--	0.4	100.0
South Monco Pipeline System acquisition	--	35.0	--
Canadian Enterprise Gas Products, Ltd. acquisition	--	--	17.7
Cenac acquisition	258.1	--	--
Horizon acquisition	87.6	--	--
Terminal assets purchased from New York LP Gas Storage, Inc.	--	--	9.9
Refined products terminal purchased from Mississippi Terminal and Marketing Inc.	--	--	5.8
Additional ownership interests in Dixie	57.1	0.4	12.9
Additional ownership interests in Tri-States and Belle Rose NGL Pipeline, LLC	19.9	--	--
Other business combinations	5.5	--	0.7
Total	553.4	35.9	292.2
Capital spending for property, plant and equipment, net: (2)			
Growth capital projects (3)	2,249.6	2,464.7	1,462.9
Sustaining capital projects (4)	262.9	241.7	204.3
Total	2,512.5	2,706.4	1,667.2
Capital spending for intangible assets:			
Acquisition of intangible assets (5)	5.8	14.5	--
Capital spending attributable to unconsolidated affiliates:			
Investments in unconsolidated affiliates (6)	62.3	230.2	25.7
Total capital spending	$ 3,134.0	$ 2,987.0	$ 1,985.1

(1) The 2006 period excludes $181.1 million of non-cash consideration paid to the seller in the form of 7,115,844 of our common units. See Note 12 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for additional information regarding our business combinations.
(2) On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. Contributions in aid of construction costs were $28.6 million, $57.6 million and $60.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.
(3) Growth capital projects either result in additional revenue streams from existing assets or expand our asset base through construction of new facilities that will generate additional revenue streams.
(4) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to and major renewals of existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues.
(5) Amount for 2008 represents the acquisition of permits for our Mont Belvieu storage facility. Amount for 2007 represents $11.2 million for the acquisition of nitric oxide credits at our Morgan’s Point Facility and $3.3 million for customer reimbursable commitments.
(6) Fiscal 2007 includes $216.5 million in cash contributions to Cameron Highway to fund our share of the repayment of its debt obligations.

Based on information currently available, we estimate our consolidated capital spending for 2009 will approximate $1.34 billion, which includes estimated expenditures of $1.11 billion for growth capital projects and acquisitions and $232.0 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our current announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements, issuance of equity, and potential divestitures of certain assets to third and/or related parties. Our forecast of capital expenditures may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast may change as a result of decisions made by management at a later date, which may include acquisitions or decisions to take on additional partners.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor that determines how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs, and although we currently intend to make the forecasted expenditures discussed above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At December 31, 2008, we had approximately $786.7 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction of our Barnett Shale natural gas pipeline projects and Meeker natural gas processing plant expansion.

Significant Ongoing Growth Capital Projects

The following table summarizes information regarding certain ongoing significant announced growth capital projects (dollars in millions). Actual costs noted for each project reflects our share of cash expenditures as of December 31, 2008, excluding capitalized interest. The current forecast amount noted for each project also reflects our share of project expenditures, excluding estimated capitalized interest.

Project Name	Estimated Date of Completion	Actual Costs	Current Forecast Total Cost
Sherman Extension Pipeline (Barnett Shale)	2009	$ 457.0	$ 489.2
Shenzi Oil Pipeline	2009	135.8	153.5
Marathon Piceance Basin pipeline projects	2009	36.6	151.3
Trinity River Basin Extension	2009	16.4	232.6
Expansion of Wilson natural gas storage facility	2010	51.1	119.6
Motiva refined products storage facility and pipeline	2010	170.1	355.0
Texas Offshore Port System	To be determined	66.0	1,200.0

Sherman Extension Pipeline (Barnett Shale). In November 2006, we announced an expansion of our Texas Intrastate System with the construction of the Sherman Extension that will transport up to 1.1 Bcf/d of natural gas from the growing Barnett Shale area of North Texas. The Sherman Extension is supported by long-term contracts with Devon Energy Corporation, the largest producer in the Barnett Shale area, and significant indications of interest from leading producers and gatherers in the Fort Worth basin, as well as other shippers on our Texas Intrastate Pipeline system. At its terminus, the new pipeline system will make deliveries into Boardwalk Pipeline Partners L.P.'s Gulf Crossing Expansion Project, which will provide export capacity for Barnett Shale natural gas production to multiple delivery points in Louisiana, Mississippi and Alabama that offer access to attractive markets in the Northeast and Southeast United States. In addition, the Sherman Extension will provide natural gas producers in East Texas and the Waha area of West Texas with access to these higher value markets through our Texas Intrastate Pipeline system. The Sherman Extension will originate near Morgan Mill, Texas and extend through the center of the current Barnett Shale development area to Sherman, Texas. In 2008, we placed into service portions of the Sherman Extension. The Sherman Extension is scheduled for final completion in March 2009.

The Barnett Shale is considered to be one of the largest unconventional natural gas resource plays in North America, covering approximately 14 counties and over seven million acres in the Fort Worth basin in North Texas. Current natural gas production is estimated at 3.4 Bcf/d from approximately 7,800 wells. Approximately 190 rigs are currently estimated to be working to develop Barnett Shale acreage in the region. According to the United States Geological Survey, the Barnett Shale has the resource potential of approximately 26 trillion cubic feet of natural gas.

Shenzi Oil Pipeline. In October 2006, we announced the execution of definitive agreements with producers to construct, own and operate an oil export pipeline that will provide firm gathering services from the BHP Billiton Plc-operated Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico. The Shenzi oil export pipeline will originate at the Shenzi Field, located in 4,300 feet of water at Green Canyon Block 653, approximately 120 miles off the coast of Louisiana. The 83-mile, 20-inch diameter pipeline will have the capacity to transport up to 230 MBPD of crude oil and will connect the Shenzi Field to our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at our Ship Shoal 332B junction platform. We own a 50% interest in the Cameron Highway Oil Pipeline and a 36% interest in the Poseidon Oil Pipeline System and operate both pipelines. The Shenzi oil export pipeline will connect to a platform being constructed by BHP Billiton Plc to develop the Shenzi Field, which is expected to commence operations during the second quarter of 2009.

Marathon Piceance Basin pipeline projects. In December 2006, we entered into a long-term contract with Marathon Oil Company ("Marathon") to provide a range of midstream energy services, including natural gas gathering, compression, treating and processing, for Marathon's natural gas production in the Piceance Basin of northwest Colorado. Under the terms of the contract, we are constructing 50 miles of gathering lines and related assets to connect Marathon's multi-well drilling sites, production from which is expected to peak at approximately 180 MMcf/d, to our Piceance Creek Gathering System. From there the natural gas will be delivered to our Meeker natural gas processing facility.

Trinity River Basin Extension. In August 2008, we announced the development of a new 40-mile supply lateral that will extend from the Trinity River Basin north of Arlington, Texas to an interconnect with the Sherman Extension pipeline near Justin, Texas to accommodate growing natural gas production from the Barnett Shale. This new pipeline will consist of 30-inch and 36-inch diameter pipeline designed to provide up to 1.0 Bcf/d of natural gas takeaway capacity for producers in Tarrant and Denton counties. This new pipeline will also have a lateral to provide transportation services for natural gas produced from the Newark East field in Wise County. These new pipeline laterals are anchored by long-term agreements with major producers and are expected to be in-service by year end 2009.

Expansion of Wilson natural gas storage facility. We are developing a new natural gas storage cavern located on the Boling Salt Dome near Boling, Texas. The cavern is designed to store approximately 7.9 Bcf of natural gas, of which approximately 5.0 Bcf will be working gas capacity and 2.9 Bcf will be the base gas requirements needed to support minimum pressures. This expansion project was approved by the Texas Railroad Commission and is projected to commence operations in 2010. We expect to secure binding precedent agreements on all capacity before the cavern commences operations.

Motiva refined products storage facility and pipeline. In December 2006, we signed an agreement with Motiva for us to construct and operate a new refined products storage facility to support the expansion of Motiva's refinery in Port Arthur, Texas. Under the terms of the agreement, we are constructing a 5.4 million barrel refined products storage facility for gasoline and distillates. The agreement also provides for a 15-year throughput and dedication of volume, which will commence upon completion of the refinery expansion or July 1, 2010, whichever comes first. The project includes the construction of 20 storage tanks, five 5.4-mile product pipelines connecting the storage facility to Motiva's refinery, 21,000 horsepower of pumping capacity, and distribution pipeline connections to the Colonial, Explorer and Magtex pipelines.

As a part of a separate but complementary initiative, we are constructing an 11-mile, 20-inch pipeline to connect the new storage facility in Port Arthur to our refined products terminal in Beaumont, Texas, which is one of the primary origination facilities for our Products Pipeline System. These projects will facilitate connections to additional markets through the Colonial, Explorer and Magtex pipeline systems and provide the Motiva refinery with access to our pipeline system.

Texas Offshore Port System (TOPS and PACE). In August 2008, we, together with Oiltanking, announced the formation of a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. We and Oiltanking each owned, through our respective subsidiaries, a two-thirds and one-third interest in the joint venture, respectively. For additional information regarding this joint venture and its capital projects, see "Recent Developments – Texas Offshore Port System" within this Item 7.

Pipeline Integrity Costs

Our NGL, crude oil, refined products, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL, crude oil, refined products and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs.

In April 2002, a subsidiary of ours acquired several midstream energy assets located in Texas and New Mexico from El Paso Corporation ("El Paso"). These assets included the Texas Intrastate System and the Carlsbad Gathering Systems. With respect to such assets, El Paso agreed to indemnify our subsidiary for any pipeline integrity costs it incurred (whether paid or payable) for five years following the acquisition date. The indemnity provisions did not take effect until such costs exceeded $3.3 million annually; however, the amount reimbursable by El Paso was capped at $50.2 million in the aggregate. In 2007 and 2006, we recovered $31.1 million and $13.7 million, respectively from El Paso related to our 2006 and 2005 expenditures. During 2007, we received a final amount of $5.4 million from El Paso related to this indemnity.

The following table summarizes our accrued pipeline integrity costs, net of indemnity payments from El Paso, for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Expensed	$ 55.4	$ 51.9	$ 37.5
Capitalized	86.2	78.9	50.4
Total	$ 141.6	$ 130.8	$ 87.9

We expect our cash outlay for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $127.8 million in 2009.

Critical Accounting Policies and Estimates

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our supplemental financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following describes the estimation risk currently underlying our most significant financial statement items:

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.

Examples of such circumstances include:

- § changes in laws and regulations that limit the estimated economic life of an asset;
- § changes in technology that render an asset obsolete;
- § changes in expected salvage values; or
- § changes in the forecast life of applicable resource basins, if any.

At December 31, 2008 and 2007, the net book value of our property, plant and equipment was $16.73 billion and $14.31 billion, respectively. We recorded $595.9 million, $515.7 million and $433.7 million in depreciation expense for the years ended December 31, 2008, 2007 and 2006, respectively.

For additional information regarding our property, plant and equipment, see Notes 2 and 10 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

Measuring recoverability of long-lived assets and equity method investments

In general, long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, NGLs, crude oil or refined products. Long-lived assets with recorded values that are not expected to be recovered through expected future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the existing asset. Our estimates of such undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated salvage values. An impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows. Those assumptions also include usage of probabilities for a range of possible outcomes, market values and replacement cost estimates.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible loss in value of the investment other than a temporary decline. Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee's industry. Equity method investments with carrying values that are not expected to be recovered through expected future cash flows are written down to their estimated fair values. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flows expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment. A significant change in these underlying assumptions could result in our recording an impairment charge.

We recognized a non-cash asset impairment charge related to property, plant and equipment of $0.1 million in 2006, which is reflected as a component of operating costs and expenses. No such asset impairment charges were recorded in 2008 or 2007.

During 2007, we evaluated our equity method investment in Nemo for impairment. As a result of this evaluation, we recorded a $7.0 million non-cash impairment charge that is a component of equity in earnings from unconsolidated affiliates for the year ended December 31, 2007. Similarly, during the year ended December 31, 2006, we evaluated our equity method investment in Neptune for impairment and recorded a $7.4 million non-cash impairment charge. During 2008, there were no such impairment charges.

For additional information regarding impairment charges associated with our long-lived assets and equity method investments, see Notes 2 and 11 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

Amortization methods and estimated useful lives of qualifying intangible assets

The specific, identifiable intangible assets of a business enterprise depend largely upon the nature of its operations. Potential intangible assets include intellectual property, such as technology, patents, trademarks and trade names, customer contracts and relationships, and non-compete agreements, as well as other intangible assets. The method used to value each intangible asset will vary depending upon the nature of the asset, the business in which it is utilized, and the economic returns it is generating or is expected to generate.

Our customer relationship intangible assets primarily represent the customer base we acquired in connection with business combinations and asset purchases. The value we assigned to these customer relationships is being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful life of each resource base is based on a number of factors, including reserve estimates, the economic viability of production and exploration activities and other industry factors.

Our contract-based intangible assets represent the rights we own arising from discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement or the natural gas transportation contracts on our Val Verde and Jonah systems. A contract-based intangible asset with a finite life is amortized over its estimated useful life (or term), which is the period over which the asset is expected to contribute directly or indirectly to the cash flows of an entity. Our estimates of useful life are based on a number of factors, including:

§ the expected useful life of the related tangible assets (e.g., fractionation facility, pipeline or other asset, etc.);

§ any legal or regulatory developments that would impact such contractual rights; and

§ any contractual provisions that enable us to renew or extend such agreements.

If our underlying assumptions regarding the estimated useful life of an intangible asset change, then the amortization period for such asset would be adjusted accordingly. Additionally, if we determine that an intangible asset's unamortized cost may not be recoverable due to impairment; we may be required to reduce the carrying value and the subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2008 and 2007, the carrying value of our intangible asset portfolio was $1.18 billion and $1.21 billion, respectively. We recorded $130.0 million, $125.2 million and $122.1 million in amortization expense associated with our intangible assets for the years ended December 31, 2008, 2007 and 2006, respectively.

For additional information regarding our intangible assets, see Notes 2 and 13 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

Methods we employ to measure the fair value of goodwill

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values. We do not amortize goodwill; however, we test our goodwill (at the reporting unit level) for impairment during the second quarter of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit's fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit.

Such assumptions include:

§ discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins and transportation volumes;

§ long-term growth rates for cash flows beyond the discrete forecast period; and

§ appropriate discount rates.

If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings is required to reduce the carrying value of goodwill to its implied fair value. At December 31, 2008 and 2007, the carrying value of our goodwill was $2.02 billion and $1.81 billion, respectively. We did not record any goodwill impairment charges during the periods presented.

For additional information regarding our goodwill, see Notes 2 and 13 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

Our revenue recognition policies and use of estimates for revenues and expenses

In general, we recognize revenue from our customers when all of the following criteria are met:

§ persuasive evidence of an exchange arrangement exists;

§ delivery has occurred or services have been rendered;

§ the buyer's price is fixed or determinable; and

§ collectability is reasonably assured.

We record revenue when sales contracts are settled (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). We record any necessary allowance for doubtful accounts as required by our established policy.

Our use of certain estimates for revenues and expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the timing to compile actual billing information and receiving third-party data needed to record transactions for financial reporting purposes. One example of such use of estimates is the accrual of an estimate of processing plant revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related plant operating information for the subject period). These estimates reverse in the following month and are offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, we include one month of certain estimated data in our results of operations. Such estimates are generally based on actual volume and price data through the first part of the month and estimated for the remainder of the month, adjusted accordingly for any known or expected changes in volumes or rates through the end of the month.

If the basis of our estimates proves to be substantially incorrect, it could result in material adjustments in results of operations between periods. On an ongoing basis, we review our estimates based on currently available information. Changes in facts and circumstances may result in revised estimates and could affect our reported supplemental financial statements and accompanying notes.

Reserves for environmental matters

Each of our business segments is subject to federal, state and local laws and regulations governing environmental quality and pollution control. Such laws and regulations may, in certain instances, require us to remediate current or former operating sites where specified substances have been released or disposed of. We accrue reserves for environmental matters when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our assessments are based on studies, as well as site surveys, to determine the extent of any environmental damage and the necessary requirements to remediate this damage. Future environmental developments, such as increasingly strict environmental laws and additional claims for damages to property, employees and other persons resulting from current or past operations, could result in substantial additional costs beyond our current reserves. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2008, none of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable.

At December 31, 2008 and 2007, we had liabilities for environmental remediation of $22.3 million and $30.5 million, respectively, which were derived from a range of reasonable estimates based upon studies and site surveys. We follow the provisions of American Institute of Certified Public Accountants Statement of Position 96-1, which provides key guidance on recognition, measurement and disclosure of remediation liabilities. We have recorded our best estimate of the cost of remediation activities. See Item 3 of our Annual Report on Form 10-K for recent developments regarding environmental matters.

Natural gas imbalances

In the natural gas pipeline transportation business, imbalances frequently result from differences in natural gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. The vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are on-going and take place over several months. In some cases, settlements of imbalances accumulated over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. As a result, for gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2008 and 2007, our imbalance receivables, net of allowance for doubtful accounts, were $63.4 million and $73.9 million, respectively, and are reflected as a component of “Accounts and notes receivable – trade” on our Supplemental Consolidated Balance Sheets included under Exhibit 99.2 of this Current Report on Form 8-K. At December 31, 2008 and 2007, our imbalance payables were $50.8 million and $48.7 million, respectively, and are reflected as a component of “Accrued product payables” on our Supplemental Consolidated Balance Sheets included under Exhibit 99.2 of this Current Report on Form 8-K.

Other Items

Duncan Energy Partners Transactions

Duncan Energy Partners was formed in September 2006 and did not acquire any assets prior to February 5, 2007, which was the date it completed its initial public offering of 14,950,000 common units and acquired controlling interests in certain midstream energy businesses of EPO. The business purpose of Duncan Energy Partners is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates under common control. Duncan Energy Partners is engaged in the business of fractionating NGLs; transporting and storing NGLs and petrochemical products; and gathering, transporting, storing and marketing of natural gas.

At December 31, 2008, Duncan Energy Partners is owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP Operating Partnership L.P. ("DEP OLP"), a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business.

At December 31, 2008, EPO owned approximately 74% of Duncan Energy Partners' limited partner interests and 100% of its general partner.

DEP I Midstream Businesses. On February 5, 2007, EPO contributed a 66% controlling equity interest in each of the DEP I Midstream Businesses (defined below) to Duncan Energy Partners in a dropdown of assets. EPO retained the remaining 34% equity interest in each of the DEP I Midstream Businesses. The DEP I Midstream Businesses consist of (i) Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"); (ii) Acadian Gas, LLC ("Acadian Gas"); (iii) Enterprise Lou-Tex Propylene Pipeline L.P. ("Lou-Tex Propylene"), including its general partner; (iv) Sabine Propylene Pipeline L.P. ("Sabine Propylene'), including its general partner; and (v) South Texas NGL Pipelines, LLC ("South Texas NGL").

As consideration for controlling equity interests in the DEP I Midstream Businesses and reimbursement for capital expenditures related to these businesses, Duncan Energy Partners distributed to EPO (i) $260.6 million of the $290.5 million of net proceeds from its initial public offering to EPO, (ii) $198.9 million in borrowings under its revolving credit facility and (iii) a net 5,351,571 common units of Duncan Energy Partners. See Note 14 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for information regarding the debt obligations of Duncan Energy Partners.

DEP II Midstream Businesses. On December 8, 2008, Duncan Energy Partners entered into a Purchase and Sale Agreement (the "DEP II Purchase Agreement") with EPO and Enterprise GTM Holdings L.P. ("Enterprise GTM," a wholly owned subsidiary of EPO). Pursuant to the DEP II Purchase Agreement, DEP OLP acquired 100% of the membership interests in Enterprise Holding III, LLC ("Enterprise III") from Enterprise GTM, thereby acquiring a 66% general partner interest in Enterprise GC, a 51% general partner interest in Enterprise Intrastate and a 51% membership interest in Enterprise Texas. Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the "DEP II Midstream Businesses." EPO was the sponsor of this second dropdown transaction. Enterprise GTM retained the remaining limited partner and member interests in the DEP II Midstream Businesses.

As consideration for controlling equity interests in the DEP II Midstream Businesses, EPO received $280.5 million in cash and 37,333,887 Class B limited partner units having a market value of $449.5 million from Duncan Energy Partners. The Class B limited partner units automatically converted to common units of Duncan Energy Partners on February 1, 2009. The total value of the consideration provided to EPO and Enterprise GTM was $730.0 million. The cash portion of the consideration provided by Duncan Energy Partners in this dropdown transaction was derived from borrowings under a term loan. See Note 14 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for information regarding the debt obligations of Duncan Energy Partners.

Generally, the DEP II dropdown transaction documents provide that to the extent that the DEP II Midstream Businesses generate cash sufficient to pay distributions to their partners or members, such cash will be distributed to Enterprise III (a wholly owned by Duncan Energy Partners) and Enterprise GTM (our wholly owned subsidiary) in an amount sufficient to generate an aggregate annualized return on their respective investments of 11.85%. Distributions in excess of this amount will be distributed 98% to Enterprise GTM and 2% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102% of 11.85%, or 12.087%.

Duncan Energy Partners paid a pro rated cash distribution of $0.1115 per unit on the Class B units with respect to the fourth quarter of 2008.

Insurance Matters

We participate as a named insured in EPCO’s insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of damages or interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

For windstorm events such as hurricanes and tropical storms, EPCO’s deductible for onshore physical damage is $10.0 million per storm. For offshore assets, the windstorm deductible is $10.0 million per storm plus a one-time $15.0 million aggregate deductible per policy period. For non-windstorm events, EPCO’s deductible for onshore and offshore physical damage is $5.0 million per occurrence. In meeting the deductible amounts, property damage costs are aggregated for EPCO and its affiliates, including us. Accordingly, our exposure with respect to the deductibles may be equal to or less than the stated amounts depending on whether other EPCO or affiliate assets are also affected by an event.

To qualify for business interruption coverage in connection with a windstorm event, covered assets must be out-of-service in excess of 60 days for onshore assets and 75 days for offshore assets. To qualify for business interruption coverage in connection with a non-windstorm event, covered onshore and offshore assets must be out-of-service in excess of 60 days.

In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. As a result of our allocated share of EPCO’s insurance deductibles for windstorm coverage, we expensed a combined $49.1 million of repair costs for property damage in connection with these two storms. We expect to file property damage insurance claims to the extent repair costs exceed deductible amounts. Due to the recent nature of these storms, we are still evaluating the total cost of repairs and the potential for business interruption claims on certain assets.

See Note 21 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for more information regarding insurance matters.

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2008 (dollars in millions).

Contractual Obligations	Total	Payment or Settlement due by Period: Less than 1 year	1-3 years	4-5 years	More than 5 years
Scheduled maturities of long-term debt (1)	$ 11,562.8	$ --	$ 1,488.3	$ 3,734.3	$ 6,340.2
Estimated cash payments for interest (2)	$ 11,976.0	$ 691.5	$ 1,287.6	$ 1,036.5	$ 8,960.4
Operating lease obligations (3)	$ 388.3	$ 44.9	$ 75.8	$ 66.9	$ 200.7
Purchase obligations: (4)					
Product purchase commitments:					
Estimated payment obligations:					
Crude oil	$ 161.2	$ 161.2	$ --	$ --	$ --
Refined products	$ 1.6	$ 1.6	$ --	$ --	$ --
Natural gas	$ 5,225.1	$ 323.3	$ 1,150.1	$ 1,148.6	$ 2,603.1
NGLs	$ 1,923.8	$ 969.9	$ 272.6	$ 272.5	$ 408.8
Petrochemicals	$ 1,746.2	$ 685.6	$ 624.4	$ 268.5	$ 167.7
Other	$ 66.7	$ 24.2	$ 14.6	$ 12.5	$ 15.4
Underlying major volume commitments:					
Crude oil (in MBbls)	3,404	3,404	--	--	--
Refined products (in MBbls)	28	28	--	--	--
Natural gas (in BBtus)	981,955	56,650	209,075	214,730	501,500
NGLs (in MBbls)	56,622	23,576	9,446	9,440	14,160
Petrochemicals (in MBbls)	67,696	24,949	23,848	11,665	7,234
Service payment commitments (5)	$ 534.4	$ 57.3	$ 100.8	$ 93.1	$ 283.2
Capital expenditure commitments (6)	$ 786.7	$ 786.7	$ --	$ --	$ --
Other long-term liabilities, as reflected in our Consolidated Balance Sheet (7)	$ 110.5	$ --	$ 26.1	$ 15.3	$ 69.1
Total	$ 34,483.3	$ 3,746.2	$ 5,040.3	$ 6,648.2	$ 19,048.6

(1) Represents our scheduled future maturities of consolidated debt obligations. For additional information on our consolidated debt obligations, see Note 14 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

(2) Our estimated cash payments for interest are based on the principal amount of consolidated debt obligations outstanding at December 31, 2008. With respect to variable-rate debt, we applied the weighted-average interest rates paid during 2008. See Note 14 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for information regarding variable interest rates charged in 2008 under our credit agreements. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements in place at December 31, 2008. See Note 7 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for information regarding our interest rate swap agreements. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our $550.0 million Junior Notes A (due August 2066), $682.7 million Junior Notes B (due January 2068) and the TEPPCO $300.0 million Junior Subordinated Notes (due June 2067). Our estimated cash payments for interest assume that Junior Note obligations are not called prior to maturity.

(3) Primarily represents operating leases for (i) underground caverns for the storage of natural gas and NGLs, (ii) leased office space with affiliates of EPCO, (iii) a railcar unloading terminal in Mont Belvieu, Texas and (iv) land held pursuant to right-of-way agreements.

(4) Represents enforceable and legally binding agreements to purchase goods or services based on the contractual price under terms of each agreement at December 31, 2008.

(5) Represents future payment commitments for services provided by third-parties.

(6) Represents short-term unconditional payment obligations relating to our capital projects and those of our unconsolidated affiliates to vendors for services rendered or products purchased.

(7) Other long-term liabilities as reflected on our Supplemental Consolidated Balance Sheet included under Exhibit 99.2 of this Current Report on Form 8-K at December 31, 2008 primarily represent (i) asset retirement obligations expected to settled in periods beyond 2012, (ii) reserves for environmental remediation costs that are expected to settle beginning in 2009 and afterwards and (iii) guarantee agreements relating to Centennial.

For additional information regarding our significant contractual obligations involving operating leases and purchase obligations, see Note 20 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

Off-Balance Sheet Arrangements

Except for the following information regarding debt obligations of certain unconsolidated affiliates, we have no off-balance sheet arrangements, as described in Item 303(a)(4)(ii) of Regulation S-K, that have or are reasonably expected to have a material current or future effect on our financial position, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources. The following information summarizes the significant terms of such unconsolidated debt obligations.

Poseidon. At December 31, 2008, Poseidon's debt obligations consisted of $109.0 million outstanding under its $150.0 million revolving credit facility. Amounts borrowed under this facility mature in May 2011 and are secured by substantially all of Poseidon's assets.

Evangeline. At December 31, 2008, Evangeline's debt obligations consisted of (i) $8.2 million in principal amount of 9.90% fixed rate Series B senior secured notes due December 2010 and (ii) a $7.5 million subordinated note payable. Duncan Energy Partners had $1.0 million of letters of credit outstanding on December 31, 2008 that were furnished on behalf of Evangeline's debt.

Centennial. At December 31, 2008, Centennial's debt obligations consisted of $129.9 million borrowed under a master shelf loan agreement. Borrowings under the master shelf agreement mature in May 2024 and are collateralized by substantially all of Centennial's assets and severally guaranteed by Centennial's owners. Specifically, we and our joint venture partner in Centennial have each guaranteed one-half of Centennial's debt obligations. If Centennial defaults on its debt obligations, our estimated payment obligation is $65.0 million at December 31, 2008.

Summary of Related Party Transactions

The following table summarizes our related party transactions for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Revenues from consolidated operations			
EPCO and affiliates	$ --	$ 0.2	$ 55.8
Energy Transfer Equity and subsidiaries	618.5	294.5	--
Unconsolidated affiliates	396.9	290.5	304.9
Total	$ 1,015.4	$ 585.2	$ 360.7
Cost of sales			
EPCO and affiliates	$ 40.1	$ 34.0	$ 75.3
Energy Transfer Equity and subsidiaries	173.9	26.9	--
Unconsolidated affiliates	58.6	41.0	45.2
Total	$ 272.6	$ 101.9	$ 120.5
Operating costs and expenses			
EPCO and affiliates	$ 423.1	$ 353.7	$ 328.5
Energy Transfer Equity and subsidiaries	18.3	8.3	--
Cenac and affiliates	45.4	--	--
Unconsolidated affiliates	(2.4)	--	(5.2)
Total	$ 484.4	$ 362.0	$ 323.3
General and administrative expenses			
EPCO and affiliates	$ 91.0	$ 82.6	$ 63.7
Cenac and affiliates	2.9	--	--
Unconsolidated affiliates	(0.1)	--	--
Total	$ 93.8	$ 82.6	$ 63.7
Other income (expense)			
EPCO and affiliates	$ (0.3)	$ (0.2)	$ 0.7
Unconsolidated affiliates	--	--	0.3
Total	$ (0.3)	$ (0.2)	$ 1.0

For additional information regarding our related party transactions, see Note 17 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K. For information regarding certain business relationships and related transactions, see Item 13 of our Annual Report on Form 10-K.

We have an extensive and ongoing relationship with EPCO and its affiliates. Our revenues from EPCO and affiliates are primarily associated with sales of NGL products. Our expenses with EPCO and affiliates are primarily due to (i) reimbursements we pay EPCO in connection with an administrative services agreement (the "ASA") and (ii) purchases of NGL products. Enterprise GP Holdings acquired noncontrolling ownership interests in both LE GP and Energy Transfer Equity in May 2007. As a result of this transaction, ETE GP and Energy Transfer Equity became related parties to us.

Many of our unconsolidated affiliates perform supporting or complementary roles to our consolidated business operations. The majority of our revenues from unconsolidated affiliates relate to natural gas sales to a Louisiana affiliate. The majority of our expenses with unconsolidated affiliates pertain to payments we make to K/D/S Promix, L.L.C. for NGL transportation, storage and fractionation services.

On February 5, 2007, our consolidated subsidiary, Duncan Energy Partners, completed an underwritten initial public offering of its common units. Duncan Energy Partners was formed in September 2006 as a Delaware limited partnership to, among other things, acquire ownership interests in certain of our midstream energy businesses. For additional information regarding Duncan Energy Partners, see "Other Items – Duncan Energy Partners Transactions" within this section.

Non-GAAP Reconciliations

The following table presents a reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes and the cumulative effect of change in accounting principle (dollars in millions):

	For the Year the Ended December 31,		
	2008	**2007**	**2006**
Total segment gross operating margin	$ 2,609.0	$ 1,964.4	$ 1,770.9
Adjustments to reconcile total gross operating margin			
to operating income:			
Depreciation, amortization and accretion in			
operating costs and expenses	(725.4)	(647.9)	(556.9)
Operating lease expense paid by EPCO	(2.0)	(2.1)	(2.1)
Gain from asset sales and related transactions in			
operating costs and expenses	4.0	7.8	5.1
General and administrative costs	(137.2)	(127.2)	(95.9)
Operating income	1,748.4	1,195.0	1,121.1
Other expense, net	(528.5)	(341.3)	(313.0)
Income before provision for income taxes and the			
cumulative effect of change in accounting principle	$ 1,219.9	$ 853.7	$ 808.1

EPCO subleases to us 100 railcars for $1 per year (the "retained leases"). These subleases are part of the ASA that we executed with EPCO in connection with our formation in 1998. EPCO holds this equipment pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. We record the full value of such lease payments made by EPCO as a non-cash related party operating expense, with the offset to equity recorded as a general contribution to our partnership. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases. We exercised our election under the retained leases to purchase a cogeneration unit in December 2008 for $2.3 million. For additional information regarding the ASA and the retained leases, see Item 13 of our Annual Report on Form 10-K.

Recent Accounting Pronouncements

The accounting standard setting bodies have recently issued the following accounting guidance that will affect our future financial statements:

- § SFAS 141(R), Business Combinations;
- § FASB Staff Position SFAS 142-3, Determination of the Useful Life of Intangible Assets;
- § SFAS 157, Fair Value Measurements;
- § SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – An amendment of ARB 51;
- § SFAS 161, Disclosures about Derivative Instruments and Hedging Activities – An Amendment of SFAS 133;
- § Emerging Issues Task Force (“EITF”) 08-6, Equity Method Investment Accounting Considerations; and
- § EITF 07-4, Application of the Two Class Method Under SFAS 128, Earnings Per Share, to Master Limited Partnerships.

For additional information regarding recent accounting pronouncements, see Note 3 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K.

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

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. We may use derivative instruments (e.g., futures, forwards, swaps, options and other derivative instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the types of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt obligations and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates.

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

The following table presents gains (losses) recorded in net income attributable to our interest rate risk and commodity risk hedging transactions for the periods indicated. These amounts do not present the corresponding gains (losses) attributable to the underlying hedged items (dollars in millions).

	For the Year Ended December 31,		
	2008	2007	2006
Interest Rate Risk Hedging Portfolio:			
Enterprise Products Partners (excluding Duncan Energy Partners):			
Ineffective portion of cash flow hedges	$ (0.1)	$ --	$ --
Reclassification of cash flow hedge amounts from AOCI, net	(0.5)	5.5	4.2
Loss from treasury lock cash flow hedge	(3.6)	--	--
Other gains (losses) from derivative transactions	9.4	(3.7)	3.4
Duncan Energy Partners:			
Ineffective portion of cash flow hedges	--	(0.2)	--
Reclassification of cash flow hedge amounts from AOCI, net	(2.0)	0.4	--
Total hedging gains, net, in consolidated interest expense	$ 3.2	$ 2.0	$ 7.6
Commodity Risk Hedging Portfolio:			
Enterprise Products Partners:			
Reclassification of cash flow hedge amounts from AOCI, net - natural gas marketing activities	$ (30.2)	$ (3.3)	$ (1.3)
Reclassification of cash flow hedge amounts from AOCI, net - crude oil marketing activities	(37.9)	(1.6)	0.2
Reclassification of cash flow hedge amounts from AOCI, net - NGL and petrochemical operations	(28.2)	(4.6)	13.9
Other gains (losses) from derivative transactions	29.4	(20.5)	(2.4)
Total hedging gains (losses), net, in consolidated operating costs and expenses	$ (66.9)	$ (30.0)	$ 10.4

The following table provides additional information regarding derivative assets and derivative liabilities included in our Supplemental Consolidated Balance Sheets included under Exhibit 99.2 of this Current Report on Form 8-K at the dates indicated (dollars in millions):

	December 31, 2008	December 31, 2007
Current assets:		
Derivative assets:		
Interest rate risk hedging portfolio	$ 7.8	$ 0.2
Commodity risk hedging portfolio	201.5	10.8
Foreign currency risk hedging portfolio	9.3	1.3
Total derivative assets – current	$ 218.6	$ 12.3
Other assets:		
Interest rate risk hedging portfolio	$ 38.9	$ 14.7
Total derivative assets – long-term	$ 38.9	$ 14.7
Current liabilities:		
Derivative liabilities:		
Interest rate risk hedging portfolio	$ 5.9	$ 47.5
Commodity risk hedging portfolio	296.9	48.9
Foreign currency risk hedging portfolio	0.1	--
Total derivative liabilities – current	$ 302.9	$ 96.4
Other liabilities:		
Interest rate risk hedging portfolio	$ 3.9	$ 3.1
Commodity risk hedging portfolio	0.2	--
Total derivative liabilities– long-term	$ 4.1	$ 3.1

The following table presents gains (losses) recorded in other comprehensive income (loss) for cash flow hedges associated with our interest rate risk, commodity risk and foreign currency risk hedging portfolios. These amounts do not present the corresponding gains (losses) attributable to the underlying hedged items (dollars in millions).

	For the Year Ended December 31, 2008	2007	2006
Interest Rate Risk Hedging Portfolio:			
Enterprise Products Partners (excluding Duncan Energy Partners):			
Gains (losses) on cash flow hedges	$ (47.6)	$ (5.6)	$ 11.0
Reclassification of cash flow hedge amounts to net income, net	0.5	(5.5)	(4.2)
Duncan Energy Partners:			
Losses on cash flow hedges	(8.0)	(3.3)	--
Reclassification of cash flow hedge amounts to net income, net	2.0	(0.3)	--
Total interest rate risk hedging gains (losses), net	(53.1)	(14.7)	6.8
Commodity Risk Hedging Portfolio:			
Enterprise Products Partners:			
Natural gas marketing activities:			
Gains (losses) on cash flow hedges	(30.6)	(3.1)	(1.0)
Reclassification of cash flow hedge amounts to net income, net	30.2	3.3	1.3
Crude oil marketing activities:			
Gains (losses) on cash flow hedges	(19.3)	(21.0)	1.0
Reclassification of cash flow hedge amounts to net income, net	37.9	1.6	(0.2)
NGL and petrochemical operations:			
Gains (losses) on cash flow hedges	(120.3)	(22.8)	9.9
Reclassification of cash flow hedge amounts to net income, net	28.2	4.6	(13.9)
Total commodity risk hedging losses, net	(73.9)	(37.4)	(2.9)
Foreign Currency Risk Hedging Portfolio:			
Gains on cash flow hedges	9.3	1.3	--
Total foreign currency risk hedging gains, net	9.3	1.3	--
Total cash flow hedge amounts in other comprehensive income (loss)	$ (117.7)	$ (50.8)	$ 3.9

The following information summarizes the principal elements of our interest rate risk, commodity risk and foreign currency risk hedging portfolios. For amounts recorded in net income and other comprehensive income and on our balance sheet related to our consolidated hedging activities, please refer to the preceding tables.

Interest Rate Risk Hedging Portfolio

Our interest rate exposure results from variable and fixed rate borrowings under various debt agreements. The following information summarizes significant components of our interest rate risk hedging portfolio:

Fair value hedges – interest rate swaps

We manage a portion of our interest rate exposure by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. At December 31, 2008, we had four interest rate swap agreements outstanding having an aggregate notional value of $400.0 million that were accounted for as fair value hedges. The aggregate fair value of these interest rate swaps at December 31, 2008, was $46.7 million (an asset), with an offsetting increase in the fair value of the underlying debt. There were eleven interest rate swaps outstanding at December 31, 2007 having an aggregate fair value of $12.9 million (an asset).

The following table summarizes our interest rate swaps outstanding at December 31, 2008.

Hedged Fixed Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Value
Senior Notes C, 6.375% fixed rate, due Feb. 2013	1	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.015%	$100.0 million
Senior Notes G, 5.60% fixed rate, due Oct. 2014	3	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 5.297%	$300.0 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these interest rate swaps as fair value hedges under SFAS 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in the fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

The following table shows the effect of hypothetical price movements on the estimated fair value of our interest rate swap portfolio and the related change in fair value of the underlying debt at the dates indicated (dollars in millions).

Scenario	Resulting Classification	Swap Fair Value at December 31, 2007	Swap Fair Value at December 31, 2008	Swap Fair Value at February 3, 2009
FV assuming no change in underlying interest rates	*Asset*	$ 12.9	$ 46.7	$ 36.3
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(7.4)	42.4	31.1
FV assuming 10% decrease in underlying interest rates	*Asset*	33.1	51.1	41.5

The fair value of the interest rate swaps excludes related hedged amounts we have recorded in earnings. The change in fair value between December 31, 2008 and February 3, 2009 is primarily due to an increase in market interest rates relative to the interest rates used to determine the fair value of our derivative instruments at December 31, 2008. The underlying floating LIBOR forward interest rate curve used to determine the February 3, 2009 fair values ranged from approximately 1.3% to 3.8% using 6-month reset periods ranging from February 2008 to March 2014.

Cash flow hedges – interest rate swaps (excluding Duncan Energy Partners)

Our interest rate exposure results from variable and fixed rate borrowings under various debt agreements. At December 31, 2007, we had interest rate swap agreements outstanding having an aggregate notional value of $200.0 million and a fair value (an asset) of $0.3 million accounted for as cash flow hedges. These swap agreements settled in January 2008, and there are currently no swap agreements outstanding accounted for as cash flow hedges.

Cash flow hedges – treasury locks

We may enter into treasury rate lock transactions ("treasury locks") to hedge U.S. treasury rates related to its anticipated issuances of debt. Each of our treasury lock transactions was designated as a cash flow hedge. Gains or losses on the termination of such instruments are reclassified into net income (as a component of interest expense) using the effective interest method over the estimated term of the underlying fixed-rate debt. At December 31, 2008, we had no treasury lock derivative instruments outstanding. At December 31, 2007, the aggregate notional value of our treasury lock derivative instruments was $1.20 billion, which had a total fair value (a liability) of $44.9 million. We terminated a number of treasury lock derivative instruments during 2008 and 2007. These terminations resulted in realized losses of $92.5 million in 2008 and gains of $48.8 million in 2007.

We expect to reclassify $4.2 million of cumulative net losses from our interest rate risk cash flow hedges into net income (as an increase to interest expense) during 2009.

Cash flow hedges – Duncan Energy Partners' interest rate swaps

At December 31, 2008, Duncan Energy Partners had interest rate swap agreements outstanding having an aggregate notional value of $175.0 million. These swaps were accounted for as cash flow hedges. The purpose of these derivative instruments is to reduce the sensitivity of Duncan Energy Partners' earnings to the variable interest rates charged under its revolving credit facility. The aggregate fair value of these interest rate swaps at December 31, 2008 and 2007 was a liability of $9.8 million and $3.8 million, respectively. Duncan Energy Partners expects to reclassify $6.0 million of cumulative net losses from its interest rate risk cash flow hedges into net income (as an increase to interest expense) during 2009. The following table summarizes Duncan Energy Partners' interest rate swaps outstanding at December 31, 2008.

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
DEP I Revolving Credit Facility, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	1.47% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

As cash flow hedges, any increase or decrease in fair value (to the extent effective) would be recorded in other comprehensive income (loss) and amortized into earnings based on the settlement period hedged. Any ineffectiveness is recorded directly into earnings as an increase in interest expense.

The following table shows the effect of hypothetical price movements on the estimated fair value of Duncan Energy Partners' interest rate swap portfolio (dollars in millions).

		Swap Fair Value at		
Scenario	Resulting Classification	December 31, 2007	December 31, 2008	February 3, 2009
FV assuming no change in underlying interest rates	*Liability*	$ (3.8)	$ (9.8)	$ (9.4)
FV assuming 10% increase in underlying interest rates	*Liability*	(2.2)	(9.4)	(9.0)
FV assuming 10% decrease in underlying interest rates	*Liability*	(5.3)	(10.2)	(9.8)

Commodity Risk Hedging Portfolio

Our commodity risk hedging portfolio was impacted by a significant decline in natural gas and crude oil prices during the second half of 2008. As a result of the global recession, commodity prices have continued to be volatile during the first quarter of 2009. We may experience additional losses related to our commodity risk hedging portfolio in 2009.

The prices of natural gas, NGLs, crude oil and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity derivative instruments.

The primary purpose of our commodity risk management activities is to reduce our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL and crude oil production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs, crude oil or certain petrochemical products. From time to time, we inject natural gas into storage and may utilize hedging instruments to lock in the value of its inventory positions. The commodity derivative instruments we utilize are settled in cash.

We have segregated our commodity derivative instruments portfolio between those derivative instruments utilized in connection with our natural gas marketing activities, our crude oil marketing activities and our NGL and petrochemical operations.

A significant number of the derivative instruments in this portfolio hedge the purchase of physical natural gas. If natural gas prices fall below the price stipulated in such derivative instruments, we recognize a liability for the difference; however, if prices partially or fully recover, this liability would be reduced or eliminated, as appropriate. Our restricted cash balance at December 31, 2008 was $203.8 million in order to meet commodity exchange deposit requirements and the negative change in the fair value of our natural gas hedge positions.

Natural gas marketing activities

At December 31, 2008 and 2007, the aggregate fair value of those derivative instruments utilized in connection with our natural gas marketing activities was an asset of $6.5 million and a liability of $0.3 million, respectively. Almost all of the derivative instruments within this portion of the commodity derivative instruments portfolio are accounted for using mark-to-market accounting, with a small number accounted for as cash flow hedges. We did not have any cash flow hedges related to our natural gas marketing activities at December 31, 2008.

The following table shows the effect of hypothetical price movements on the estimated fair value of this component of the overall portfolio at the dates presented (dollars in millions):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2007**	**December 31, 2008**	**February 3, 2009**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (0.3)	$ 6.5	$ 13.9
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(1.4)	2.7	9.4
FV assuming 10% decrease in underlying commodity prices	*Asset*	0.7	9.9	18.3

The change in fair value of the instruments between December 31, 2008 and February 3, 2009 is primarily due to a decrease in natural gas prices.

Crude oil marketing activities

The fair value of the open positions at December 31, 2008 and 2007 was an asset of $3 thousand and a liability of $18.9 million, respectively. At December 31, 2008, we had no commodity derivative instruments that were accounted for as cash flow hedges. At December 31, 2007, we had a limited number of commodity derivative instruments that were accounted for as cash flow hedges. We have some commodity derivative instruments that do not qualify for hedge accounting. These derivative instruments had a minimal impact on our earnings.

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

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2007**	**December 31, 2008** (1)	**February 3, 2009**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (18.9)	$ --	$ 0.2
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(33.6)	--	0.2
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(4.2)	--	0.2

(1) Amounts were minimal at December 31, 2008.

NGL and petrochemical operations

At December 31, 2008 and 2007, the aggregate fair value of those derivative instruments utilized in connection with our NGL and petrochemical operations were liabilities of $102.1 million and $19.0 million, respectively. Almost all of the derivative instruments within this portion of the commodity derivative instruments portfolio are accounted for as cash flow hedges, with a small number accounted for using mark-to-market accounting. We expect to reclassify $114.0 million of cumulative net losses from these cash flow hedges into net income (as an increase in operating costs and expenses) during 2009.

We have employed a program to economically hedge a portion of our earnings from natural gas processing in the Rocky Mountain region. This program consists of (i) the forward sale of a portion of our expected equity NGL production volumes at fixed prices through 2009 and (ii) the purchase, using commodity derivative instruments, of the amount of natural gas expected to be consumed as plant thermal reduction ("PTR") in the production of such equity NGL volumes. The objective of this strategy is to hedge a level of gross margins (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) associated with the forward sales contracts by fixing the cost of natural gas used for PTR, through the use of commodity derivative instruments. At December 31, 2008, this hedging program had hedged future expected gross margins (before plant operating expenses) of $483.9 million on 22.5 million barrels of forecasted NGL forward sales transactions extending through 2009.

Our NGL forward sales contracts are not accounted for as derivative instruments under SFAS 133 since they meet normal purchase and sale exception criteria; therefore, changes in the aggregate economic value of these sales contracts are not reflected in net income and other comprehensive income until the volumes are delivered to customers. On the other hand, the commodity derivative instruments used to purchase the related quantities of PTR (i.e., "PTR hedges") are accounted for as cash flow hedges; therefore, changes in the aggregate fair value of the PTR hedges are presented in other comprehensive income. Once the forecasted NGL forward sales transactions occur, any realized gains and losses on the cash flow hedges would be reclassified into net income in that period.

Prior to actual settlement, if the market price of natural gas is less than the price stipulated in a commodity derivative instrument, we recognize an unrealized loss in other comprehensive loss for the excess of the natural gas price stated in the hedge over the market price. To the extent that we realize such financial losses upon settlement of the instrument, the losses are added to the actual cost we pay for PTR, which would then be based on the lower market price. Conversely, if the market price of natural gas is greater than the price stipulated in such hedges, we recognize an unrealized gain in other comprehensive income for the excess of the market price over the natural gas price stated in the PTR hedge. If realized, the gains on the derivative instrument would serve to reduce the actual cost paid for PTR, which would then be based on the higher market price. The net effect of these hedging relationships is that our total cost of natural gas used for PTR approximates the amount it originally hedged under this program.

The following table shows the effect of hypothetical price movements on the estimated fair value of this component of the overall portfolio at the dates presented (dollars in millions):

		Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2007	December 31, 2008	February 3, 2009
FV assuming no change in underlying commodity prices	*Liability*	$ (19.0)	$ (102.1)	$ (111.6)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	11.3	(94.0)	(109.2)
FV assuming 10% decrease in underlying commodity prices	*Liability*	(49.2)	(110.1)	(114.1)

The change in fair value of the NGL and petrochemical portfolio between December 31, 2008 and February 3, 2009 is primarily due to a decrease in natural gas prices.

Foreign Currency Hedging Portfolio

We are exposed to foreign currency exchange rate risk primarily through a Canadian NGL marketing subsidiary. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate. Mark-to-market accounting is utilized for these contracts, which typically have a duration of one month. For the year ended December 31, 2008, we recorded minimal gains from these derivative instruments.

In addition, we are exposed to foreign currency exchange rate risk through our Japanese Yen Term Loan Agreement ("Yen Term Loan") that EPO entered into in November 2008. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Japanese yen. We hedged this risk by entering into a foreign exchange purchase contract to fix the exchange rate. This purchase contract was designated as a cash flow hedge. At December 31, 2008, the fair value of this contract was $9.3 million. This contract will be settled in March 2009 upon repayment of the Yen Term Loan. Total interest expense under this loan agreement was $4.0 million, of which $1.7 million is the expected foreign currency loss, which will be recorded as interest expense.

Product Purchase Commitments

We have long and short-term purchase commitments for natural gas, NGLs, crude oil, refined products and petrochemicals with several suppliers. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, see "Contractual Obligations" included under Item 7 within this Exhibit 99.1.

Fair Value Information

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. See Note 8 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for information regarding fair value disclosures pertaining to our financial assets and liabilities.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily includes the effective portion of the gain or loss on derivative instruments designated and qualified as a cash flow hedge, foreign currency adjustments and Dixie's minimum pension liability adjustments. Amounts accumulated in other comprehensive income (loss) from cash flow hedges are reclassified into earnings in the same period(s) in which the hedged forecasted transactions (such as a forecasted forward sale of NGLs) affect earnings. If it becomes probable that the forecasted transaction will not occur, the net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified.

The following table presents the components of accumulated other comprehensive income (loss) at the dates indicated (dollars in millions):

	December 31,	
	2008	2007
Commodity derivative instruments (1)	$ (114.1)	$ (40.3)
Interest rate derivative instruments (1)	(41.9)	11.1
Foreign currency cash flow hedges (1)	10.6	1.3
Foreign currency translation adjustment (2)	(1.3)	1.2
Pension and postretirement benefit plans (3)	(0.8)	0.6
Subtotal	(147.5)	(26.1)
Amount attributable to noncontrolling interest (4)	50.3	45.2
Total accumulated other comprehensive income (loss) in partners' equity	$ (97.2)	$ 19.1

(1) See Note 7 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for additional information regarding these components of accumulated other comprehensive income (loss).
(2) Relates to transactions of our Canadian NGL marketing subsidiary.
(3) See Note 6 of the Notes to Supplemental Consolidated Financial Statements included under Exhibit 99.2 of this Current Report on Form 8-K for additional information regarding pension and postretirement benefit plans.
(4) Represents the amount of accumulated other comprehensive loss allocated to noncontrolling interest based on the provisions of SFAS 160.

The following table summarizes the components of other comprehensive income (loss) for the periods indicated, prior to attributing amounts to noncontrolling interest (dollars in millions):

	For Year Ended December 31,		
	2008	2007	2006
Other comprehensive income (loss):			
Cash flow hedges	$ (117.7)	$ (50.8)	$ 3.9
Change in funded status of pension and postretirement plans, net of tax	(1.3)	--	--
Foreign currency translation adjustment	(2.5)	2.0	(0.8)
Total other comprehensive income (loss)	$ (121.5)	$ (48.8)	$ 3.1

ENTERPRISE PRODUCTS PARTNERS L.P.
RECAST OF ITEM 8 FROM CURRENT REPORT ON FORM 8-K DATED JULY 8, 2009

Recast of Item 8. ***Financial Statements and Supplementary Data.***

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the accompanying supplemental consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related supplemental statements of consolidated operations, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2008. These supplemental financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the supplemental 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, such supplemental consolidated financial statements present fairly, in all material respects, the financial position of Enterprise Products Partners L.P. and subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

The supplemental consolidated financial statements give retroactive effect to the acquisition of TEPPCO Partners, L.P. (“TEPPCO”) and Texas Eastern Products Pipeline Company, LLC (“TEPPCO GP”) by the Company on October 26, 2009, which has been accounted for at historical cost as a reorganization of entities under common control as described in Note 1 to the supplemental consolidated financial statements. Also as discussed in Note 1 to the supplemental consolidated financial statements, the disclosures in the accompanying supplemental consolidated financial statements have been retrospectively adjusted for a change in the composition of reportable segments as a result of the acquisition of TEPPCO and TEPPCO GP by the Company.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
December 4, 2009

ENTERPRISE PRODUCTS PARTNERS L.P.
SUPPLEMENTAL CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 61.7	$ 51.3
Restricted cash	203.8	53.1
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $17.7 at December 31, 2008 and $21.8 at December 31, 2007	2,028.5	3,363.4
Accounts receivable – related parties	35.3	40.1
Inventories	405.0	425.7
Derivative assets	218.6	12.3
Prepaid and other current assets	149.8	115.1
Total current assets	3,102.7	4,061.0
Property, plant and equipment, net	16,732.8	14,309.1
Investments in unconsolidated affiliates	911.9	885.6
Intangible assets, net of accumulated amortization of $675.1 at December 31, 2008 and $545.9 at December 31, 2007	1,182.9	1,214.1
Goodwill	2,019.6	1,813.3
Deferred tax asset	0.4	3.5
Other assets	261.3	228.9
Total assets	$ 24,211.6	$ 22,515.5
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ --	$ 354.0
Accounts payable – trade	388.9	398.3
Accounts payable – related parties	17.4	16.7
Accrued product payables	1,845.7	3,572.8
Accrued interest payable	188.3	166.5
Other accrued expenses	65.7	62.0
Derivative liabilities	302.9	96.4
Other current liabilities	292.3	292.6
Total current liabilities	3,101.2	4,959.3
Long-term debt: (see Note 14)		
Senior debt obligations – principal	10,030.1	6,837.5
Junior subordinated notes – principal	1,532.7	1,550.0
Other	75.1	29.6
Total long-term debt	11,637.9	8,417.1
Deferred tax liabilities	66.1	21.4
Other long-term liabilities	110.5	101.2
Commitments and contingencies		
Equity: (see Note 15)		
Enterprise Products Partners L.P. partners' equity:		
Limited Partners:		
Common units (439,354,731 units outstanding at December 31, 2008 and 433,608,763 units outstanding at December 31, 2007)	6,036.9	5,977.0
Restricted common units (2,080,600 units outstanding at December 31, 2008 and 1,688,540 units outstanding at December 31, 2007)	26.2	15.9
General partner	123.6	122.3
Accumulated other comprehensive income (loss)	(97.2)	19.1
Total Enterprise Products Partners L.P. partners' equity	6,089.5	6,134.3
Noncontrolling interest	3,206.4	2,882.2
Total equity	9,295.9	9,016.5
Total liabilities and equity	$ 24,211.6	$ 22,515.5

See Notes to Supplemental Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
SUPPLEMENTAL STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in millions, except per unit amounts)

	For Year Ended December 31,		
	2008	**2007**	**2006**
Revenues:			
Third parties	$ 34,454.2	$ 26,128.6	$ 23,251.4
Related parties	1,015.4	585.2	360.7
Total revenues (see Note 16)	35,469.6	26,713.8	23,612.1
Costs and expenses:			
Operating costs and expenses:			
Third parties	32,861.9	24,938.2	21,976.5
Related parties	757.0	463.9	443.8
Total operating costs and expenses	33,618.9	25,402.1	22,420.3
General and administrative costs:			
Third parties	43.4	44.6	32.2
Related parties	93.8	82.6	63.7
Total general and administrative costs	137.2	127.2	95.9
Total costs and expenses	33,756.1	25,529.3	22,516.2
Equity in income of unconsolidated affiliates	34.9	10.5	25.2
Operating income	1,748.4	1,195.0	1,121.1
Other income (expense):			
Interest expense	(540.7)	(413.0)	(324.2)
Interest income	7.4	11.1	9.7
Other, net	4.8	60.6	1.5
Total other expense, net	(528.5)	(341.3)	(313.0)
Income before provision for income taxes and the cumulative effect of change in accounting principle	1,219.9	853.7	808.1
Provision for income taxes	(31.0)	(15.7)	(22.0)
Income before the cumulative effect of change in accounting principle	1,188.9	838.0	786.1
Cumulative effect of change in accounting principle (see Note 8)	--	--	1.5
Net income	1,188.9	838.0	787.6
Net income attributable to noncontrolling interest (see Note 15)	(234.9)	(304.4)	(186.5)
Net income attributable to Enterprise Products Partners L.P.	$ 954.0	$ 533.6	$ 601.1
Net income allocated to: (see Note 15)			
Limited partners	$ 811.5	$ 417.7	$ 504.1
General partner	$ 142.5	$ 115.9	$ 97.0
Earnings per unit: (see Note 19)			
Basic and diluted earnings per unit before change in accounting principle	$ 1.84	$ 0.95	$ 1.20
Basic and diluted earnings per unit	$ 1.84	$ 0.95	$ 1.20

See Notes to Supplemental Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
SUPPLEMENTAL STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in millions)

	For Year Ended December 31,		
	2008	2007	2006
Net income	$ 1,188.9	$ 838.0	$ 787.6
Other comprehensive income (loss):			
Cash flow hedges:			
Commodity derivative instrument gains (losses) during period	(170.2)	(46.9)	9.9
Reclassification adjustment for (gains) losses included in net income related to commodity derivative instruments	96.3	9.5	(12.8)
Interest rate derivative instrument gains (losses) during period	(55.6)	(8.9)	11.0
Reclassification adjustment for (gains) losses included in net income related to interest rate derivative instruments	2.5	(5.8)	(4.2)
Foreign currency hedge gains	9.3	1.3	--
Total cash flow hedges	(117.7)	(50.8)	3.9
Foreign currency translation adjustment	(2.5)	2.0	(0.8)
Change in funded status of pension and postretirement plans, net of tax	(1.3)	--	--
Total other comprehensive income (loss)	(121.5)	(48.8)	3.1
Comprehensive income	1,067.4	789.2	790.7
Comprehensive income attributable to noncontrolling interest	(229.6)	(258.7)	(187.0)
Comprehensive income attributable to Enterprise Products Partners L.P.	$ 837.8	$ 530.5	$ 603.7

See Notes to Supplemental Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
SUPPLEMENTAL STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)

	For Year Ended December 31,		
	2008	**2007**	**2006**
Operating activities:			
Net income	$ 1,188.9	$ 838.0	$ 787.6
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	737.8	658.4	563.5
Equity in income of unconsolidated affiliates	(34.9)	(10.5)	(25.2)
Distributions received from unconsolidated affiliates	80.8	87.0	76.5
Cumulative effect of change in accounting principle	--	--	(1.5)
Operating lease expense paid by EPCO, Inc.	2.0	2.1	2.1
Gain from asset sales and related transactions	(4.0)	(67.4)	(5.1)
Loss on early extinguishment of debt	1.6	1.6	--
Deferred income tax expense	6.2	7.6	15.1
Changes in fair market value of derivative instruments	(0.1)	1.3	(0.1)
Effect of pension settlement recognition	(0.1)	0.6	--
Net effect of changes in operating accounts (see Note 22)	(411.1)	434.9	46.2
Net cash flows provided by operating activities	1,567.1	1,953.6	1,459.1
Investing activities:			
Capital expenditures	(2,541.0)	(2,764.0)	(1,727.7)
Contributions in aid of construction costs	28.6	57.6	60.5
Increase in restricted cash	(132.8)	(47.3)	(8.7)
Cash used for business combinations (see Note 12)	(553.4)	(35.9)	(292.2)
Acquisition of intangible assets	(5.8)	(14.5)	--
Investments in unconsolidated affiliates	(64.7)	(236.8)	(11.3)
Proceeds from asset sales and related transactions	22.2	169.1	5.8
Cash used in investing activities	(3,246.9)	(2,871.8)	(1,973.6)
Financing activities:			
Borrowings under debt agreements	13,188.0	7,629.8	4,302.1
Repayments of debt	(10,434.3)	(5,799.9)	(3,747.0)
Debt issuance costs	(27.5)	(20.6)	(8.9)
Cash distributions paid to partners	(1,037.5)	(957.7)	(843.3)
Cash distributions paid to noncontrolling interest	(383.9)	(326.8)	(287.4)
Net cash proceeds from issuance of common units	142.8	69.2	857.2
Cash contributions from noncontrolling interest	311.5	304.7	222.6
Repurchase of restricted units and option awards	--	(1.5)	--
Acquisition of treasury units	(1.9)	--	--
Monetization of interest rate derivative instruments (see Note 7)	(66.5)	49.1	--
Cash provided by financing activities	1,690.7	946.3	495.3
Effect of exchange rate changes on cash	(0.5)	0.4	(0.2)
Net change in cash and cash equivalents	10.9	28.1	(19.2)
Cash and cash equivalents, January 1	51.3	22.8	42.2
Cash and cash equivalents, December 31	$ 61.7	$ 51.3	$ 22.8

See Notes to Supplemental Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
SUPPLEMENTAL STATEMENTS OF CONSOLIDATED EQUITY
(See Note 15 for Unit History, Detail of Changes in Limited Partners' Equity and Accumulated Other Comprehensive Income (Loss))
(Dollars in millions)

	Enterprise Products Partners L.P.					
	Limited Partners	General Partner	Deferred Compensation	Accum. Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2005	$ 5,561.3	$ 113.5	$ (14.6)	$ 19.1	$ 2,524.5	$ 8,203.8
Net income	504.1	97.0	--	--	186.5	787.6
Operating leases paid by EPCO, Inc.	2.1	--	--	--	--	2.1
Cash distributions paid to partners	(739.6)	(101.8)	--	--	--	(841.4)
Unit option reimbursements to EPCO, Inc.	(1.9)	--	--	--	--	(1.9)
Cash distributions paid to noncontrolling interest	--	--	--	--	(287.4)	(287.4)
Net cash proceeds from issuance of common units	830.8	17.0	--	--	--	847.8
Common units issued to Lewis in connection with Encinal acquisition	181.1	3.7	--	--	--	184.8
Cash proceeds from exercise of unit options	5.6	0.1	--	--	--	5.7
Cash contributions from noncontrolling interest	--	--	--	--	222.6	222.6
Change in accounting method for equity awards	(15.8)	(0.3)	14.6	--	--	(1.5)
Amortization of equity awards	8.3	0.2	--	--	--	8.5
Interest acquired from noncontrolling interest	--	--	--	--	(2.0)	(2.0)
Foreign currency translation adjustment	--	--	--	(0.8)	--	(0.8)
Change in funded status of pension and postretirement plans	--	--	--	(0.6)	--	(0.6)
Acquisition-related disbursement of cash	(6.2)	(0.1)	--	--	--	(6.3)
Cash flow hedges	--	--	--	3.4	0.5	3.9
Balance, December 31, 2006	6,329.8	129.3	--	21.1	2,644.7	9,124.9
Net income	417.7	115.9	--	--	304.4	838.0
Operating leases paid by EPCO, Inc.	2.1	--	--	--	--	2.1
Cash distributions paid to partners	(833.8)	(124.4)	--	--	--	(958.2)
Unit option reimbursements to EPCO, Inc.	(3.0)	--	--	--	--	(3.0)
Cash distributions paid to noncontrolling interest	--	--	--	--	(326.8)	(326.8)
Net cash proceeds from issuance of common units	60.4	1.2	--	--	--	61.6
Cash proceeds from exercise of unit options	7.5	0.1	--	--	--	7.6
Cash contributions from noncontrolling interest	--	--	--	--	304.7	304.7
Repurchase of restricted units and options	(1.5)	--	--	--	--	(1.5)
Amortization of equity awards	13.7	0.2	--	--	0.8	14.7
Foreign currency translation adjustment	--	--	--	2.0	--	2.0
Change in funded status of pension and postretirement plans	--	--	--	1.2	--	1.2
Cash flow hedges	--	--	--	(5.2)	(45.6)	(50.8)
Balance, December 31, 2007	5,992.9	122.3	--	19.1	2,882.2	9,016.5
Net income	811.5	142.5	--	--	234.9	1,188.9
Operating leases paid by EPCO, Inc.	2.0	--	--	--	--	2.0
Cash distributions paid to partners	(892.7)	(144.1)	--	--	--	(1,036.8)
Unit option reimbursements to EPCO, Inc.	(0.6)	--	--	--	--	(0.6)
Cash distributions paid to noncontrolling interest	--	--	--	--	(383.9)	(383.9)
Net cash proceeds from issuance of common units	139.3	2.8	--	--	--	142.1
Issuance of units by TEPPCO in connection with Cenac acquisition (see Note 12)	--	--	--	--	186.6	186.6
Cash proceeds from exercise of unit options	0.7	--	--	--	--	0.7
Cash contributions from noncontrolling interest	--	--	--	--	311.5	311.5
Amortization of equity awards	11.9	0.1	--	--	2.1	14.1
Interest acquired from noncontrolling interest	--	--	--	--	(22.3)	(22.3)
Acquisition of treasury units	(1.9)	--	--	--	--	(1.9)
Foreign currency translation adjustment	--	--	--	(2.5)	--	(2.5)
Change in funded status of pension and postretirement plans	--	--	--	(1.3)	--	(1.3)
Cash flow hedges	--	--	--	(112.5)	(5.2)	(117.7)
Other	--	--	--	--	0.5	0.5
Balance, December 31, 2008	$ 6,063.1	$ 123.6	$ --	$ (97.2)	$ 3,206.4	$ 9,295.9

See Notes to Supplemental Consolidated Financial Statements.

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

Note 1. Partnership Organization and Basis of Presentation

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our" or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries, which now includes TEPPCO Partners, L.P. and its general partner.

We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO, Inc. ("EPCO"). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating LLC ("EPO"). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as "EPGP"). EPGP is owned 100% by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded limited partnership, the units of which are listed on the NYSE under the ticker symbol "EPE." The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), a wholly owned subsidiary of Dan Duncan LLC, all of the membership interests of which are owned by Dan L. Duncan. We, EPGP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates and under common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries. On October 26, 2009, we completed the mergers with TEPPCO and TEPPCO GP (such related mergers referred to herein individually and together as the "TEPPCO Merger"). See "TEPPCO Merger and Basis of Presentation" within this Note 1 for additional information regarding the TEPPCO Merger.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries. References to "LE GP" mean LE GP, LLC, which is the general partner of Energy Transfer Equity. On May 7, 2007, Enterprise GP Holdings acquired noncontrolling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II"), EPE Unit III, L.P. ("EPE Unit III"), Enterprise Unit L.P. ("Enterprise Unit"), EPCO Unit L.P. ("EPCO Unit"), TEPPCO Unit L.P. ("TEPPCO Unit I"), and TEPPCO Unit II L.P. ("TEPPCO Unit II"), collectively, all of which are private company affiliates of EPCO.

On February 5, 2007, a consolidated subsidiary of ours, Duncan Energy Partners L.P. ("Duncan Energy Partners"), completed an initial public offering of its common units (see Note 17). Duncan Energy Partners owns equity interests in certain of our midstream energy businesses. References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

On December 8, 2008, Duncan Energy Partners entered into a Purchase and Sale Agreement (the "DEP II Purchase Agreement") with EPO and Enterprise GTM Holdings L.P. ("Enterprise GTM," a wholly owned subsidiary of EPO). Pursuant to the DEP II Purchase Agreement, DEP Operating Partnership L.P. ("DEP OLP") acquired 100% of the membership interests in Enterprise III, LLC ("Enterprise III") from Enterprise GTM, thereby acquiring a 66% general partner interest in Enterprise GC, L.P. ("Enterprise GC"), a 51% general partner interest in Enterprise Intrastate L.P. ("Enterprise Intrastate") and a 51% membership interest in Enterprise Texas Pipeline LLC ("Enterprise Texas"). Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the "DEP II Midstream Businesses." EPO was the sponsor of this second dropdown transaction. Enterprise GTM retained the remaining general partner and member interests in the DEP II Midstream Businesses (see Note 17).

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. We control Duncan Energy Partners through our ownership of its general partner. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of noncontrolling interest in our supplemental consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, neither Enterprise Products Partners L.P. nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

TEPPCO Merger and Basis of Presentation

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 of our common units for each TEPPCO unit. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. TEPPCO's units, which had been trading on the NYSE under the ticker symbol TPP, have been delisted and are no longer publicly traded.

A privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

Under the terms of the TEPPCO Merger agreements, Enterprise GP Holdings received 1,331,681 of our common units and an increase in the capital account of EPGP to maintain its 2% general partner interest in us as consideration for 100% of the membership interests of TEPPCO GP. Following the closing of the TEPPCO Merger, affiliates of EPCO owned approximately 31.3% of our outstanding limited partner units, including 3.4% owned by Enterprise GP Holdings.

Since Enterprise Products Partners, TEPPCO and TEPPCO GP are under common control of Mr. Duncan, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. The inclusion of TEPPCO and TEPPCO GP in our supplemental consolidated financial statements was effective January 1, 2005 since an affiliate of EPCO under common control with Enterprise Products Partners originally acquired ownership interests in TEPPCO GP in February 2005.

Our supplemental consolidated financial statements prior to the effective date of the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third party and related party ownership interests in TEPPCO and TEPPCO GP prior to the merger have been reflected as "Former owners of TEPPCO" a component of noncontrolling interest.

Our supplemental financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). The financial statements of TEPPCO and TEPPCO GP were prepared from the separate accounting records maintained by TEPPCO and TEPPCO GP. All intercompany balances and transactions have been eliminated in the preparation of our consolidated financial statements.

We revised our business segments and related disclosures to reflect the TEPPCO Merger. Our reorganized business segments reflect the manner in which these businesses are managed and reviewed by the chief executive officer of our general partner. Under our new business segment structure, we have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services.

As previously noted, the TEPPCO Merger was accounted for as a reorganization of entities under common control. The following information is provided to reconcile total revenues and total gross operating margin for the years ended December 31, 2008, 2007 and 2006, as currently presented, with those we previously presented. There was no change in net income attributable to Enterprise Products Partners L.P. for such periods since net income attributable to TEPPCO and TEPPCO GP was allocated to noncontrolling interests. Additionally, there was no change in our reported earnings per unit for such periods. See Note 16 for information regarding total segment gross operating margin, which is a non-generally accepted accounting principle ("non-GAAP") financial measure of segment performance.

	For Year Ended December 31,		
	2008	**2007**	**2006**
Total revenues, as previously reported	$ 21,905.6	$ 16,950.1	$ 13,990.9
Revenues from TEPPCO	13,532.9	9,658.1	9,612.2
Revenues from Jonah Gas Gathering Company ("Jonah") (1)	232.8	204.1	78.5
Eliminations (2)	(201.7)	(98.5)	(69.5)
Total revenues, as currently reported	$ 35,469.6	$ 26,713.8	$ 23,612.1
Total segment gross operating margin, as previously reported	$ 2,057.4	$ 1,492.1	$ 1,362.4
Gross operating margin from TEPPCO	501.0	434.8	398.1
Gross operating margin from Jonah	157.6	125.4	43.5
Eliminations (3)	(107.0)	(87.9)	(33.1)
Total segment gross operating margin, as currently reported	$ 2,609.0	$ 1,964.4	$ 1,770.9

(1) Prior to the TEPPCO Merger, we and TEPPCO were joint venture partners in Jonah. As a result of the TEPPCO Merger, Jonah became a consolidated subsidiary.
(2) Represents the eliminations of revenues between us, TEPPCO and Jonah.
(3) Represents equity earnings from Jonah recorded by us and TEPPCO prior to the merger.

Note 2. General Accounting Matters

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. Our procedure for determining the allowance for doubtful accounts is based on (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses. Our allowance also includes estimates for uncollectible natural gas imbalances based on specific identification of accounts.

The following table presents the activity of our allowance for doubtful accounts for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
Balance at beginning of period	$ 21.8	$ 23.5	$ 37.6
Charges to expense	3.5	2.6	0.5
Deductions	(7.6)	(4.3)	(14.6)
Balance at end of period	$ 17.7	$ 21.8	$ 23.5

See “Credit Risk Due to Industry Concentrations” in Note 21 for more information.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase.

Our Supplemental Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows provided by operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) other non-cash amounts such as depreciation, amortization, changes in the fair market value of derivative instruments and equity in earnings in unconsolidated affiliates and (iv) the effects of all items classified as investing or financing cash flows, such as proceeds from asset sales and related transactions or extinguishment of debt.

Consolidation Policy

Our supplemental consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all material intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership. We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own.

If the entity is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50% and we exercise significant influence over the entity’s operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the entity’s operating and financial policies. In consolidation we eliminate our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates to the extent such amounts are material and remain on our Supplemental Consolidated Balance Sheets (or those of our equity method investments) in inventory or similar accounts.

If our ownership interest in an entity does not provide us with either control or significant influence we account for the investment using the cost method. We currently do not have any investments accounted for using the cost method.

Contingencies

Certain conditions may exist as of the date our supplemental 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 management and legal counsel evaluate 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 supplemental 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.

Current Assets and Current Liabilities

We present, as individual captions in our Supplemental Consolidated Balance Sheets, all components of current assets and current liabilities that exceed 5% of total current assets and liabilities, respectively.

Deferred Revenues

Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. At December 31, 2008 and 2007, deferred revenues totaled $118.5 million and $87.4 million, respectively, and were recorded as a component of other current and long-term liabilities, as appropriate, on our Supplemental Consolidated Balance Sheets. See Note 4 for information regarding our revenue recognition policies.

Earnings Per Unit

Earnings per unit is based on the amount of income allocated to limited partners and the weighted-average number of units outstanding during the period. See Note 19 for additional information regarding our earnings per unit.

Employee Benefit Plans

SFAS 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of SFAS 87, 88, 106, and 132(R), requires businesses to record the over-funded or under-funded status of defined benefit pension and other postretirement plans as an asset or liability at a measurement date and to recognize annual changes in the funded status of each plan through other comprehensive income (loss).

Our consolidated results reflect immaterial amounts related to active and terminated benefit plans. See Note 6 for additional information regarding our current employee benefit plans.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2008, none of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable.

Environmental costs and related accruals were not significant prior to the GulfTerra Merger. As a result of the merger, we assumed an environmental liability for remediation costs associated with mercury gas meters. The balance of this environmental liability was $6.3 million and $17.2 million at December 31, 2008 and 2007, respectively. At December 31, 2008 and 2007, total reserves for environmental liabilities, including those related to the mercury gas meters, were $22.3 million and $30.5 million, respectively. At December 31, 2008 and 2007, $5.3 million and $7.9 million, respectively, of these amounts are classified as current liabilities.

In February 2007, we reserved $6.5 million in cash we received from a third party to fund anticipated environmental remediation costs. These expected costs are associated with assets acquired in connection with the GulfTerra Merger. Previously, the third party had been obligated to indemnify us for such costs. As a result of the settlement, this indemnification arrangement was terminated.

The following table presents the activity of our environmental reserves for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
Balance at beginning of period	$ 30.5	$ 26.0	$ 24.5
Charges to expense	5.9	3.8	3.0
Acquisition-related additions and other	--	6.5	8.8
Deductions	(14.1)	(5.8)	(10.3)
Balance at end of period	$ 22.3	$ 30.5	$ 26.0

Equity Awards

See Note 5 for information regarding our accounting for equity awards.

Estimates

Preparing our supplemental financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the supplemental financial statements (i.e. assets, liabilities, revenue and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

We revised the remaining useful lives of certain assets, most notably the assets that constitute our Texas Intrastate System, effective January 1, 2008. This revision adjusted the remaining useful life of such assets to incorporate recent data showing that proved natural gas reserves supporting throughput and processing volumes for these assets have changed since our original determination made in September 2004. These revisions will prospectively reduce our depreciation expense on assets having carrying values totaling $2.72 billion at January 1, 2008. For additional information regarding this change in estimate, see Note 10.

Exchange Contracts

Exchanges are contractual agreements for the movements of NGLs and certain petrochemical products between parties to satisfy timing and logistical needs of the parties. Net exchange volumes borrowed from us under such agreements are valued at market-based prices and included in accounts receivable, and net exchange volumes loaned to us under such agreements are valued at market-based prices and accrued as a liability in accrued product payables.

Receivables and payables arising from exchange transactions are settled with movements of products rather than with cash. When payment or receipt of monetary consideration is required for product differentials and service costs, such items are recognized in our supplemental consolidated financial statements on a net basis.

Exit and Disposal Costs

Exit and disposal costs are charges associated with an exit activity not associated with a business combination or with a disposal activity covered by SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets. Examples of these costs include (i) termination benefits provided to current employees that are involuntarily terminated under the terms of a benefit arrangement that, in substance, is not an ongoing benefit arrangement or an individual deferred compensation contract, (ii) costs to terminate a contract that is not a capital lease, and (iii) costs to consolidate facilities or relocate employees. In accordance with SFAS 146, Accounting for Costs Associated with Exit and Disposal Activities, we recognize such costs when they are incurred rather than at the date of our commitment to an exit or disposal plan.

Derivative Instruments

We use derivative instruments such as swaps, forwards and other contracts to manage price risks associated with inventories, firm commitments, interest rates, foreign currency and certain anticipated transactions. We recognize these transactions as assets or liabilities on our Supplemental Consolidated Balance Sheets based on the instrument's fair value. Fair value is generally defined as the amount at which a derivative instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale.

Changes in fair value of derivative instrument contracts are recognized in earnings in the current period (i.e., using mark-to-market accounting) unless specific hedge accounting criteria are met. If the derivative instrument meets the criteria of a fair value hedge, gains and losses incurred on the instrument will be recorded in earnings to offset corresponding losses and gains on the hedged item. If the derivative instrument meets the criteria of a cash flow hedge, gains and losses incurred on the instrument are recorded in accumulated other comprehensive income (loss), which is generally referred to as "AOCI." Gains and losses on cash flow hedges are reclassified from accumulated other comprehensive income (loss) to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the hedged item. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify for hedge accounting, the item to be hedged must expose us to risk and the related hedging instrument must reduce the exposure and meet the hedging requirements of SFAS 133, Accounting for Derivative Instruments and Hedging Activities (as amended and interpreted). We formally designate the derivative instrument as a hedge and document and assess the effectiveness of the hedge at its inception and thereafter on a quarterly basis. Any hedge ineffectiveness is immediately recognized in earnings. See Note 7 for additional information regarding our derivative instruments.

Foreign Currency Translation

We own a NGL marketing business located in Canada. The financial statements of this foreign subsidiary are translated into U.S. dollars from the Canadian dollar, which is the subsidiary's functional currency, using the current rate method. Its assets and liabilities are translated at the rate of exchange in effect at the balance sheet date, while revenue and expense items are translated at average rates of exchange during the reporting period. Exchange gains and losses arising from foreign currency translation adjustments are reflected as separate components of accumulated other comprehensive income (loss) in the accompanying Supplemental Consolidated Balance Sheets. Our net cash flows from this Canadian subsidiary may be adversely affected by changes in foreign currency exchange rates. See Note 7 for information regarding our hedging of currency risk.

Impairment Testing for Goodwill

Our goodwill amounts are assessed for impairment (i) on a routine annual basis or (ii) when impairment indicators are present. If such indicators occur (e.g., the loss of a significant customer, economic obsolescence of plant assets, etc.), the estimated fair value of the reporting unit to which the goodwill is assigned is determined and compared to its book value. If the fair value of the reporting unit exceeds its book value including associated goodwill amounts, the goodwill is considered to be unimpaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value including associated goodwill amounts, a charge to earnings is recorded to reduce the carrying value of the goodwill to its implied fair value. We have not recognized any impairment losses related to goodwill for any of the periods presented. See Note 13 for additional information regarding our goodwill.

Impairment Testing for Long-Lived Assets

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable.

Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values in accordance with SFAS 144. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset's carrying value over its estimated fair value is recorded. Fair value is defined as the amount at which an asset or liability could be bought or settled in an arm's-length transaction. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques.

We recorded a non-cash asset impairment charge of $0.1 million in 2006, which is reflected as a component of operating costs and expenses in our 2006 Supplemental Statement of Consolidated Operations. No asset impairment charges were recorded in 2008 and 2007.

Impairment Testing for Unconsolidated Affiliates

We evaluate our equity method investments for impairment when events or changes in circumstances indicate that there is a loss in value of the investment attributable to an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's industry. In the event we determine that the loss in value of an investment is other than a temporary decline, we record a charge to earnings to adjust the carrying value of the investment to its estimated fair value.

During 2007, we evaluated our equity method investment in Nemo Gathering Company, LLC ("Nemo") for impairment. As a result of this evaluation, we recorded a $7.0 million non-cash impairment charge that is a component of "Equity in earnings of unconsolidated affiliates" on our Supplemental Consolidated Statement of Operations for the year ended December 31, 2007. Similarly, during 2006, we evaluated our investment in Neptune Pipeline Company, L.L.C. ("Neptune") for impairment. As a result of this evaluation, we recorded a $7.4 million non-cash impairment charge that is a component of "Equity in earnings of unconsolidated affiliates" on our Supplemental Consolidated Statement of Operations for the year ended December 31, 2006. We had no such impairment charges during the year ended December 31, 2008. See Note 11 for additional information regarding our equity method investments.

Income Taxes

Provision for income taxes is primarily applicable to our state tax obligations under the Revised Texas Franchise Tax and certain federal and state tax obligations of Seminole Pipeline Company ("Seminole") and Dixie Pipeline Company ("Dixie"), both of which are consolidated subsidiaries of ours.

Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

In general, legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax. In May 2006, the State of Texas expanded its pre-existing franchise tax, which applied to corporations and limited liability companies, to include limited partnerships and limited liability partnerships. As a result of the change in tax law, our tax status in the State of Texas changed from non-taxable to taxable.

Since we are structured as a pass-through entity, we are not subject to federal income taxes. As a result, our partners are individually responsible for paying federal income taxes on their share of our taxable income. Since we do not have access to information regarding each partner's tax basis, we cannot readily determine the total difference in the basis of our net assets for financial and tax reporting purposes.

In accordance with Financial Accounting Standards Board Interpretation 48, Accounting for Uncertainty in Income Taxes, we must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable. If a tax position meets such criteria, the tax effect to be recognized by us would be the largest amount of benefit with more than a 50% chance of being realized upon settlement. This guidance was effective January 1, 2007, and our adoption of this guidance had no material impact on our financial position, results of operations or cash flows. See Note 18 for additional information regarding our income taxes.

Inventories

Inventories primarily consist of NGLs, petroleum products, certain petrochemical products and natural gas volumes that are valued at the lower of average cost or market. We capitalize, as a cost of inventory, shipping and handling charges directly related to volumes we purchase from third parties or take title to in connection with processing or other agreements. As these volumes are sold and delivered out of inventory, the average cost of these products (including freight-in charges that have been capitalized) are charged to operating costs and expenses. Shipping and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. See Note 9 for additional information regarding our inventories.

Natural Gas Imbalances

In the natural gas pipeline transportation business, imbalances frequently result from differences in natural gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. We have various fee-based agreements with customers to transport their natural gas through our pipelines. Our customers retain ownership of their natural gas shipped through our pipelines. As such, our pipeline transportation activities are not intended to create physical volume differences that would result in significant accounting or economic events for either our customers or us during the course of the arrangement.

We settle pipeline gas imbalances through either (i) physical delivery of in-kind gas or (ii) in cash. These settlements follow contractual guidelines or common industry practices. As imbalances occur, they may be settled (i) on a monthly basis, (ii) at the end of the agreement or (iii) in accordance with industry practice, including negotiated settlements. Certain of our natural gas pipelines have a regulated tariff rate mechanism requiring customer imbalance settlements each month at current market prices.

However, the vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are on-going and take place over several periods. In some cases, settlements of imbalances built up over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. For those gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2008 and 2007, our natural gas imbalance receivables, net of allowance for doubtful accounts, were $63.4 million and $73.9 million, respectively, and are reflected as a component of "Accounts and notes receivable – trade" on our Supplemental Consolidated Balance Sheets. At December 31, 2008 and 2007, our imbalance payables were $50.8 million and $48.7 million, respectively, and are reflected as a component of "Accrued product payables" on our Supplemental Consolidated Balance Sheets.

Noncontrolling Interest

As presented in our Supplemental Consolidated Balance Sheets, noncontrolling interest represents third-party and affiliate ownership interests in the net assets of our consolidated subsidiaries. For financial reporting purposes, the assets and liabilities of our controlled subsidiaries, including Duncan Energy Partners, TEPPCO and TEPPCO GP, are consolidated with those of our own, with any third-party or affiliate ownership in such amounts presented as noncontrolling interest. See Note 15 for information regarding noncontrolling interest.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in the results of operations for the respective period.

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. Under our depreciation policy for midstream energy assets, the remaining economic lives of such assets are limited to the estimated life of the natural resource basins (based on proved reserves at the time of the analysis) from which such assets derive their throughput or processing volumes. Our forecast of the remaining life for the applicable resource basins is based on several factors, including information published by the U.S. Energy Information Administration. Where appropriate, we use other depreciation methods (generally accelerated) for tax purposes.

Leasehold improvements are recorded as a component of property, plant and equipment. The cost of leasehold improvements is charged to earnings using the straight-line method over the shorter of the remaining lease term or the estimated useful lives of the improvements. We consider renewal terms that are deemed reasonably assured when estimating remaining lease terms.

Our assumptions regarding the useful economic lives and residual values of our assets may change in response to new facts and circumstances, which would change our depreciation amounts prospectively. Examples of such circumstances include, but are not limited to, the following: (i) changes in laws and regulations that limit the estimated economic life of an asset; (ii) changes in technology that render an asset obsolete; (iii) changes in expected salvage values; or (iv) significant changes in the forecast life of proved reserves of applicable resource basins, if any. See Note 10 for additional information regarding our property, plant and equipment, including a change in depreciation expense beginning January 1, 2008 resulting from a change in the estimated useful life of certain assets.

Certain of our plant operations entail periodic planned outages for major maintenance activities. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services and related items. We use the expense-as-incurred method for our planned major maintenance activities; however, the cost of annual planned major maintenance projects are deferred and recognized ratably over the remaining portion of the calendar year in which such projects occur.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value (accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-lived asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and New York Mercantile Exchange ("NYMEX") physical natural gas purchases. Additional cash may be restricted to maintain our positions as commodity prices fluctuate or deposit requirements change. At December 31, 2007, restricted cash also included amounts held by a third party trustee responsible for disbursing proceeds from our Petal GO Zone bond offering. During 2008, virtually all proceeds from the Petal GO Zone bonds were released by the trustee to fund construction costs associated with the expansion of our Petal, Mississippi storage facility. The following table presents the components of our restricted cash balances at the dates indicated:

	December 31,	
	2008	2007
Amounts held in brokerage accounts related to commodity hedging activities and physical natural gas purchases	$ 203.8	$ 53.1
Proceeds from Petal GO Zone bonds reserved for construction costs	--	17.9
Total restricted cash	$ 203.8	$ 71.0

Revenue Recognition

See Note 4 for information regarding our revenue recognition policies.

Start-Up and Organization Costs

Start-up costs and organization costs are expensed as incurred. Start-up costs are defined as one-time activities related to opening a new facility, introducing a new product or service, conducting activities in a new territory, pursuing a new class of customer, initiating a new process in an existing facility or some new operation. Routine ongoing efforts to improve existing facilities, products or services are not considered start-up costs. Organization costs include legal fees, promotional costs and similar charges incurred in connection with the formation of a business.

Note 3. Recent Accounting Developments

The accounting standard setting bodies have recently issued the following accounting guidance that will affect our future financial statements: SFAS 141(R), Business Combinations; FASB Staff Position ("FSP") SFAS 142-3, Determination of the Useful Life of Intangible Assets; SFAS 157, Fair Value Measurements; SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – An amendment of ARB 51; SFAS 161, Disclosures about Derivative Instruments and Hedging Activities – An Amendment of SFAS 133; Emerging Issues Task Force ("EITF") 08-6, Equity Method Investment Accounting Considerations; and EITF 07-4, Application of the Two Class Method Under SFAS 128, Earnings Per Share, to Master Limited Partnerships ("MLPs").

SFAS 141(R), Business Combinations. SFAS 141(R) replaces SFAS 141, Business Combinations and was effective January 1, 2009. SFAS 141(R) retains the fundamental requirements of SFAS 141 in that the acquisition method of accounting (previously termed the "purchase method") be used for all business combinations and for the "acquirer" to be identified in each business combination. SFAS 141(R) defines the acquirer as the entity that obtains control of one or more businesses in a business combination and establishes the acquisition date as the date that the acquirer achieves control. This new guidance also retains guidance in SFAS 141 for identifying and recognizing intangible assets separately from goodwill. SFAS 141(R) will have an impact on the way in which we evaluate acquisitions.

The objective of SFAS 141(R) is to improve the relevance, representational faithfulness, and comparability of the information a reporting entity provides in its financial reports about business combinations and their effects. To accomplish this, SFAS 141(R) establishes principles and requirements for how the acquirer:

§ Recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interests in the acquiree.

§ Recognizes and measures any goodwill acquired in the business combination or a gain resulting from a bargain purchase. SFAS 141(R) defines a bargain purchase as a business combination in which the total acquisition-date fair value of the identifiable net assets acquired exceeds the fair value of the consideration transferred plus any noncontrolling interest in the acquiree, and requires the acquirer to recognize that excess in net income as a gain attributable to the acquirer.

§ Determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

SFAS 141(R) also requires that direct costs of an acquisition (e.g. finder's fees, outside consultants, etc.) be expensed as incurred and not capitalized as part of the purchase price.

FSP FAS 142-3, Determination of the Useful Life of Intangible Assets. FSP 142-3 revised the factors that should be considered in developing renewal or extension assumptions used in determining the useful life of recognized intangible assets under SFAS 142, Goodwill and Other Intangible Assets. These revisions are intended to improve consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of such assets under SFAS 141(R) and other accounting guidance. The measurement and disclosure requirements of this new guidance will be applied to intangible assets acquired after January 1, 2009. Our adoption of this guidance is not expected to have a material impact on our consolidated financial statements.

SFAS 157, Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Although certain provisions of SFAS 157 were effective January 1, 2008, the remaining guidance of this new standard applicable to nonfinancial assets and liabilities was effective January 1, 2009. See Note 7 for information regarding fair value-related disclosures required for 2008 in connection with SFAS 157.

SFAS 157 applies 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 are required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop such measurements, and the effect of certain of the measurements on earnings (or changes in net assets) during a period. Our adoption of this guidance is not expected to have a material impact on our consolidated financial statements. SFAS 157 will impact the valuation of assets and liabilities (and related disclosures) in connection with future business combinations and impairment testing.

SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51. SFAS 160 established accounting and reporting standards for noncontrolling interests, which have been referred to as minority interests in prior accounting literature. SFAS 160 was effective January 1, 2009. A noncontrolling interest is that portion of equity in a consolidated subsidiary not attributable, directly or indirectly, to a reporting entity. This new standard requires, among other things, that (i) ownership interests of noncontrolling interests be presented as a component of equity on the balance sheet (i.e., elimination of the "mezzanine" presentation); (ii) elimination of minority interest expense as a line item on the statement of income and, as a result, that net income be allocated between the reporting entity and noncontrolling interests on the face of the statement of income; and (iii) enhanced disclosures regarding noncontrolling interests.

Effective January 1, 2009, we adopted the provisions of SFAS 160. The presentation and disclosure requirements of SFAS 160 have been applied retrospectively to the Supplemental Consolidated Financial Statements and Notes included in this Exhibit 99.2.

SFAS 161, Disclosures about Derivative Instruments and Hedging Activities - An Amendment of SFAS 133. SFAS 161 revised the disclosure requirements for derivative instruments and related hedging activities to provide users of financial statements with an enhanced understanding of (i) why and how an entity uses derivative instruments, (ii) how an entity accounts for derivative instruments and related hedged items under SFAS 133, Accounting for Derivative Instruments and Hedging Activities (including related interpretations), and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows.

SFAS 161 requires qualitative disclosures about objectives and strategies for using derivative instruments, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit risk-related contingent features in derivative instrument agreements. SFAS 161 was effective January 1, 2009 and we will apply its requirements beginning with the first quarter of 2009.

EITF 08-6, Equity Method Investment Accounting Considerations. EITF 08-6 clarifies the accounting for certain transactions and impairment considerations involving equity method investments under SFAS 141(R) and SFAS 160. EITF 08-6 generally requires that (i) transaction costs should be included in the initial carrying value of an equity method investment; (ii) an equity method investor shall not test separately an investee's underlying assets for impairment, rather such testing should be performed in accordance with Opinion 18 (i.e., on the equity method investment itself); (iii) an equity method investor shall account for a share issuance by an investee as if the investor had sold a proportionate share of its investment (any gain or loss to the investor resulting from the investee's share issuance shall be recognized in earnings); and (iv) a gain or loss should not be recognized when changing the method of accounting for an investment from the equity method to the cost method. EITF 08-6 was effective January 1, 2009.

EITF 07-4, Application of the Two Class Method Under SFAS 128, Earnings Per Share, to MLPs. EITF 07-4 prescribes the manner in which a MLP should allocate and present earnings per unit using the two-class method set forth in SFAS 128, Earnings Per Share. Under the two-class method, current period earnings are allocated to the general partner (including earnings attributable to any embedded incentive distribution rights ("IDRs")) and limited partners according to the distribution formula for available cash set forth in the MLP's partnership agreement.

Effective January 1, 2009, we adopted the provisions of EITF 07-4. The requirements of EITF 07-4 have been applied retrospectively to the Supplemental Consolidated Financial Statements and Notes included in this Exhibit 99.2 (see Note 19).

Note 4. Revenue Recognition

In general, we recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer's price is fixed or determinable and (iv) collectability is reasonably assured. The following information provides a general description of our underlying revenue recognition policies by business segment:

NGL Pipelines & Services

NGL Pipelines & Services includes our (i) natural gas processing business and related NGL marketing activities; (ii) NGL pipelines, including our Mid-America Pipeline System; (iii) NGL and related product storage facilities; and (iv) NGL fractionation facilities. This segment also includes our import and export terminal operations.

In our natural gas processing business, we enter into margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid-contracts (i.e. mixed percent-of-liquids and fee-based) and keepwhole contracts. Under margin-band and keepwhole contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract and sell is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract. Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer's behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer.

Our NGL marketing activities generate revenues from the sale of NGLs obtained from either our natural gas processing activities or purchased from third parties on the open market. Revenues from these sales contracts are recognized when the NGLs are delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Under our NGL pipeline transportation contracts and tariffs, revenue is recognized when volumes have been delivered to customers. Revenue from these contracts and tariffs is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Transportation fees charged under these arrangements are either contractual or regulated by governmental agencies such as the Federal Energy Regulatory Commission ("FERC").

We collect storage revenues under our NGL and related product storage contracts based on the number of days a customer has volumes in storage multiplied by a storage rate (as defined in each contract). Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for customers in our underground storage wells. Under these agreements, revenue is recognized ratably over the specified reservation period. Excess storage fees are collected when customers exceed their reservation amounts and are recognized in the period of occurrence. In addition, we charge our customers throughput fees based on volumes injected and withdrawn from the storage facility, which are recognized as the service is provided.

We enter into fee-based arrangements and percent-of-liquids contracts for the NGL fractionation services we provide to customers. Under such fee-based arrangements, revenue is recognized in the period services are provided. Such fee-based arrangements typically include a base-processing fee (typically in cents per gallon) that is subject to adjustment for changes in certain fractionation expenses (e.g. natural gas fuel costs). Certain of our NGL fractionation facilities generate revenues using percent-of-liquids contracts. Such contracts allow us to retain a contractually determined percentage of the customer's fractionated NGL products as payment for services rendered. Revenue is recognized from such arrangements when we sell and deliver the retained NGLs to customers.

Revenues from product terminaling activities (applicable to our import and export operations) are recorded in the period such services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded. With respect to export operations, revenues may also include demand payments charged to customers who reserve the use of our export facilities and later fail to use them. Demand fee revenues are recognized when the customer fails to utilize the specified export facility as required by contract.

Onshore Natural Gas Pipelines & Services

Onshore Natural Gas Pipelines & Services includes our onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. We own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our natural gas marketing activities.

In general, our onshore natural gas pipelines generate revenues from gathering and transportation agreements where shippers are billed a fee per unit of volume transported (typically in million British thermal units, or “MMBtus”) multiplied by the volume gathered or delivered. The fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Certain of our onshore natural gas pipelines may also offer firm capacity reservation services whereby the shipper pays a contractually stated fee based on the level of capacity reserved in our pipelines whether or not the shipper actually ships the reserved quantity of natural gas. Revenues under firm capacity reservation agreements are recognized in the period the services are provided.

Revenues from natural gas storage contracts typically have two components: (i) a monthly demand payment, which is associated with storage capacity reservations, and (ii) a storage fee per unit of volume held at each location. Revenues from demand payments are recognized during the period the customer reserves capacity. Revenues from storage fees are recognized in the period the services are provided.

Our natural gas marketing activities generate revenues from the sale of natural gas purchased from third parties on the open market. Revenues from these sales contracts are recognized when the natural gas is delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Onshore Crude Oil Pipelines & Services

Onshore Crude Oil Pipelines & Services includes our onshore crude oil pipelines and related storage terminals. This segment also includes our related crude oil marketing activities.

Revenue from crude oil transportation is generally based upon a fixed fee per barrel transported multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Revenues associated with these arrangements are recognized when volumes have been delivered.

Under our crude oil terminaling agreements, we charge customers for crude oil storage based on the number of days a customer has volumes in storage multiplied by a storage rate (as defined in each contract). Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for customers in our underground storage wells. Under these agreements, revenue is recognized ratably over the specified reservation period. In addition, we charge our customers throughput (or “pumpover”) fees based on volumes withdrawn from our terminals. Crude oil storage revenues are recognized ratably over the length of the storage period. Revenues are also generated from trade documentation and terminaling services and are recognized as services are completed.

Our crude oil marketing activities generate revenues from the sale and delivery of crude oil obtained from producers at the wellhead or through bulk purchases from third parties on the open market at pipelines, terminal facilities and trading locations. These sales contracts generally settle with the physical delivery of crude oil to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Offshore Pipelines & Services

Offshore Pipelines & Services includes our (i) offshore natural gas pipelines strategically located to serve production areas including some of the most active drilling and development regions in the Gulf of Mexico, (ii) offshore Gulf of Mexico crude oil pipeline systems and (iii) six multi-purpose offshore hub platforms located in the Gulf of Mexico with crude oil or natural gas processing capabilities.

Our offshore natural gas pipelines generate revenues through fee-based contracts or tariffs where revenues are equal to the product of a fee per unit of volume (typically in MMBtus) multiplied by the volume of natural gas transported. Revenues associated with these fee-based contracts and tariffs are recognized when natural gas volumes have been delivered.

The majority of revenues from our offshore crude oil pipelines are generated based upon a transportation fee per unit of volume (typically in barrels) multiplied by the volume delivered to the customer. A substantial portion of the revenues generated by our offshore crude oil pipeline systems are attributable to long-term transportation agreements with producers. The revenues we earn for our services are dependent on the volume of crude oil to be delivered and the level of fees charged to customers.

Revenues from offshore platform services generally consist of demand payments and commodity charges. Revenues from platform services are recognized in the period the services are provided. Demand fees represent charges to customers served by our offshore platforms regardless of the volume the customer delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per million cubic feet of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand payments and commodity charges, but demand payments generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. Our Independence Hub and Marco Polo offshore platforms earn a significant amount of demand revenues. The Independence Hub platform will earn $54.6 million of demand revenues annually through March 2012. The Marco Polo platform will earn $2.1 million of demand revenues monthly through March 2009.

Petrochemical & Refined Products Services

Petrochemical & Refined Products Services includes our (i) propylene fractionation plants and related activities, (ii) butane isomerization facilities, (iii) octane enhancement facility, (iv) refined products pipelines, including our Products Pipeline System, and related activities and (v) marine transportation assets and other services.

Our propylene fractionation and butane isomerization facilities generate revenues through fee-based arrangements, which typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation and butane isomerization. Revenues resulting from such agreements are recognized in the period the services are provided.

Our marketing activities classified within this segment generate revenues from the sale of propylene, isooctane and other products, including lubrication oils, obtained from either our processing activities or purchased from third parties on the open market. Revenues from these sales contracts are recognized when such products are delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Our refined products pipelines, including our Products Pipeline System, generate revenues through fee-based contracts or tariffs as customers are billed a fixed fee per barrel of liquids transported multiplied by the volume delivered. Transportation fees charged under these arrangements are either contractual or regulated by governmental agencies such as the FERC. Revenues associated with these fee-based contracts and tariffs are recognized when volumes have been delivered. Revenues from our refined products storage facilities are based on the number of days a customer has volumes in storage multiplied by a storage rate (as defined in each contract). Under these contracts, revenue is recognized ratably over the length of the storage period. Revenues from product terminaling activities are recorded in the period such services are provided. Customers are typically billed a fee per unit of volume loaded.

Revenue is also generated from the provision of inland and offshore transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges. Under our marine services transportation contracts, revenue is recognized over the transit time of individual tows as determined on an individual contract basis, which is generally less than ten days in duration. Revenue from these contracts is generally based on set day rates or a set fee per cargo movement. Most of the marine services transportation contracts include escalation provisions to recover increased operating costs such as incremental increases in labor. The costs of fuel, substantially all of which is a pass through expense, and other specified operational fees and costs are directly reimbursed by the customer under most of the contracts.

The results of operations from the distribution of lubrication oils and specialty chemicals and the bulk transportation of fuels are dependent on the sales price or transportation fees that we charge our customers. Revenue is recognized for sales transactions when the product is delivered and for transportation arrangements when the product is delivered.

Note 5. Accounting for Equity Awards

We account for equity awards in accordance with SFAS 123(R), Share-Based Payment. SFAS 123(R) requires us to recognize compensation expense related to equity awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying common units on the date of grant. The fair value of other equity awards is estimated using the Black-Scholes option pricing model. The fair value of an equity-classified award (such as a restricted unit award) is amortized to earnings on a straight-line basis over the requisite service or vesting period. Compensation expense for liability-classified awards (such as unit appreciation rights (“UARs”)) is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability-classified awards are settled in cash upon vesting.

As used in the context of the EPCO plans, the term “restricted unit” represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires.

Upon our adoption of SFAS 123(R), we recognized, as a benefit, a cumulative effect of a change in accounting principle of $1.5 million based on the SFAS 123(R) requirement to recognize compensation expense based upon the grant date fair value of an equity award and the application of an estimated forfeiture rate to unvested awards. In addition, previously recognized deferred compensation expense of $14.6 million related to our restricted common units was reversed on January 1, 2006.

Prior to our adoption of SFAS 123(R), we did not recognize any compensation expense related to unit options; however, compensation expense was recognized in connection with awards granted by EPE Unit I and the issuance of restricted units. The effects of applying SFAS 123(R) during the year ended December 31, 2006 did not have a material effect on our net income or basic and diluted earnings per unit. Since we adopted SFAS 123(R) using the modified prospective method, we have not restated the financial statements of prior periods to reflect this new standard. The following tables summarize our equity compensation amounts by plan for each of the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
Employee Partnerships	$ 6.3	$ 4.3	$ 2.1
EPCO 1998 Long-Term Incentive Plan ("EPCO 1998 Plan"):			
Unit options	0.4	4.4	0.7
Restricted units	9.9	8.4	5.2
Total EPCO 1998 Plan (1)	10.3	12.8	5.9
Enterprise Products 2008 Long-Term Incentive Plan ("EPD 2008 LTIP"):			
Unit options	0.1	--	--
Total EPD 2008 LTIP	0.1	--	--
TEPPCO 1999 Phantom Unit Retention Plan ("TEPPCO 1999 Plan")	(0.1)	0.9	0.9
TEPPCO 2000 Long-Term Incentive Plan ("TEPPCO 2000 LTIP")	(0.3)	0.4	0.4
TEPPCO 2005 Phantom Unit Plan ("TEPPCO 2005 Phantom Unit Plan")	(0.1)	1.0	1.2
EPCO 2006 TPP Long-Term Incentive Plan ("TEPPCO 2006 LTIP"):			
Unit options	0.2	0.1	--
Restricted units	1.0	0.3	--
UARs	--	0.1	--
Total TEPPCO 2006 LTIP	1.2	0.5	--
Total compensation expense	$ 17.4	$ 19.9	$ 10.5

(1) Amounts for the year ended December 31, 2007 include $4.6 million associated with the resignation of our general partner's former chief executive officer.

Employee Partnerships

As long-term incentive arrangements, EPCO has granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, "profits interests" in seven limited partnerships (the "Employee Partnerships"), which are private company affiliates of EPCO. The employees were issued Class B limited partner interests and admitted as Class B limited partners in the Employee Partnerships without capital contributions. As discussed and defined in Note 1, the Employee Partnerships are: EPE Unit I; EPE Unit II; EPE Unit III; Enterprise Unit; EPCO Unit; TEPPCO Unit and TEPPCO Unit II. Enterprise Unit, EPCO Unit, TEPPCO Unit and TEPPCO Unit II were formed in 2008.

The Class B limited partner interests entitle each holder to participate in the appreciation in value of the publicly traded limited partner units owned by the underlying Employee Partnership. The Employee Partnerships own either Enterprise GP Holdings units ("EPE units") or Enterprise Products Partners' common units ("EPD units") or both. TEPPCO Unit and TEPPCO Unit II owned units of TEPPCO ("TPP units") prior to their conversion to EPD units in connection with the TEPPCO Merger. The Class B limited partner interests are subject to forfeiture if the participating employee's employment with EPCO is terminated prior to vesting, with customary exceptions for death, disability and certain retirements and upon certain change of control events.

We account for the profits interest awards under SFAS 123(R). As a result, the compensation expense attributable to these awards is based on the estimated grant date fair value of each award. An allocated portion of the fair value of these equity-based awards is charged to us under the EPCO administrative services agreement ("ASA") (see Note 17). We are not responsible for reimbursing EPCO for any expenses of the Employee Partnerships, including the value of any contributions of cash or limited partner units made by private company affiliates of EPCO at the formation of each Employee Partnership. However, pursuant to the ASA, beginning in February 2009, we will reimburse EPCO for our allocated share of distributions of cash or securities made to the Class B limited partners of EPCO Unit and TEPPCO Unit II.

Each Employee Partnership has a single Class A limited partner, which is a privately held indirect subsidiary of EPCO, and a varying number of Class B limited partners. At formation, the Class A limited partner either contributes cash or limited partner units it owns to the Employee Partnership. If cash is contributed, the Employee Partnership uses these funds to acquire limited partner units on the open market. In general, the Class A limited partner earns a preferred return (either fixed or variable depending on the partnership agreement) on its investment ("Capital Base") in the Employee Partnership and any residual quarterly cash amounts, if any, are distributed to the Class B limited partners. Upon liquidation, Employee Partnership assets having a fair market value equal to the Class A limited partner's Capital Base, plus any preferred return for the period in which liquidation occurs, will be distributed to the Class A limited partner. Any remaining assets will be distributed to the Class B limited partner(s) as a residual profits interest.

The following table summarizes key elements of each Employee Partnership as of December 31, 2008:

Employee Partnership	Description of Assets	Initial Class A Capital Base	Class A Partner Preferred Return	Award Vesting Date (1)	Grant Date Fair Value of Awards (2)	Unrecognized Compensation Cost (3)
EPE Unit I	1,821,428 EPE units	$51.0 million	4.50% to 5.725% (4)	November 2012	$17.0 million	$9.3 million
EPE Unit II	40,725 EPE units	$1.5 million	4.50% to 5.725% (4)	February 2014	$0.3 million	$0.2 million
EPE Unit III	4,421,326 EPE units	$170.0 million	3.80%	May 2014	$32.7 million	$25.1 million
Enterprise Unit	881,836 EPE units 844,552 EPD units	$51.5 million	5.00%	February 2014	$4.2 million	$3.7 million
EPCO Unit	779,102 EPD units	$17.0 million	4.87%	November 2013	$7.2 million	$7.0 million
TEPPCO Unit	241,380 TPP units	$7.0 million	4.50% to 5.725%	September 2013	$2.1 million	$1.7 million
TEPPCO Unit II	123,185 TPP units	$3.1 million	6.31%	November 2013	$1.4 million	$1.4 million

(1) The vesting date may be accelerated for change of control and other events as described in the underlying partnership agreements.
(2) Our estimated grant date fair values were determined using a Black-Scholes option pricing model and reflect adjustments for forfeitures, regrants and other modifications. See following table for information regarding our fair value assumptions.
(3) Unrecognized compensation cost represents the total future expense to be recognized by the EPCO group of companies as of December 31, 2008. We expect to recognize our allocated share of such costs in the future in accordance with the ASA. The period over which the unrecognized compensation cost will be recognized is as follows for each Employee Partnership: 3.9 years, EPE Unit I; 5.1 years, EPE Unit II; 5.4 years, EPE Unit III; 5.1 years, Enterprise Unit; 4.9 years, EPCO Unit; 4.7 years, TEPPCO Unit; and 4.9 years, TEPPCO Unit II.
(4) In July 2008, the Class A preferred return was reduced from 6.25% to the floating amounts presented.

The following table summarizes the assumptions we used in deriving the estimated grant date fair value for each of the Employee Partnerships using a Black-Scholes option pricing model:

Employee Partnership	Expected Life of Award	Risk-Free Interest Rate	Expected Distribution Yield		Expected Unit Price Volatility	
			EPE/EPD units	TPP units	EPE/EPD units	TPP units
EPE Unit I	3 to 5 years	2.7% to 5.0%	3.0% to 4.8%	n/a	16.6% to 30.0%	n/a
EPE Unit II	5 to 6 years	3.3% to 4.4%	3.8% to 4.8%	n/a	18.7% to 19.4%	n/a
EPE Unit III	4 to 6 years	3.2% to 4.9%	4.0% to 4.8%	n/a	16.6% to 19.4%	n/a
Enterprise Unit	6 years	2.7% to 3.9%	4.5% to 8.0%	n/a	15.3% to 22.1%	n/a
EPCO Unit	5 years	2.4%	11.1%	n/a	50.0%	n/a
TEPPCO Unit	5 years	2.9%	n/a	7.3%	n/a	16.4%
TEPPCO Unit II	5 years	2.4%	n/a	13.9%	n/a	66.4%

EPCO 1998 Plan

Unit option awards. Under the EPCO 1998 Plan, non-qualified incentive options to purchase a fixed number of our common units may be granted to key employees of EPCO who perform management, administrative or operational functions for us. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. During 2008, in response to changes in the federal tax code applicable to certain types of equity awards, we amended the terms of certain of our outstanding unit options. In general, the expiration dates of these awards were modified from May and August 2017 to December 2012.

In order to fund its obligations under the EPCO 1998 Plan, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit options, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The fair value of each unit option is estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions including expected life of the options, risk-free interest rates, expected distribution yield on our common units, and expected unit price volatility of our common units. In general, our assumption of expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of historical option activity. Our selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility is estimated based on several factors, which include an analysis of our historical unit price volatility and distribution yield over a period equal to the expected life of the option.

The EPCO 1998 Plan provides for the issuance of up to 7,000,000 of our common units. After giving effect to outstanding option awards at December 31, 2008 and the issuance and forfeiture of restricted unit awards through December 31, 2008, a total of 814,674 additional common units could be issued under the EPCO 1998 Plan.

The following table presents unit option activity under the EPCO 1998 Plan for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2005	2,082,000	$ 22.16		
Granted (2)	590,000	24.85		
Exercised	(211,000)	15.95		
Forfeited	(45,000)	24.28		
Outstanding at December 31, 2006	2,416,000	23.32		
Granted (3)	895,000	30.63		
Exercised	(256,000)	19.26		
Settled or forfeited (4)	(740,000)	24.62		
Outstanding at December 31, 2007 (5)	2,315,000	26.18		
Exercised	(61,500)	20.38		
Forfeited	(85,000)	26.72		
Outstanding at December 31, 2008 (6)	2,168,500	26.32	5.19	$ --
Options exercisable at:				
December 31, 2006	591,000	$ 20.85	5.11	$ 4,808
December 31, 2007	335,000	$ 22.06	3.96	$ 3,291
December 31, 2008 (6)	548,500	$ 21.47	4.08	$ --

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.
(2) The total grant date fair value of these unit options issued during 2006 was $1.2 million based on the following assumptions: (i) weighted-average expected life of options of seven years; (ii) weighted-average risk-free interest rate of 5.0%; (iii) weighted-average expected distribution yield on our common units of 8.9%; and (iv) weighted-average expected unit price volatility on our common units of 23.5%.
(3) The total grant date fair value of these unit options issued during 2007 was $2.4 million based on the following assumptions: (i) expected life of options of seven years; (ii) weighted-average risk-free interest rate of 4.8%; (iii) weighted-average expected distribution yield on our common units of 8.4%; and (iv) weighted-average expected unit price volatility on our common units of 23.2%.
(4) Includes the settlement of 710,000 options in connection with the resignation of our general partner's former chief executive officer.
(5) During 2008, we amended the terms of certain of our outstanding unit options. In general, the expiration dates of these awards were modified from May and August 2017 to December 2012.
(6) We were committed to issue 2,168,500 and 2,315,000 of our common units at December 31, 2008 and 2007, respectively, if all outstanding options awarded under the EPCO 1998 Plan (as of these dates) were exercised. An additional 365,000, 480,000 and 775,000 of these options are exercisable in 2009, 2010 and 2012, respectively.

The total intrinsic value of option awards exercised during the years ended December 31, 2008, 2007 and 2006 were $0.6 million, $3.0 million and $2.2 million, respectively. At December 31, 2008, the estimated total unrecognized compensation cost related to nonvested unit option awards granted under the EPCO 1998 Plan was $1.7 million. We expect to recognize this cost over a weighted-average period of 2.1 years in accordance with the ASA.

During the years ended December 31, 2008 and 2007, we received cash of $0.7 million and $7.5 million, respectively, from the exercise of option awards granted under the EPCO 1998 Plan. Conversely, our option-related reimbursements to EPCO were $0.6 million and $3.0 million, respectively.

Restricted unit awards. Under the EPCO 1998 Plan, we may also issue restricted common units to key employees of EPCO and directors of our general partner. In general, the restricted unit awards allow recipients to acquire the underlying common units at no cost to the recipient once a defined cliff vesting period expires, subject to certain forfeiture provisions. The restrictions on such units generally lapse four years from the date of grant. Compensation expense is recognized on a straight-line basis over the vesting period. Fair value of such restricted units is based on the market price of the underlying common units on the date of grant and an allowance for estimated forfeitures.

Each recipient is also entitled to cash distributions equal to the product of the number of restricted units outstanding for the participant and the cash distribution per unit paid by us to our unitholders. Since restricted units are issued securities, such distributions are reflected as a component of cash distributions to partners as shown on our Supplemental Statements of Consolidated Cash Flows. We paid $3.9 million, $2.6 million and $1.6 million in cash distributions with respect to restricted units during the years ended December 31, 2008, 2007 and 2006, respectively.

The following table presents restricted unit activity under the EPCO 1998 Plan for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted units at December 31, 2005	751,604	
Granted (2)	466,400	$ 25.21
Vested	(42,136)	$ 24.02
Forfeited	(70,631)	$ 22.86
Restricted units at December 31, 2006	1,105,237	
Granted (3)	738,040	$ 25.61
Vested	(4,884)	$ 25.28
Forfeited	(36,800)	$ 23.51
Settled (4)	(113,053)	$ 23.24
Restricted units at December 31, 2007	1,688,540	
Granted (5)	766,200	$ 24.93
Vested	(285,363)	$ 23.11
Forfeited	(88,777)	$ 26.98
Restricted units at December 31, 2008	2,080,600	

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued. The weighted-average grant date fair value per unit for forfeited and vested awards is determined before an allowance for forfeitures.
(2) Aggregate grant date fair value of restricted unit awards issued during 2006 was $10.8 million based on grant date market prices of our common units ranging from $24.85 to $27.45 per unit and estimated forfeiture rates ranging from 7.8% to 9.8%.
(3) Aggregate grant date fair value of restricted unit awards issued during 2007 was $18.9 million based on grant date market prices of our common units ranging from $28.00 to $31.83 per unit and estimated forfeiture rates ranging from 4.6% to 17.0%.
(4) Reflects the settlement of restricted units in connection with the resignation of our general partner's former chief executive officer.
(5) Aggregate grant date fair value of restricted unit awards issued during 2008 was $19.1 million based on grant date market prices of our common units ranging from $25.00 to $32.31 per unit and an estimated forfeiture rate of 17.0%.

The total fair value of restricted unit awards that vested during the year ended December 31, 2008 was $6.6 million. At December 31, 2008, the estimated total unrecognized compensation cost related to restricted unit awards granted under the EPCO 1998 Plan was $31.5 million. We expect to recognize our share of this cost over a weighted-average period of 2.3 years in accordance with the ASA.

Phantom unit awards. The EPCO 1998 Plan also provides for the issuance of phantom unit awards. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the market closing price of our common units on the redemption date. Each participant is required to redeem their phantom units as they vest, which typically is four years from the date the award is granted. No phantom unit awards have been issued to date under the EPCO 1998 Plan.

The EPCO 1998 Plan also provides for the award of distribution equivalent rights ("DERs") in tandem with its phantom unit awards. A DER entitles the participant to cash distributions equal to the product of the number of phantom units outstanding for the participant and the cash distribution rate paid by us to our unitholders. No DERs have been issued as of December 31, 2008 under the EPCO 1998 Plan.

EPD 2008 LTIP

On January 29, 2008, our unitholders approved the EPD 2008 LTIP, which provides for awards of our common units and other rights to our non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the EPD 2008 LTIP may be granted in the form of unit options, restricted units, phantom units, UARs and DERs. The EPD 2008 LTIP is administered by EPGP's Audit, Conflicts and Governance ("ACG") Committee. The EPD 2008 LTIP provides for the issuance of up to 10,000,000 of our common units. After giving effect to option awards outstanding at December 31, 2008, a total of 9,205,000 additional common units could be issued under the EPD 2008 LTIP.

The EPD 2008 LTIP may be amended or terminated at any time by the Board of Directors of EPCO or EPGP's ACG Committee; however, the rules of the NYSE require that any material amendment, such as a significant increase in the number of common units available under the plan or a change in the types of awards available under the plan, would require the approval of our unitholders. The ACG Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in, awards under the plan in specified circumstances. The EPD 2008 LTIP is effective until the earlier of January 29, 2018 or the time which all available units under the incentive plan have been delivered to participants or the time of termination of the plan by EPCO or EPGP's ACG Committee.

Unit option awards. The exercise price of unit options awarded to participants is determined by the ACG Committee (at its discretion) at the date of grant and may be no less than the fair market value of our common units at the date of grant. The following table presents unit option activity under the EPD 2008 LTIP for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)
Outstanding at January 1, 2008	--		
Granted (1)	795,000	$ 30.93	
Outstanding at December 31, 2008 (2)	795,000	$ 30.93	5.00

(1) Aggregate grant date fair value of these unit options issued during 2008 was $1.6 million based on the following assumptions: (i) a grant date market price of our common units of $30.93 per unit; (ii) expected life of options of 4.7 years; (iii) risk-free interest rate of 3.3%; (iv) expected distribution yield on our common units of 7.0%; (v) expected unit price volatility on our common units of 19.8%; and (vi) an estimated forfeiture rate of 17.0%.
(2) The 795,000 units outstanding at December 31, 2008 will become exercisable in 2013.

At December 31, 2008, the estimated total unrecognized compensation cost related to nonvested unit options granted under the EPD 2008 LTIP was $1.3 million. We expect to recognize our share of this cost over a remaining period of 3.4 years in accordance with the ASA.

Phantom unit awards. The EPD 2008 LTIP also provides for the issuance of phantom unit awards. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the market closing price of our common units on the redemption date. Each participant is required to redeem their phantom units as they vest, which typically is three years from the date the award is granted. There were a total of 4,400 phantom units granted under the EPD 2008 LTIP during the fourth quarter of 2008 and outstanding at December 31, 2008. These awards cliff vest in 2011. At December 31, 2008, we had an accrued liability of $5 thousand for compensation related to these phantom unit awards.

DEP GP UARs

The non-employee directors of DEP GP, the general partner of Duncan Energy Partners, have been granted UARs in the form of letter agreements. These liability awards are not part of any established long-term incentive plan of EPCO, Enterprise GP Holdings, Duncan Energy Partners or us. The compensation expense associated with these awards is recognized by DEP GP, which is our consolidated subsidiary. These UARs entitle each non-employee director to receive a cash payment on the vesting date equal to the excess, if any, of the fair market value of EPE units (determined as of a future vesting date) over the grant date fair value. If a director resigns prior to vesting, his UAR awards are forfeited. These UARs are accounted for similar to liability awards under SFAS 123(R) since they will be settled with cash.

As of December 31, 2008, a total of 90,000 UARs had been granted to non-employee directors of DEP GP that cliff vest in 2012. If a director resigns prior to vesting, his UAR awards are forfeited. The grant date fair value with respect to these UARs is based on an EPE unit price of $36.68.

TEPPCO 1999 Plan

The TEPPCO 1999 Plan provides for the issuance of phantom unit awards as incentives to key employees of EPCO working on behalf of TEPPCO. These liability awards are settled for cash based on the fair market value of the vested portion of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the closing price of TEPPCO's units on the NYSE on the redemption date. Each participant is required to redeem their phantom units as they vest. In addition, each participant is entitled to cash distributions equal to the product of the number of phantom unit awards granted under the TEPPCO 1999 Plan and the cash distribution per unit paid by TEPPCO on its units. Grants under the 1999 Plan are subject to forfeiture if the participant's employment with EPCO is terminated.

A total of 18,600 and 31,600 phantom units were outstanding under the TEPPCO 1999 Plan at December 31, 2008 and 2007, respectively. In April 2008, 13,000 phantom units vested and $0.4 million was paid out to a participant in the second quarter of 2008. The awards outstanding at December 31, 2008 cliff vest as follows: 13,000 in April 2009 and 5,600 in January 2010. At December 31, 2008 and 2007, we had accrued liability balances of $0.4 million and $1.0 million, respectively, related to the TEPPCO 1999 Plan. For the years ended December 31, 2008 and 2007, phantom unitholders under the TEPPCO 1999 Plan received $62 thousand and $95 thousand in cash distributions, respectively. Since phantom units do not represent issued securities of TEPPCO, the cash payments with respect to these phantom units are expensed as paid.

TEPPCO 2000 LTIP

The TEPPCO 2000 LTIP provides key employees of EPCO working on behalf of TEPPCO incentives to achieve improvements in TEPPCO's financial performance. Generally, upon the close of a three-year performance period, each recipient will receive a cash payment equal to (i) the applicable "performance percentage" (as defined in the award agreement) multiplied by (ii) the number of phantom units granted under the TEPPCO 2000 LTIP multiplied by (iii) the average of the closing prices of TEPPCO units over the ten consecutive days immediately preceding the last day of the specified performance period. In addition, during the performance period, each participant is entitled to cash distributions equal to the product of the number of phantom units granted under the TEPPCO 2000 LTIP and the cash distribution per unit paid by TEPPCO on its units. Grants under the TEPPCO 2000 LTIP are accounted for as liability awards and are subject to forfeiture if the recipient's employment with EPCO is terminated, with customary exceptions for death, disability or retirement.

A participant's "performance percentage" is based upon an improvement in Economic Value Added for TEPPCO during a given three-year performance period over the Economic Value Added for the three-year period immediately preceding the performance period. The term "Economic Value Added" means TEPPCO's average annual EBITDA for the performance period minus the product of TEPPCO's average asset base and its cost of capital for the performance period. In this context, EBITDA means

TEPPCO's earnings before net interest expense, other income, depreciation and amortization and TEPPCO's proportional interest in the EBITDA of its joint ventures, except that the chief executive officer of TEPPCO may exclude gains or losses from extraordinary, unusual or non-recurring items. Average asset base means the quarterly average, during the performance period, of TEPPCO's gross carrying value of property, plant and equipment, plus long-term inventory, and the gross carrying value of intangible assets and equity investments. TEPPCO's cost of capital is determined at the date each award was granted.

At December 31, 2008, a total of 11,300 phantom units were outstanding under the TEPPCO 2000 LTIP that cliff vested on December 31, 2008 and will be paid out to participants in the first quarter of 2009. On December 31, 2007, 19,700 phantom units were outstanding under the TEPPCO 2000 LTIP. On December 31, 2007, 8,400 phantom units vested and $0.5 million was paid out to participants in the first quarter of 2008. At December 31, 2008 and 2007, we had accrued liability balances of $0.2 million and $0.9 million, respectively, related to the TEPPCO 2000 LTIP. After payout in the first quarter of 2009 on awards which vested on December 31, 2008, there will be no remaining phantom units outstanding under the TEPPCO 2000 LTIP. For the years ended December 31, 2008 and 2007, phantom unitholders under the TEPPCO 2000 LTIP received $38 thousand and $54 thousand in cash distributions, respectively.

TEPPCO 2005 Phantom Unit Plan

The TEPPCO 2005 Phantom Unit Plan provides key employees of EPCO working on behalf of TEPPCO incentives to achieve improvements in TEPPCO's financial performance. Generally, upon the close of a three-year performance period, the recipient will receive a cash payment equal to (i) the recipient's vested percentage (as defined in the award agreement) multiplied by (ii) the number of phantom units granted under the TEPPCO 2005 Phantom Unit Plan multiplied by (iii) the average of the closing prices of TEPPCO units over the ten consecutive days immediately preceding the last day of the specified performance period. In addition, during the performance period, each recipient is entitled to cash distributions equal to the product of the number of phantom units granted under the TEPPCO 2005 Phantom Unit Plan and the cash distribution per unit paid by TEPPCO on its units. Grants under the TEPPCO 2005 Phantom Unit Plan are accounted for as liability awards and are subject to forfeiture if the recipient's employment with EPCO is terminated, with customary exceptions for death, disability or retirement.

Generally, a participant's vested percentage is based upon an improvement in TEPPCO's EBITDA during a given three-year performance period over TEPPCO's EBITDA for the three-year period preceding the performance period. In this context, EBITDA means TEPPCO's earnings before noncontrolling interest, net interest expense, other income, income taxes, depreciation and amortization and TEPPCO's proportional interest in the EBITDA of its joint ventures, except that the chief executive officer of TEPPCO may exclude gains or losses from extraordinary, unusual or non-recurring items.

At December 31, 2008 a total of 36,600 phantom units were outstanding under the TEPPCO 2005 Phantom Unit Plan that cliff vested on December 31, 2008 and will be paid out to participants in the first quarter of 2009. On December 31, 2007, 74,400 phantom units were outstanding under the TEPPCO 2005 Phantom Unit Plan. On December 31, 2007, 36,200 phantom units vested and $1.6 million was paid out to participants in the first quarter of 2008. At December 31, 2008 and 2007, we had accrued liability balances of $0.6 million and $2.6 million, respectively, related to the TEPPCO 2005 Phantom Unit Plan. After the payout in the first quarter of 2009 on awards which vested on December 31, 2008, there will be no remaining phantom units outstanding under the TEPPCO 2005 Phantom Unit Plan. For the years ended December 31, 2008 and 2007, phantom unitholders under the TEPPCO 2005 Phantom Unit Plan received $0.1 million and $0.2 million in cash distributions, respectively.

TEPPCO 2006 LTIP

The TEPPCO 2006 LTIP provide for awards of TEPPCO units and other rights to its non-employee directors and to certain employees of EPCO working on behalf of TEPPCO. Awards granted under the TEPPCO 2006 LTIP may be in the form of restricted units, phantom units, unit options, UARs and DERs. The TEPPCO 2006 LTIP provides for the issuance of up to 5,000,000 units of TEPPCO in connection with these awards. After giving effect to outstanding unit options and restricted units at December 31, 2008, and the forfeiture of restricted units through December 31, 2008, a total of 4,487,084 additional units of TEPPCO could be issued under the TEPPCO 2006 LTIP in the future.

Unit option awards. The following table presents unit option activity under the TEPPCO 2006 LTIP for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)
Option award activity during 2007			
Granted (1) (2)	155,000	$ 45.35	
Outstanding at December 31, 2007	155,000	$ 45.35	
Granted (3)	200,000	$ 35.86	
Outstanding at December 31, 2008 (4)	355,000	$ 40.00	4.57

(1) The total grant date fair value of these unit options issued during 2007 was $0.4 million based on the following assumptions: (i) expected life of the option of seven years; (ii) risk-free interest rate of 4.78%; (iii) expected distribution yield on TEPPCO units of 7.92%; and (iv) expected unit price volatility on TEPPCO's units of 18.03%.
(2) During 2008, we amended the terms of the outstanding unit options. In general, the expiration dates of these awards granted on May 22, 2007 were modified from May 22, 2017 to December 31, 2012.
(3) The total grant date fair value of these unit options issued on May 19, 2008 was $0.3 million based on the following assumptions: (i) expected life of the option of 4.7 years; (ii) risk-free interest rate of 3.3%; (iii) expected distribution yield on TEPPCO units of 7.9%; (iv) estimated forfeiture rate of 17.0%; and (v) expected unit price volatility on TEPPCO's units of 18.7%.
(4) No unit options were exercisable at December 31, 2008.

At December 31, 2008, the estimated total unrecognized compensation cost related to nonvested unit option awards granted under the TEPPCO 2006 LTIP was $0.6 million. We expect to recognize our share of this cost over a weighted-average period of 3.0 years in accordance with the ASA.

Restricted unit awards. The following table presents restricted unit activity under the TEPPCO 2006 LTIP for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted unit activity during 2007		
Granted (2)	62,900	$ 37.64
Forfeited	(500)	$ 37.64
Restricted units at December 31, 2007	62,400	
Granted (3)	96,900	$ 29.54
Vested	(1,000)	$ 40.61
Forfeited	(1,000)	$ 35.86
Restricted units at December 31, 2008	157,300	

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued. The weighted-average grant date fair value per unit for forfeited and vested awards is determined before an allowance for forfeitures.
(2) Aggregate grant date fair value of restricted unit awards issued during 2007 was $2.4 million based on a grant date market price of TEPPCO's units of $45.35 per unit and an estimated forfeiture rate of 17.0%.
(3) Aggregate grant date fair value of restricted unit awards issued during 2008 was $2.8 million based on grant date market prices of TEPPCO's units ranging from $34.63 to $35.86 per unit and an estimated forfeiture rate of 17.0%.

The total fair value of restricted unit awards that vested during the year ended December 31, 2008 was $24 thousand. At December 31, 2008, the estimated total unrecognized compensation cost related to nonvested restricted unit awards granted under the TEPPCO 2006 LTIP was $3.7 million. We expect to recognize our share of this cost over a weighted-average period of 2.8 years in accordance with the ASA.

Each recipient of a restricted unit award under the TEPPCO 2006 LTIP is entitled to cash distributions equal to the product of the number of restricted units outstanding for the participant and the cash distribution per unit paid by TEPPCO to its unitholders. Since restricted units are issued securities of TEPPCO, such distributions are reflected as a component of cash distributions to former owners as shown on our Statements of Consolidated Cash Flows. We paid $0.3 million and $0.1 million in cash distributions with respect to restricted units granted under the TEPPCO 2006 LTIP during the years ended December 31, 2008 and 2007, respectively.

UARs and phantom units. At December 31, 2008, there were a total of 95,654 UARs outstanding that had been granted to non-employee directors of TEPPCO GP and 335,723 UARs outstanding that were granted to certain employees of EPCO who worked on behalf of TEPPCO. There were a total of 401,948 UARs outstanding at December 31, 2007. These UAR awards are subject to five year cliff vesting. If the non-employee director or employee resigns prior to vesting, their UAR awards are forfeited. These UAR awards are accounted for similar to liability awards under SFAS 123(R) since they will be settled with cash.

As of December 31, 2008 and 2007, there were a total of 1,647 phantom unit awards outstanding that had been granted to non-employee directors of TEPPCO GP. Each phantom unit will be redeemed in cash the earlier of (i) April 2011 or (ii) when the director is no longer serving on the board of TEPPCO GP. In addition, during the vesting period, each participant is entitled to cash distributions equal to the product of the number of phantom units outstanding for the participant and the cash distribution per unit paid by TEPPCO on its units. Phantom units awarded to non-employee directors are accounted for similar to liability awards.

The TEPPCO 2006 LTIP provides for the award of DERs in tandem with its phantom unit and UAR awards. With respect to DERs granted in connection with phantom units, the participant is entitled to cash distributions equal to the product of the number of phantom units outstanding for the participant and the cash distribution rate paid by TEPPCO to its unitholders. With respect to DERs granted in connection with UARs, the participant is entitled to the product of the number of UARs outstanding for the participant and the difference between the current declared cash distribution rate paid by TEPPCO and the declared cash distribution rate paid by TEPPCO at the time the UAR was granted. Since phantom units and UARs do not represent issued securities, the cash payments with respect to DERs are expensed by TEPPCO as paid. For the years ended December 31, 2008 and 2007, phantom unitholders under the TEPPCO 2006 LTIP received $4 thousand and $2 thousand in cash distributions, respectively.

Note 6. Employee Benefit Plans

Dixie

In 2005, we acquired a controlling ownership interest in Dixie, which resulted in Dixie becoming a consolidated subsidiary of ours. Dixie employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in a defined contribution plan and pension and postretirement benefit plans. Due to the immaterial nature of Dixie's employee benefit plans to our consolidated financial position, results of operations and cash flows, our discussion is limited to the following:

Defined Contribution Plan. Dixie contributed $0.3 million to its company-sponsored defined contribution plan for each of the years ended December 31, 2008 and 2007.

Pension and Postretirement Benefit Plans. Dixie's pension plan is a noncontributory defined benefit plan that provides for the payment of benefits to retirees based on their age at retirement, years of service and average compensation. Dixie's postretirement benefit plan also provides medical and life insurance to retired employees. The medical plan is contributory and the life insurance plan is noncontributory. Dixie employees hired after July 1, 2004 are not eligible for pension and other benefit plans after retirement.

The following table presents Dixie's benefit obligations, fair value of plan assets and funded status at December 31, 2008:

	Pension Plan	Postretirement Plan
Projected benefit obligation	$ 7.7	$ 5.0
Accumulated benefit obligation	5.7	--
Fair value of plan assets	4.0	--
Funded status	(3.7)	(5.0)

Projected benefit obligations and net periodic benefit costs are based on actuarial estimates and assumptions. The weighted-average actuarial assumptions used in determining the projected benefit obligation at December 31, 2008 were as follows: discount rate of 6.4%; rate of compensation increase of 4.0% for both the pension and postretirement plans; and a medical trend rate of 8.5% for 2009 grading to an ultimate trend of 5.0% for 2015 and later years. Dixie's net pension and postretirement benefit costs for 2008 were $0.6 million and $0.4 million, respectively. Dixie's net pension and postretirement benefit costs for 2007 were $1.1 million (including settlement loss of $0.6 million) and $0.4 million, respectively.

Future benefits expected to be paid from Dixie's pension and postretirement plans are as follows for the periods indicated:

	Pension Plan	Postretirement Plan
2009	$ 0.3	$ 0.3
2010	0.3	0.4
2011	0.5	0.4
2012	0.4	0.4
2013	0.8	0.4
2014 through 2017	4.2	2.1
Total	$ 6.5	$ 4.0

Included in accumulated other comprehensive loss on the Supplemental Consolidated Balance Sheets at December 31, 2008 and 2007 are the following amounts that have not been recognized in net periodic pension costs:

	December 31,	
	2008	2007
Unrecognized transition obligation	$ 0.9	$ 1.0
Net of tax	0.5	0.6
Unrecognized prior service cost credit	(1.0)	(1.2)
Net of tax	(0.6)	(0.8)
Unrecognized net actuarial loss	1.3	2.8
Net of tax	0.8	1.7

Terminated Plans - TEPPCO

Prior to April 2006, TEPPCO maintained a Retirement Cash Balance Plan (the "RCBP"), which was a non-contributory, trustee-administered pension plan. In April 2006, a determination letter was received from the Internal Revenue Service providing its approval to terminate the plan.

In 2007 and 2006, we recorded settlement charges of approximately $0.1 million and $3.5 million, respectively, in connection with the plan's termination and distribution of assets to plan participants. At December 31, 2008, all benefit obligations to plan participants have been settled. Net pension benefit costs for the RCBP were $0.2 million for the year ended December 31, 2007.

Note 7. Derivative Instruments, Hedging Activities and Fair Value Measurements

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. We may use derivative instruments (e.g., futures, forwards, swaps, options and other derivative instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the types of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt obligations and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates. See Note 14 for information regarding our consolidated debt obligations.

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

The following table presents gains (losses) recorded in net income attributable to our interest rate risk and commodity risk hedging transactions for the periods indicated. These amounts do not present the corresponding gains (losses) attributable to the underlying hedged items.

	For the Year Ended December 31,		
	2008	2007	2006
Interest Rate Risk Hedging Portfolio:			
Enterprise Products Partners (excluding Duncan Energy Partners):			
Ineffective portion of cash flow hedges	$ (0.1)	$ --	$ --
Reclassification of cash flow hedge amounts from AOCI, net	(0.5)	5.5	4.2
Loss from treasury lock cash flow hedge	(3.6)	--	--
Other gains (losses) from derivative transactions	9.4	(3.7)	3.4
Duncan Energy Partners:			
Ineffective portion of cash flow hedges	--	(0.2)	--
Reclassification of cash flow hedge amounts from AOCI, net	(2.0)	0.4	--
Total hedging gains, net, in consolidated interest expense	$ 3.2	$ 2.0	$ 7.6
Commodity Risk Hedging Portfolio:			
Enterprise Products Partners:			
Reclassification of cash flow hedge amounts from AOCI, net - natural gas marketing activities	$ (30.2)	$ (3.3)	$ (1.3)
Reclassification of cash flow hedge amounts from AOCI, net - crude oil marketing activities	(37.9)	(1.6)	0.2
Reclassification of cash flow hedge amounts from AOCI, net - NGL and petrochemical operations	(28.2)	(4.6)	13.9
Other gains (losses) from derivative transactions	29.4	(20.5)	(2.4)
Total hedging gains (losses), net, in consolidated operating costs and expenses	$ (66.9)	$ (30.0)	$ 10.4

The following table provides additional information regarding derivative assets and derivative liabilities included in our Supplemental Consolidated Balance Sheets at the dates indicated:

	December 31,	
	2008	2007
Current assets:		
Derivative assets:		
Interest rate risk hedging portfolio	$ 7.8	$ 0.2
Commodity risk hedging portfolio	201.5	10.8
Foreign currency risk hedging portfolio	9.3	1.3
Total derivative assets – current	$ 218.6	$ 12.3
Other assets:		
Interest rate risk hedging portfolio	$ 38.9	$ 14.7
Total derivative assets – long-term	$ 38.9	$ 14.7
Current liabilities:		
Derivative liabilities:		
Interest rate risk hedging portfolio	$ 5.9	$ 47.5
Commodity risk hedging portfolio	296.9	48.9
Foreign currency risk hedging portfolio	0.1	--
Total derivative liabilities – current	$ 302.9	$ 96.4
Other liabilities:		
Interest rate risk hedging portfolio	$ 3.9	$ 3.1
Commodity risk hedging portfolio	0.2	--
Total derivative liabilities– long-term	$ 4.1	$ 3.1

The following table presents gains (losses) recorded in other comprehensive income (loss) for cash flow hedges associated with our interest rate risk, commodity risk and foreign currency risk hedging portfolios. These amounts do not present the corresponding gains (losses) attributable to the underlying hedged items.

	For the Year Ended December 31,		
	2008	2007	2006
Interest Rate Risk Hedging Portfolio:			
Enterprise Products Partners (excluding Duncan Energy Partners):			
Gains (losses) on cash flow hedges	$ (47.6)	$ (5.6)	$ 11.0
Reclassification of cash flow hedge amounts to net income, net	0.5	(5.5)	(4.2)
Duncan Energy Partners:			
Losses on cash flow hedges	(8.0)	(3.3)	--
Reclassification of cash flow hedge amounts to net income, net	2.0	(0.3)	--
Total interest rate risk hedging gains (losses), net	(53.1)	(14.7)	6.8
Commodity Risk Hedging Portfolio:			
Enterprise Products Partners:			
Natural gas marketing activities:			
Losses on cash flow hedges	(30.6)	(3.1)	(1.0)
Reclassification of cash flow hedge amounts to net income, net	30.2	3.3	1.3
Crude oil marketing activities:			
Gains (losses) on cash flow hedges	(19.3)	(21.0)	1.0
Reclassification of cash flow hedge amounts to net income, net	37.9	1.6	(0.2)
NGL and petrochemical operations:			
Gains (losses) on cash flow hedges	(120.3)	(22.8)	9.9
Reclassification of cash flow hedge amounts to net income, net	28.2	4.6	(13.9)
Total commodity risk hedging losses, net	(73.9)	(37.4)	(2.9)
Foreign Currency Risk Hedging Portfolio:			
Gains on cash flow hedges	9.3	1.3	--
Total foreign currency risk hedging gains, net	9.3	1.3	--
Total cash flow hedge amounts in other comprehensive income (loss)	$ (117.7)	$ (50.8)	$ 3.9

The following information summarizes the principal elements of our interest rate risk, commodity risk and foreign currency risk hedging portfolios. For amounts recorded in net income and other comprehensive income and on our supplemental balance sheet related to our consolidated hedging activities, please refer to the preceding tables.

Interest Rate Risk Hedging Portfolio

Our interest rate exposure results from variable and fixed rate borrowings under various debt agreements. The following information summarizes significant components of our interest rate risk hedging portfolio:

Fair value hedges – interest rate swaps

We manage a portion of our interest rate exposure by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. At December 31, 2008, we had four interest rate swap agreements outstanding having an aggregate notional value of $400.0 million that were accounted for as fair value hedges. The aggregate fair value of these interest rate swaps at December 31, 2008, was $46.7 million (an asset), with an offsetting increase in the fair value of the underlying debt. There were eleven interest rate swaps outstanding at December 31, 2007 having an aggregate fair value of $12.9 million (an asset). The following table summarizes our interest rate swaps outstanding at December 31, 2008.

Hedged Fixed Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Value
Senior Notes C, 6.375% fixed rate, due Feb. 2013	1	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.015%	$100.0 million
Senior Notes G, 5.60% fixed rate, due Oct. 2014	3	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 5.297%	$300.0 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these interest rate swaps as fair value hedges under SFAS 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in the fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

Cash flow hedges – interest rate swaps (excluding Duncan Energy Partners)

At December 31, 2007, we had interest rate swap agreements outstanding having an aggregate notional value of $200.0 million and a fair value (an asset) of $0.3 million accounted for as cash flow hedges. These swap agreements settled in January 2008, and there are currently no swap agreements outstanding accounted for as cash flow hedges.

Cash flow hedges – treasury locks

We may enter into treasury rate lock transactions ("treasury locks") to hedge U.S. treasury rates related to its anticipated issuances of debt. Each of our treasury lock transactions was designated as a cash flow hedge. Gains or losses on the termination of such instruments are reclassified into net income (as a component of interest expense) using the effective interest method over the estimated term of the underlying fixed-rate debt. At December 31, 2008, we had no treasury lock derivative instruments outstanding. At December 31, 2007, the aggregate notional value of our treasury lock derivative instruments was $1.20 billion, which had a total fair value (a liability) of $44.9 million. We terminated a number of treasury lock derivative instruments during 2008 and 2007. These terminations resulted in realized losses of $92.5 million in 2008 and gains of $48.8 million in 2007.

We expect to reclassify $4.2 million of cumulative net losses from our interest rate risk cash flow hedges into net income (as an increase to interest expense) during 2009.

Cash flow hedges – Duncan Energy Partners' interest rate swaps

At December 31, 2008, Duncan Energy Partners had interest rate swap agreements outstanding having an aggregate notional value of $175.0 million. These swaps were accounted for as cash flow hedges. The purpose of these derivative instruments is to reduce the sensitivity of Duncan Energy Partners' earnings to the variable interest rates charged under its revolving credit facility. The aggregate fair value of these interest rate swaps at December 31, 2008 and 2007 was a liability of $9.8 million and $3.8 million, respectively. Duncan Energy Partners expects to reclassify $6.0 million of cumulative net losses from its interest rate risk cash flow hedges into net income (as an increase to interest expense) during 2009. The following table summarizes Duncan Energy Partners' interest rate swaps outstanding at December 31, 2008.

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
DEP I Revolving Credit Facility, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	1.47% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

As cash flow hedges, any increase or decrease in fair value (to the extent effective) would be recorded in other comprehensive income (loss) and amortized into earnings based on the settlement period hedged. Any ineffectiveness is recorded directly into earnings as an increase in interest expense.

Commodity Risk Hedging Portfolio

Our commodity risk hedging portfolio was impacted by a significant decline in natural gas and crude oil prices during the second half of 2008. As a result of the global recession, commodity prices have continued to be volatile during the first quarter of 2009. We may experience additional losses related to our commodity risk hedging portfolio in 2009.

The prices of natural gas, NGLs, crude oil and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity derivative instruments.

The primary purpose of our commodity risk management activities is to reduce our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL and crude oil production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs, crude oil or certain petrochemical products. From time to time, we inject natural gas into storage and may utilize hedging instruments to lock in the value of its inventory positions. The commodity derivative instruments we utilize are settled in cash.

We have segregated our commodity derivative instruments portfolio between those derivative instruments utilized in connection with our natural gas marketing activities, our crude oil marketing activities and our NGL and petrochemical operations.

A significant number of the derivative instruments in this portfolio hedge the purchase of physical natural gas. If natural gas prices fall below the price stipulated in such derivative instruments, we recognize a liability for the difference; however, if prices partially or fully recover, this liability would be reduced or eliminated, as appropriate. Our restricted cash balance at December 31, 2008 was $203.8 million in order to meet commodity exchange deposit requirements and the negative change in the fair value of our natural gas hedge positions.

Natural gas marketing activities

At December 31, 2008 and 2007, the aggregate fair value of those derivative instruments utilized in connection with our natural gas marketing activities was an asset of $6.5 million and a liability of $0.3

million, respectively. Almost all of the derivative instruments within this portion of the commodity derivative instruments portfolio are accounted for using mark-to-market accounting, with a small number accounted for as cash flow hedges. We did not have any cash flow hedges related to our natural gas marketing activities at December 31, 2008.

Crude oil marketing activities

The fair value of the open positions at December 31, 2008 and 2007 was an asset of $3 thousand and a liability of $18.9 million, respectively. At December 31, 2008, we had no commodity derivative instruments that were accounted for as cash flow hedges. At December 31, 2007, we had a limited number of commodity derivative instruments that were accounted for as cash flow hedges. We have some commodity derivative instruments that do not qualify for hedge accounting. These derivative instruments had a minimal impact on our earnings.

NGL and petrochemical operations

At December 31, 2008 and 2007, the aggregate fair value of those derivative instruments utilized in connection with our NGL and petrochemical operations were liabilities of $102.1 million and $19.0 million, respectively. Almost all of the derivative instruments within this portion of the commodity derivative instruments portfolio are accounted for as cash flow hedges, with a small number accounted for using mark-to-market accounting. We expect to reclassify $114.0 million of cumulative net losses from these cash flow hedges into net income (as an increase in operating costs and expenses) during 2009.

We have employed a program to economically hedge a portion of our earnings from natural gas processing in the Rocky Mountain region. This program consists of (i) the forward sale of a portion of our expected equity NGL production volumes at fixed prices through 2009 and (ii) the purchase, using commodity derivative instruments, of the amount of natural gas expected to be consumed as plant thermal reduction ("PTR") in the production of such equity NGL volumes. The objective of this strategy is to hedge a level of gross margins (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) associated with the forward sales contracts by fixing the cost of natural gas used for PTR, through the use of commodity derivative instruments. At December 31, 2008, this hedging program had hedged future expected gross margins (before plant operating expenses) of $483.9 million on 22.5 million barrels of forecasted NGL forward sales transactions extending through 2009.

Our NGL forward sales contracts are not accounted for as derivative instruments under SFAS 133 since they meet normal purchase and sale exception criteria; therefore, changes in the aggregate economic value of these sales contracts are not reflected in net income and other comprehensive income until the volumes are delivered to customers. On the other hand, the commodity derivative instruments used to purchase the related quantities of PTR (i.e., "PTR hedges") are accounted for as cash flow hedges; therefore, changes in the aggregate fair value of the PTR hedges are presented in other comprehensive income. Once the forecasted NGL forward sales transactions occur, any realized gains and losses on the cash flow hedges would be reclassified into net income in that period.

Prior to actual settlement, if the market price of natural gas is less than the price stipulated in a commodity derivative instrument, we recognize an unrealized loss in other comprehensive loss for the excess of the natural gas price stated in the hedge over the market price. To the extent that we realize such financial losses upon settlement of the instrument, the losses are added to the actual cost we pay for PTR, which would then be based on the lower market price. Conversely, if the market price of natural gas is greater than the price stipulated in such hedges, we recognize an unrealized gain in other comprehensive income for the excess of the market price over the natural gas price stated in the PTR hedge. If realized, the gains on the derivative instrument would serve to reduce the actual cost paid for PTR, which would then be based on the higher market price. The net effect of these hedging relationships is that our total cost of natural gas used for PTR approximates the amount it originally hedged under this program.

Foreign Currency Hedging Portfolio

We are exposed to foreign currency exchange rate risk primarily through a Canadian NGL marketing subsidiary. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate. Mark-to-market accounting is utilized for these contracts, which typically have a duration of one month. For the year ended December 31, 2008, we recorded minimal gains from these derivative instruments.

In addition, we are exposed to foreign currency exchange rate risk through our Japanese Yen Term Loan Agreement (“Yen Term Loan”) that EPO entered into in November 2008. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Japanese yen. We hedged this risk by entering into a foreign exchange purchase contract to fix the exchange rate. This purchase contract was designated as a cash flow hedge. At December 31, 2008, the fair value of this contract was $9.3 million. This contract will be settled in March 2009 upon repayment of the Yen Term Loan. Total interest expense under this loan agreement was $4.0 million, of which $1.7 million is the expected foreign currency loss, which will be recorded as interest expense.

Adoption of SFAS 157 - Fair Value Measurements

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. We adopted the provisions of SFAS 157 that apply to nonfinancial assets and liabilities on January 1, 2009. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date.

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

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

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

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

§ Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally-developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Level 3 generally includes specialized or unique derivative instruments that are tailored to meet a customer's specific needs. At December 31, 2008, our Level 3 financial assets consisted of ethane based contracts with a range of two to twelve months in term. This classification is primarily due to our reliance on broker quotes for this product due to the forward ethane markets being less than highly active.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities measured on a recurring basis at December 31, 2008. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Level 1	Level 2	Level 3	Total
Financial assets:				
Commodity derivative instruments	$ 4.0	$ 164.7	$ 32.8	$ 201.5
Foreign currency derivative instruments	--	9.3	--	9.3
Interest rate derivative instruments	--	46.7	--	46.7
Total	$ 4.0	$ 220.7	$ 32.8	$ 257.5
Financial liabilities:				
Commodity derivative l instruments	$ 7.1	$ 289.6	$ 0.4	$ 297.1
Foreign currency derivative instruments	--	0.1	--	0.1
Interest rate derivative instruments	--	9.8	--	9.8
Total	$ 7.1	$ 299.5	$ 0.4	$ 307.0
Net financial assets, Level 3			$ 32.4	

Fair values associated with our interest rate, commodity and foreign currency derivative instrument portfolios were developed using available market information and appropriate valuation techniques in accordance with SFAS 157.

The following table sets forth a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities during the year ended December 31, 2008:

Balance, January 1, 2008	$ (5.0)
Total gains (losses) included in:	
Net income (1)	(34.6)
Other comprehensive loss	37.2
Purchases, issuances, settlements	34.8
Balance, December 31, 2008	$ 32.4

(1) There were unrealized gains of $0.2 million included in net income for the year ended December 31, 2008.

Fair Value Information

Cash and cash equivalents, accounts receivable, accounts payable and accrued expenses are carried at amounts which reasonably approximate their fair values due to their short-term nature. The estimated fair values of our fixed rate debt are based on quoted market prices for such debt or debt of similar terms and maturities. The carrying amounts of our variable rate debt obligations reasonably approximate their fair values due to their variable interest rates. The fair values associated with our interest rate and commodity hedging portfolios were developed using available market information and appropriate valuation techniques. The following table presents the estimated fair values of our derivative instruments at the dates indicated:

	December 31, 2008		December 31, 2007	
Derivative Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents, including restricted cash	$ 265.5	$ 265.5	$ 104.4	$ 104.4
Accounts receivable	2,063.8	2,063.8	3,403.5	3,403.5
Commodity derivative instruments (1)	201.5	201.5	10.8	10.8
Foreign currency hedging derivative instruments (2)	9.3	9.3	1.3	1.3
Interest rate hedging derivative instruments (3)	46.7	46.7	14.9	14.9
Financial liabilities:				
Accounts payable and accrued expenses	2,506.0	2,506.0	4,216.3	4,216.3
Fixed-rate debt (principal amount) (4)	9,704.3	8,192.2	7,259.0	7,238.7
Variable-rate debt	1,858.5	1,858.5	1,482.5	1,482.5
Commodity derivative instruments (1)	297.1	297.1	48.9	48.9
Foreign currency hedging derivative instruments (2)	0.1	0.1	--	--
Interest rate hedging derivative instruments (3)	9.8	9.8	50.6	50.6

(1) Represent commodity derivative instrument transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.
(2) Relates to the hedging of our exposure to fluctuations in the Canadian dollar and Japanese yen.
(3) Represent interest rate hedging derivative instrument transactions that have not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.
(4) Due to the distress in the capital markets following the collapse of several major financial entities and uncertainty in the credit markets during 2008, corporate debt securities were trading at significant discounts.

Note 8. Cumulative Effect of Change in Accounting Principle

SFAS 123(R) requires us to recognize compensation expense related to equity awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying common units on the date of grant. The fair value of other equity awards is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of an equity award is amortized to earnings on a straight-line basis over the requisite service or vesting period for equity awards. Compensation for liability-classified awards is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability awards will be cash settled upon vesting.

Upon adoption of SFAS 123(R), we recognized, as a benefit, the cumulative effect of a change in accounting principle of $1.5 million based on the SFAS 123(R) requirement to recognize compensation expense based upon the grant date fair value of equity awards and the application of an estimated forfeiture rate to unvested awards. See Note 5 for additional information regarding our accounting for equity awards.

The following table shows unaudited pro forma net income for the year ended December 31, 2006, assuming the accounting change noted above was applied retroactively to January 1, 2006.

Pro Forma income statement amounts:		
Historical net income attributable to Enterprise Products Partners L.P.	$	601.1
Adjustments to derive pro forma net income attributable to Enterprise Products Partners L.P.:		
Effect of implementation of SFAS 123(R):		
Remove cumulative effect of change in accounting principle recorded in January 2006		(1.5)
Pro forma net income attributable to Enterprise Products Partners L.P.		599.6
EPGP interest (1)		(103.0)
Pro forma net income allocated to limited partners	$	496.6
Pro forma per unit data (basic):		
Historical units outstanding		414.4
Per unit data:		
As reported	$	1.20
Pro forma	$	1.20
Pro forma per unit data (diluted):		
Historical units outstanding		414.7
Per unit data:		
As reported	$	1.20
Pro forma	$	1.20

(1) Includes provisions of EITF 07-4 (see Note 19).

Note 9. Inventories

Our inventory amounts were as follows at the dates indicated:

	December 31,			
	2008		2007	
Working inventory (1)	$	211.9	$	397.5
Forward sales inventory (2)		193.1		28.2
Total inventory	$	405.0	$	425.7

(1) Working inventory is comprised of inventories of natural gas, crude oil, refined products, lubrication oils, NGLs and certain petrochemical products that are either available-for-sale or used in the provision for services.
(2) Forward sales inventory consists of identified natural gas, crude oil and NGL volumes dedicated to the fulfillment of forward sales contracts.

Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection costs, demurrage charges and other related costs. We value our inventories at the lower of average cost or market.

Operating costs and expenses, as presented on our Supplemental Statements of Consolidated Operations, include cost of sales amounts related to the sale of inventories. Our costs of sales were $31.20 billion, $23.49 billion and $20.71 billion for the years ended December 31, 2008, 2007 and 2006, respectively.

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to actually purchasing volumes for cash from third parties, see Note 4), these volumes are valued at market-related prices during the month in which they are acquired. We capitalize as a component of inventory those ancillary costs (e.g. freight-in and other handling and processing charges) incurred in connection with volumes obtained through such contracts.

Due to fluctuating commodity prices, we recognize lower of cost or market ("LCM") adjustments when the carrying value of our inventories exceed their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized and generally affect our segment operating results in the following manner:

§ Write-downs of NGL inventories associated with our NGL marketing activities are recorded within our NGL Pipelines & Services business segment;

§ Write-downs of natural gas inventories are recorded as a cost of our natural gas pipeline operations within our Onshore Natural Gas Pipelines & Services business segment;

§ Write-downs of crude oil inventories are recorded as a cost of our crude oil operations within our Onshore Crude Oil Pipelines & Services; and

§ Write-downs of petrochemical and related inventories, including refined products, associated with our Petrochemical & Refined Products business segment are recorded as a cost of our petrochemical marketing activities, refined products businesses or octane enhancement production business, as applicable.

For the years ended December 31, 2008, 2007 and 2006, we recognized LCM adjustments of approximately $63.0 million, $14.1 million and $20.3 million, respectively. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 7 for a description of our commodity hedging activities.

Note 10. Property, Plant and Equipment

Our property, plant and equipment values and accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	December 31, 2008	December 31, 2007
Plants and pipelines (1)	3-40 (6)	$ 15,266.7	$ 13,395.2
Underground and other storage facilities (2)	5-40 (7)	1,203.9	981.6
Platforms and facilities (3)	20-31	634.8	637.8
Transportation equipment (4)	3-10	50.9	41.0
Marine vessels (5)	20-30	453.0	--
Land		254.5	220.5
Construction in progress		2,015.4	1,588.3
Total		19,879.2	16,864.4
Less accumulated depreciation		3,146.4	2,555.3
Property, plant and equipment, net		$ 16,732.8	$ 14,309.1

(1) Plants and pipelines include processing plants; NGL, petrochemical, crude oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.
(2) Underground and other storage facilities include underground product storage caverns; above ground storage tanks; water wells; and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets.
(4) Transportation equipment includes vehicles and similar assets used in our operations.
(5) See Note 12 for additional information regarding the acquisition of marine services businesses in February 2008.
(6) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines and related equipment, 5-40 years; terminal facilities, 10-35 years; delivery facilities, 20-40 years; office furniture and equipment, 3-20 years; buildings, 20-40 years; and laboratory and shop equipment, 5-35 years.
(7) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For the Year Ended December 31, 2008	2007	2006
Depreciation expense (1)	$ 595.9	$ 515.7	$ 433.7
Capitalized interest (2)	90.7	86.5	66.4

(1) Depreciation expense is a component of costs and expenses as presented in our Supplemental Statements of Consolidated Operations.
(2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.

We reviewed assumptions underlying the estimated remaining useful lives of certain of our assets during the first quarter of 2008. As a result of our review, effective January 1, 2008, we revised the remaining useful lives of these assets, most notably the assets that constitute our Texas Intrastate System. This revision increased the remaining useful life of such assets to incorporate recent data showing that proved natural gas reserves supporting throughput and processing volumes for these assets have changed since our original determination made in September 2004. These revisions will prospectively reduce our depreciation expense on assets having carrying values totaling $2.72 billion as of January 1, 2008. On average, we extended the life of these assets by 3.1 years. As a result of this change in estimate, depreciation expense included in operating income and net income for the year ended December 31, 2008 decreased by approximately $20.0 million, which increased our basic and diluted earnings per unit by $0.04 from what it would have been absent the change.

In August 2008, we, together with Oiltanking Holding Americas, Inc. (“Oiltanking”), announced the formation of the Texas Offshore Port System (or “TOPS”), which was a joint venture to design, construct, operate and own a Texas offshore crude oil port and related pipeline and storage system that would facilitate delivery of waterborne crude oil cargoes to refining centers located along the upper Texas

Gulf Coast. We owned a two-thirds interest in TOPS, with Oiltanking owning the remaining one-third interest. Construction in progress amounts at December 31, 2008 included $90.6 million attributable to TOPS, which is a consolidated subsidiary of ours. See Note 25 for subsequent event information regarding our dissociation from TOPS in April 2009.

Asset retirement obligations

We have recorded AROs related to legal requirements to perform retirement activities as specified in contractual arrangements and/or governmental regulations. In general, our AROs primarily result from (i) right-of-way agreements associated with our pipeline operations, (ii) leases of plant sites and (iii) regulatory requirements triggered by the abandonment or retirement of certain underground storage assets and offshore facilities. In addition, our AROs may result from the renovation or demolition of certain assets containing hazardous substances such as asbestos.

The following table presents information regarding our AROs since December 31, 2006:

ARO liability balance, December 31, 2006	$	25.8
Liabilities incurred		1.8
Liabilities settled		(5.1)
Revisions in estimated cash flows		15.6
Accretion expense		4.1
ARO liability balance, December 31, 2007		42.2
Liabilities incurred		1.1
Liabilities settled		(8.2)
Revisions in estimated cash flows		4.7
Accretion expense		2.4
ARO liability balance, December 31, 2008	$	42.2

Property, plant and equipment at December 31, 2008 and 2007 includes $11.7 million and $11.3 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. We estimate that accretion expense will approximate $2.3 million for 2009, $2.4 million for 2010, $2.6 million for 2011, $2.9 million for 2012 and $3.1 million for 2013.

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2008 and 2007 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our supplemental financial statements.

Note 11. Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. Our investments in unconsolidated affiliates are grouped according to the business segment to which they relate. See Note 16 for a general discussion of our business segments. The following table shows our investments in unconsolidated affiliates at the dates indicated:

	Ownership Percentage at December 31, 2008	December 31, 2008	December 31, 2007
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C. (“VESCO”)	13.1%	$ 37.7	$ 40.1
K/D/S Promix, L.L.C. (“Promix”)	50%	46.4	51.5
Baton Rouge Fractionators LLC (“BRF”)	32.2%	24.2	25.4
Skelly-Belvieu Pipeline Company, L.L.C. (“Skelly-Belvieu”) (1)	49%	36.0	--
Onshore Natural Gas Pipelines & Services:			
Evangeline (2)	49.5%	4.5	3.5
White River Hub, LLC (“White River Hub”) (3)	50%	21.4	--
Onshore Crude Oil Pipelines & Services			
Seaway Crude Pipeline Company (“Seaway”)	50%	186.2	184.8
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C. (“Poseidon”)	36%	60.2	58.4
Cameron Highway Oil Pipeline Company (“Cameron Highway”) (4)	50%	250.9	256.6
Deepwater Gateway, L.L.C. (“Deepwater Gateway”)	50%	104.8	111.2
Neptune	25.7%	52.7	55.5
Nemo (5)	33.9%	0.4	2.9
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC (“BRPC”)	30%	12.6	13.3
La Porte (6)	50%	3.9	4.1
Centennial Pipeline LLC (“Centennial”)	50%	69.7	77.9
Other	25%	0.3	0.4
Total		$ 911.9	$ 885.6

(1) In December 2008, we acquired a 49% ownership interest in Skelly-Belvieu.
(2) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(3) In February 2008, we acquired a 50% ownership interest in White River Hub.
(4) During the year ended December 31, 2007, we contributed $216.5 million to Cameron Highway to fund our portion of the repayment of Cameron Highway’s debt.
(5) The December 31, 2007 amount includes a $7.0 million non-cash impairment charge attributable to our investment in Nemo.
(6) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in and advances to unconsolidated affiliates. At December 31, 2008 and 2007, our investments in Promix, Skelly-Belvieu, La Porte, Neptune, Poseidon, Cameron Highway, Seaway and Centennial included excess cost amounts totaling $75.6 million and $69.5 million, respectively, all of which were attributable to the fair value of the underlying tangible assets of these entities exceeding their book carrying values at the time of our acquisition of interests in these entities. To the extent that we attribute all or a portion of an excess cost amount to higher fair values, we amortize such excess cost as a reduction in equity earnings in a manner similar to depreciation. To the extent we attribute an excess cost amount to goodwill, we do not amortize this amount but it is subject to evaluation for impairment. Amortization of such excess cost amounts was $6.8 million, $7.9 million and $6.4 million for the years ended December 31, 2008, 2007 and 2006, respectively.

The following table presents our equity in earnings of unconsolidated affiliates for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services:			
VESCO	$ (1.6)	$ 3.5	$ 1.7
Promix	2.0	0.5	1.4
BRF	1.0	2.0	2.6
MB Storage (1)	--	1.1	9.1
Onshore Natural Gas Pipelines & Services:			
Evangeline	0.9	0.2	1.0
Coyote Gas Treating, LLC (“Coyote”)	--	--	1.7
White River Hub	0.7	--	--
Onshore Crude Oil Pipelines & Services			
Seaway	11.7	2.6	11.9
Offshore Pipelines & Services:			
Poseidon	6.9	10.0	11.3
Cameron Highway	16.4	(11.2)	(11.1)
Deepwater Gateway	17.1	20.6	18.4
Neptune (2)	(5.7)	(0.8)	(8.3)
Nemo (3)	(1.0)	(6.0)	1.5
Petrochemical & Refined Products Services:			
BRPC	1.9	2.3	1.9
La Porte	(0.8)	(0.8)	(0.8)
Centennial	(14.7)	(13.5)	(17.1)
Other	0.1	--	--
Total	$ 34.9	$ 10.5	$ 25.2

(1) Refers to ownership interests in Mont Belvieu Storage Partners, L.P. and Mont Belvieu Venture, LLC, collectively. We disposed of this investment on March 1, 2007.
(2) Equity in earnings from Neptune for 2006 include a $7.4 million non-cash impairment charge.
(3) Equity in earnings from Nemo for 2007 include a $7.0 million non-cash impairment charge.

NGL Pipelines & Services

At December 31, 2008, our NGL Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

VESCO. We own a 13.1% interest in VESCO, which owns a natural gas processing facility and related assets located in south Louisiana.

Promix. We own a 50% interest in Promix, which owns an NGL fractionation facility and related storage and pipeline assets located in south Louisiana.

BRF. We own an approximate 32.2% interest in BRF, which owns an NGL fractionation facility located in south Louisiana.

Skelly-Belvieu. In December 2008, we acquired a 49% interest in Skelly-Belvieu for $36.0 million. Skelly-Belvieu owns a 570-mile pipeline that transports mixed NGLs to markets in southeast Texas.

MB Storage. During 2007, we sold our 49.5% ownership interest in Mont Belvieu Storage Partners, L.P. (“MB Storage”) and our 50% ownership interest in Mont Belvieu Venture, LLC (the general partner of MB Storage) to Louis Dreyfus Energy Services L.P. for approximately $156.0 million in cash. We recognized a gain of approximately $60.0 million related to the sale of these equity interests, which is included in “Other, net” in our Supplemental Statement of Consolidated Operations for the year ended December 31, 2007. The sale of MB Storage was required by the U.S. Federal Trade Commission (“FTC”) in connection with ending its investigation into the acquisition of TEPPCO GP by private company affiliates of EPCO in February 2005.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31, 2008	At December 31, 2007
BALANCE SHEET DATA:		
Current assets	$ 64.1	$ 112.3
Property, plant and equipment, net	368.1	270.6
Other assets	2.0	11.7
Total assets	$ 434.2	$ 394.6
Current liabilities	$ 50.2	$ 75.3
Other liabilities	24.3	9.1
Combined equity	359.7	310.2
Total liabilities and combined equity	$ 434.2	$ 394.6

	For the Year Ended December 31, 2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 271.3	$ 227.4	$ 225.1
Operating income (loss)	20.5	42.5	(12.3)
Net income (loss)	20.9	28.0	(10.4)

Onshore Natural Gas Pipelines & Services

At December 31, 2008, our Onshore Natural Gas Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Evangeline. We own an approximate 49.5% aggregate interest in Evangeline, which owns a natural gas pipeline located in south Louisiana. A subsidiary of Acadian Gas, LLC owns the Evangeline interests, which were contributed to Duncan Energy Partners in February 2007 in connection with its initial public offering (see Note 17).

Coyote. We owned a 50% interest in Coyote during 2005, which owns a natural gas treating facility located in the San Juan Basin of southwestern Colorado. During 2006, we sold our interest in Coyote and recorded a gain on the sale of $3.3 million.

White River Hub. We own a 50% interest in White River Hub, which owns a natural gas hub located in northwest Colorado. The hub was completed in December 2008.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31, 2008	At December 31, 2007
BALANCE SHEET DATA:		
Current assets	$ 43.6	$ 28.5
Property, plant and equipment, net	60.2	5.2
Other assets	17.5	21.2
Total assets	$ 121.3	$ 54.9
Current liabilities	$ 33.9	$ 21.4
Other liabilities	21.5	24.7
Combined equity	65.9	8.8
Total liabilities and combined equity	$ 121.3	$ 54.9

	For the Year Ended December 31, 2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 372.5	$ 272.9	$ 292.1
Operating income	7.8	6.3	11.6
Net income	3.1	0.4	5.3

Onshore Crude Oil Pipelines & Services

At December 31, 2008, our Onshore Crude Oil Pipelines & Services segment included the following unconsolidated affiliate accounted for using the equity method:

Seaway. We own a 50% interest in Seaway, which owns a pipeline that transports crude oil from a marine terminal located in Freeport, Texas, to Cushing, Oklahoma, and from a marine terminal located in Texas City, Texas, to refineries in the Texas City and Houston, Texas areas.

The balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliate is summarized below.

	At December 31, 2008	At December 31, 2007
BALANCE SHEET DATA:		
Current assets	$ 31.3	$ 16.5
Property, plant and equipment, net	248.0	251.6
Total assets	$ 279.3	$ 268.1
Current liabilities	$ 6.1	$ 6.5
Equity	273.2	261.6
Total liabilities and equity	$ 279.3	$ 268.1

	For the Year Ended December 31, 2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 93.9	$ 67.3	$ 87.3
Operating income	45.9	21.3	34.2
Net income	46.1	21.6	34.6

Offshore Pipelines & Services

At December 31, 2008, our Offshore Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Poseidon. We own a 36% interest in Poseidon, which owns a crude oil pipeline that gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana.

Cameron Highway. We own a 50% interest in Cameron Highway, which owns a crude oil pipeline that gathers production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas.

Cameron Highway repaid its $365.0 million Series A notes and $50.0 million Series B notes in 2007 using cash contributions from its partners. We funded our 50% share of the capital contributions using borrowings under EPO's Multi-Year Revolving Credit Facility. Cameron Highway incurred a $14.1 million make-whole premium in connection with the repayment of its Series A notes.

Deepwater Gateway. We own a 50% interest in Deepwater Gateway, which owns the Marco Polo platform located in the Gulf of Mexico. The Marco Polo platform processes crude oil and natural gas production from the Marco Polo, K2, K2 North and Genghis Khan fields located in the South Green Canyon area of the Gulf of Mexico.

Neptune. We own a 25.7% interest in Neptune, which owns Manta Ray Offshore Gathering System ("Manta Ray") and Nautilus Pipeline System ("Nautilus"), which are natural gas pipelines located in the Gulf of Mexico.

Nemo. We own a 33.9% interest in Nemo, which owns the Nemo Gathering System, which is a natural gas pipeline located in the Gulf of Mexico.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31, 2008	At December 31, 2007
BALANCE SHEET DATA:		
Current assets	$ 85.3	$ 46.8
Property, plant and equipment, net	1,093.9	1,122.1
Other assets	3.6	4.3
Total assets	$ 1,182.8	$ 1,173.2
Current liabilities	$ 53.3	$ 19.7
Other liabilities	116.7	96.8
Combined equity	1,012.8	1,056.7
Total liabilities and combined equity	$ 1,182.8	$ 1,173.2

	For the Year Ended December 31, 2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 163.9	$ 156.8	$ 154.0
Operating income	69.1	85.6	72.0
Net income	65.7	53.6	42.7

Neptune owns Manta Ray and Nautilus. Manta Ray gathers natural gas originating from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico to numerous downstream pipelines, including the Nautilus pipeline. Nautilus connects our Manta Ray pipeline to our Neptune natural gas processing plant located in south Louisiana. Due to a recent decrease in throughput volumes on the Manta Ray and Nautilus pipelines, we evaluated our 25.7% investment in Neptune for impairment during the third quarter of 2006. The decrease in throughput volumes is primarily due to underperformance of certain fields, natural depletion and hurricane-related delays in starting new production. These factors contributed to significant delays in throughput volumes Neptune expects to receive. As a result, Neptune has experienced operating losses in recent periods.

Our review of Neptune's estimated cash flows during the third quarter of 2006 indicated that the carrying value of our investment exceeded its fair value, which resulted in a non-cash impairment charge of $7.4 million. This loss is recorded as a component of "Equity in income of unconsolidated affiliates" in our Supplemental Statement of Consolidated Operations for the year ended December 31, 2006.

Nemo was formed in 1999 to construct, own and operate the Nemo Gathering System, a 24-mile natural gas gathering system in the Gulf of Mexico offshore Louisiana. The Nemo Gathering System, which began operations in 2001, gathers natural gas from certain developments in the Green Canyon area of the Gulf of Mexico to a pipeline interconnect with the Manta Ray Gathering System. Due to a recent decrease in throughput volumes on the Nemo Gathering System, we evaluated our 33.9% investment in Nemo for impairment during the second quarter of 2007. The decrease in throughput volumes is primarily due to underperformance of certain fields and natural depletion.

Our review of Nemo's estimated future cash flows during the second quarter of 2007 indicated that the carrying value of our investment exceeded its fair value, which resulted in a non-cash impairment charge of $7.0 million. This loss is recorded as a component of "Equity in income of unconsolidated affiliates" in our Supplemental Statement of Consolidated Operations for the year ended December 31, 2007. After recording this impairment charge, the carrying value of our investment in Nemo at December 31, 2007 was $2.9 million.

Our investments in Neptune and Nemo were written down to fair value, which management estimated using recognized business valuation techniques. The fair value analysis is based upon management's expectation of future cash flows, which incorporates certain industry information and assumptions made by management. For example, the individual reviews of Neptune and Nemo included management estimates regarding natural gas reserves of producers served by both Neptune and Nemo, respectively. If the assumptions underlying our fair value analysis change and expected cash flows are reduced, additional impairment charges may result.

Petrochemical & Refined Products Services

At December 31, 2008, our Petrochemical & Refined Products Services segment included the following unconsolidated affiliates accounted for using the equity method:

BRPC. We own a 30% interest in BRPC, which owns a propylene fractionation facility located in south Louisiana.

La Porte. We own an aggregate 50% interest in La Porte, which owns a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas.

Centennial. We own a 50% interest in Centennial, which owns an interstate refined petroleum products pipeline extending from the upper Texas Gulf Coast to central Illinois. Prior to April 2002, our refined products pipeline system was bottlenecked between Beaumont, Texas and El Dorado, Arkansas, which limited our ability to transport refined products and NGLs during peak periods. When the Centennial pipeline commenced operations in 2002, it effectively looped our refined products pipeline system, thus providing incremental transportation capacity into Mid-continent markets.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31, 2008	At December 31, 2007
BALANCE SHEET DATA:		
Current assets	$ 16.5	$ 24.1
Property, plant and equipment, net	283.1	296.2
Total assets	$ 299.6	$ 320.3
Current liabilities	$ 22.4	$ 24.8
Other liabilities	120.3	130.3
Combined equity	156.9	165.2
Total liabilities and combined equity	$ 299.6	$ 320.3

	For the Year Ended December 31, 2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 60.1	$ 69.7	$ 57.3
Operating income	11.0	17.7	0.4
Net income	0.3	6.9	(11.0)

Note 12. Business Combinations

The following table presents our cash used for business combinations for the periods indicated:

	For Year Ended December 31, 2008	2007	2006
Great Divide Gathering System acquisition	$ 125.2	$ --	$ --
Encinal acquisition	--	0.1	145.2
Piceance Creek acquisition	--	0.4	100.0
South Monco acquisition	--	35.0	--
Canadian Enterprise Gas Products, Ltd. acquisition	--	--	17.7
Cenac acquisition	258.1	--	--
Horizon acquisition	87.6	--	--
Terminal assets purchased from New York LP Gas Storage, Inc.	--	--	9.9
Refined products terminal purchased from Mississippi Terminal and Marketing Inc.	--	--	5.8
Additional ownership interests in Dixie	57.1	0.4	12.9
Additional ownership interests in Tri-States and Belle Rose	19.9	--	--
Other business combinations	5.5	--	0.7
Total	$ 553.4	$ 35.9	$ 292.2

The following information highlights aspects of certain transactions noted in the preceding table:

2008 Transactions

Our expenditures for business combinations during the year ended December 31, 2008 were $553.4 million and primarily reflect the acquisitions described below.

On a pro forma consolidated basis, our revenues, costs and expenses, operating income, net income attributable to Enterprise Products Partners L.P. and earnings per unit amounts would not have differed materially from those we actually reported for 2008, 2007 and 2006 due to the immaterial nature of our 2008 business combination transactions.

Great Divide Gathering System Acquisition. In December 2008, one of our subsidiaries, Enterprise Gas Processing, LLC, purchased a 100% membership interest in Great Divide Gathering, LLC ("Great Divide") for cash consideration of $125.2 million. Great Divide was wholly owned by EnCana Oil & Gas ("EnCana").

The assets of Great Divide consist of a 31-mile natural gas gathering system, the Great Divide Gathering System, located in the Piceance Basin of northwestern Colorado. The Great Divide Gathering System extends from the southern portion of the Piceance Basin, including production from EnCana's Mamm Creek field, to a pipeline interconnection with our Piceance Basin Gathering System. Volumes of natural gas originating on the Great Divide Gathering System are transported through our Piceance Creek Gathering System to our 1.4 Bcf/d Meeker natural gas treating and processing complex. A significant portion of these volumes are produced by EnCana, one of the largest natural gas producers in the region, and are dedicated the Great Divide and Piceance Creek Gathering Systems for the life of the associated lease holdings.

Tri-States and Belle Rose Acquisitions. In October 2008, we acquired additional 16.7% membership interests in both Tri-States NGL Pipeline, L.L.C. ("Tri-States") and Belle Rose NGL Pipeline, L.L.C. ("Belle Rose") for total cash consideration of $19.9 million. As a result of this transaction, our ownership interest in Tri-States increased to 83.3%. We now own 100% of the membership interests in Belle Rose.

Tri-States owns a 194-mile NGL pipeline located along the Mississippi, Alabama and Louisiana Gulf Coast. Belle Rose owns a 48-mile NGL pipeline located in Louisiana. These systems, in conjunction with the Wilprise pipeline, transport mixed NGLs to the BRF, Norco and Promix NGL fractionators located in south Louisiana.

Acquisition of Remaining Interest in Dixie. In August 2008, we acquired the remaining 25.8% ownership interests in Dixie for cash consideration of $57.1 million. As a result of this transaction, we own 100% of Dixie, which owns a 1,371-mile pipeline system that delivers NGLs (primarily propane and other chemical feedstock) to customers along the U.S. Gulf Coast and southeastern United States.

Cenac and Horizon Acquisitions. In February 2008, TEPPCO entered the marine transportation business for refined products, crude oil and condensate through the purchase of assets from Cenac Towing Co., Inc., Cenac Offshore, L.L.C., and Mr. Arlen B. Cenac, Jr. (collectively "Cenac"). The aggregate value of total consideration TEPPCO paid or issued to complete this business combination was $444.7 million, which consisted of $258.1 million in cash and approximately 4.9 million newly issued TEPPCO units. Additionally, TEPPCO assumed approximately $63.2 million of Cenac's debt in the transaction. TEPPCO acquired 42 tow boats, 89 tank barges and the economic benefit of certain related commercial agreements. This business serves refineries and storage terminals along the Mississippi, Illinois and Ohio rivers and the Intracoastal Waterway between Texas and Florida. These assets also gather crude oil from production facilities and platforms along the U.S. Gulf Coast. TEPPCO used its Short-Term Credit Facility to finance the cash portion of the acquisition price and to repay the $63.2 million of debt assumed in this transaction.

Also in February 2008, TEPPCO purchased related marine assets from Horizon Maritime, L.L.C. ("Horizon"), a privately held Houston-based company and an affiliate of Mr. Cenac, for $80.8 million in cash. In this transaction, TEPPCO acquired 7 tow boats, 17 tank barges, rights to 2 tow boats under construction and the economic benefit of certain related commercial agreements. In April 2008, TEPPCO paid an additional $3.0 million to Horizon pursuant to the purchase agreement upon delivery of one of the tow boats under construction, and in June 2008, TEPPCO paid an additional $3.8 million upon delivery of the second tow boat. These vessels transport asphalt, heavy fuel oil and other heated oil products to storage facilities and refineries along the Mississippi, Illinois and Ohio Rivers and the Intracoastal Waterway. TEPPCO used its Short-Term Credit Facility to finance this acquisition.

The results of operations related to these assets are included in our Supplemental Condensed Statements of Consolidated Operations beginning at the date of acquisition.

Purchase Price Allocations. We accounted for our business combinations completed during 2008 using the purchase method of accounting and, accordingly, such costs have been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis.

	Cenac Acquisition	Horizon Acquisition	Great Divide	Dixie	Other (1)	Total
Assets acquired in business combination:						
Current assets	$ --	$ --	$ --	$ 4.0	$ 2.6	$ 6.6
Property, plant and equipment, net	362.9	72.2	70.6	33.7	10.1	549.5
Intangible assets	63.5	6.5	9.8	--	12.7	92.5
Other assets	--	--	--	0.4	--	0.4
Total assets acquired	426.4	78.7	80.4	38.1	25.4	649.0
Liabilities assumed in business combination:						
Current liabilities	--	--	--	(2.6)	(0.6)	(3.2)
Long-term debt	--	--	--	(2.6)	--	(2.6)
Other long-term liabilities	(63.2)	--	(0.1)	(46.2)	--	(109.5)
Total liabilities assumed	(63.2)	--	(0.1)	(51.4)	(0.6)	(115.3)
Total assets acquired plus liabilities assumed	363.2	78.7	80.3	(13.3)	24.8	533.7
Fair value of 4,854,899 TEPPCO units	186.6	--	--	--	--	186.6
Total cash used for business combinations	258.1	87.6	125.2	57.1	25.4	553.4
Goodwill	$ 81.5	$ 8.9	$ 44.9	$ 70.4	$ 0.6	$ 206.3

(1) Primarily represents (i) non-cash reclassification adjustments to December 2007 preliminary fair value estimates for assets acquired in the South Monco natural gas pipeline acquisition, (ii) the purchase of lubrication and other fuel assets in August 2008 and (iii) the purchase of additional interests in Tri-States and Belle Rose in October 2008.

As a result of our 100% ownership interest in Dixie, we used push-down accounting to record this business combination. In doing so, a temporary tax difference was created between the assets and liabilities of Dixie for financial reporting and tax purposes. Dixie recorded a deferred income tax liability of $45.1 million attributable to the temporary tax difference.

2007 Transactions

On a pro forma consolidated basis, our revenues, costs and expenses, operating income, net income attributable to Enterprise Products Partners L.P. and earnings per unit amounts would not have differed materially from those we actually reported for 2007 and 2006 due to the immaterial nature of our 2007 business combination transactions.

Our expenditures for business combinations during the year ended December 31, 2007 were $35.9 million, which primarily reflect the $35.0 million we spent to acquire South Monco in December 2007. This business includes approximately 128 miles of natural gas pipelines located in southeast Texas. The remaining business combination related amounts for 2007 consist of purchase price adjustments to prior period transactions.

We accounted for our 2007 business combinations using the purchase method of accounting and, accordingly, such costs have been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis.

2006 Transactions

Our expenditures for business combinations during the year ended December 31, 2006 were $292.2 million and primarily reflect the Encinal and Piceance Creek acquisitions described below.

Encinal Acquisition. In July 2006, we acquired the Encinal and Canales natural gas gathering systems and related gathering and processing contracts that comprised the South Texas natural gas transportation and processing business of an affiliate of Lewis Energy Group, L.P. ("Lewis"). The aggregate value of total consideration we paid or issued to complete this business combination (referred to as the "Encinal acquisition") was $326.3 million, which consisted of $145.2 million in cash and 7,115,844 of our common units.

The Encinal and Canales gathering systems are located in South Texas and are connected to over 1,450 natural gas wells producing from the Olmos and Wilcox formations. The Encinal system consists of 449 miles of pipeline, which is comprised of 277 miles of pipeline we acquired from Lewis in this transaction and 172 miles of pipeline that we own and had previously leased to Lewis. The Canales gathering system is comprised of 32 miles of pipeline. Currently, natural gas volumes gathered by the Encinal and Canales systems are transported by our existing Texas Intrastate System and are processed by our South Texas natural gas processing plants.

The Encinal and Canales gathering systems will be supported by a life of reserves gathering and processing dedication by Lewis related to its natural gas production from the Olmos formation. In addition, we entered into a 10-year agreement with Lewis for the transportation of natural gas treated at its proposed Big Reef facility. This facility will treat natural gas from the southern portion of the Edwards Trend in South Texas. We also entered into a 10-year agreement with Lewis for the gathering and processing of rich gas it produces from below the Olmos formation.

The total consideration we paid or granted to Lewis in connection with the Encinal acquisition is as follows:

Cash payment to Lewis	$	145.2
Fair value of our 7,115,844 common units issued to Lewis		181.1
Total consideration	$	326.3

In accordance with purchase accounting, the value of our common units issued to Lewis was based on the average closing price of such units immediately prior to and after the transaction was announced on July 12, 2006. For purposes of this calculation, the average closing price was $25.45 per unit.

Since the closing date of the Encinal acquisition was July 1, 2006, our Supplemental Statements of Consolidated Operations do not include any earnings from these assets prior to this date. Given the relative size of the Encinal acquisition to our other business combination transactions during 2006, the following table presents selected pro forma earnings information for the year ended December 31, 2006 as if the Encinal acquisition had been completed on January 1, 2006, instead of July 1, 2006. This information was prepared based on financial data available to us and reflects certain estimates and assumptions made by our management. Our pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had the Encinal acquisition actually occurred on January 1, 2006. The amounts shown in the following table are in millions, except per unit amounts.

	For the Year Ended December 31, 2006
Pro forma earnings data:	
Revenues	$ 23,685.9
Costs and expenses	22,591.5
Operating income	1,119.6
Net income attributable to Enterprise Products Partners L.P.	598.0
Basic earnings per unit (“EPU”):	
Units outstanding, as reported	414.4
Units outstanding, pro forma	421.5
Basic EPU, as reported	$ 1.20
Basic EPU, pro forma	$ 1.17
Diluted EPU:	
Units outstanding, as reported	414.7
Units outstanding, pro forma	421.8
Diluted EPU, as reported	$ 1.20
Diluted EPU, pro forma	$ 1.17

Piceance Creek Acquisition. In December 2006, we purchased a 100% interest in Piceance Creek Pipeline, LLC (“Piceance Creek”), for $100.0 million. Piceance Creek was wholly owned by EnCana.

The assets of Piceance Creek consist of a recently constructed 48-mile natural gas gathering pipeline, the Piceance Creek Gathering System, located in the Piceance Basin of northwestern Colorado. The Piceance Creek Gathering System has a transportation capacity of 1.6 Bcf/d of natural gas and extends from a connection with EnCana’s Great Divide Gathering System located near Parachute, Colorado, northward through the heart of the Piceance Basin to our 1.4 Bcf/d Meeker natural gas treating and processing complex. Connectivity to EnCana’s Great Divide Gathering System (see above for our purchase of this system in 2008) will provide the Piceance Creek Gathering System with access to production from the southern portion of the Piceance basin, including production from EnCana’s Mamm Creek field. The Piceance Creek Gathering System was placed in service in January 2007 and began transporting initial volumes of approximately 300 million cubic feet per day (“MMcf/d”) of natural gas. In conjunction with our acquisition of Piceance Creek, EnCana signed a long-term, fixed fee gathering agreement with us and dedicated significant production to the Piceance Creek Gathering System for the life of the associated lease holdings.

Other Transactions. In addition to the Encinal and Piceance Creek acquisitions, our business combinations during 2006 included the purchase of (i) an additional 8.2% ownership interest in Dixie for $12.9 million, (ii) all of the capital stock of an affiliated NGL marketing company located in Canada from related parties for $17.7 million (see Note 17), (iii) a storage business near Watkins Glen, New York from New York LP Gas Storage, Inc. for $9.9 million, (iv) a refined products terminal in Aberdeen, Mississippi, for $5.8 million, and (v) a storage business in Flagstaff, Arizona for $0.7 million.

Note 13. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets at the dates indicated:

	December 31, 2008			December 31, 2007		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services: (1)						
Customer relationship intangibles	$ 237.4	$ (68.7)	$ 168.7	$ 224.6	$ (49.0)	$ 175.6
Contract-based intangibles	320.3	(137.6)	182.7	316.1	(116.6)	199.5
Segment total	557.7	(206.3)	351.4	540.7	(165.6)	375.1
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles (2)	372.0	(103.2)	268.8	362.3	(81.4)	280.9
Gas gathering agreements	464.0	(213.1)	250.9	464.0	(181.7)	282.3
Other contract-based intangibles	101.3	(36.6)	64.7	101.3	(28.0)	73.3
Segment total	937.3	(352.9)	584.4	927.6	(291.1)	636.5
Onshore Crude Oil Pipelines & Services:						
Contract-based intangibles	10.0	(3.1)	6.9	10.0	(2.7)	7.3
Segment total	10.0	(3.1)	6.9	10.0	(2.7)	7.3
Offshore Pipelines & Services:						
Customer relationship intangibles	205.8	(90.7)	115.1	205.8	(73.9)	131.9
Contract-based intangibles	1.2	(0.1)	1.1	1.2	(0.1)	1.1
Segment total	207.0	(90.8)	116.2	207.0	(74.0)	133.0
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.9	(13.8)	91.1	53.6	(9.1)	44.5
Contract-based intangibles (3)	41.1	(8.2)	32.9	21.1	(3.4)	17.7
Segment total	146.0	(22.0)	124.0	74.7	(12.5)	62.2
Total all segments	$ 1,858.0	$ (675.1)	$ 1,182.9	$ 1,760.0	$ (545.9)	$ 1,214.1

(1) In 2008, we acquired $6.0 million of certain permits related to our Mont Belvieu complex and had $12.7 million of purchase price allocation adjustments related to San Felipe customer relationships from the December 2007 South Monco acquisition.
(2) In 2008, we acquired $9.8 million of customer relationships due to the Great Divide business combination.
(3) In 2007, we paid $11.2 million for certain air emission credits related to our Morgan's Point facility.

The following table presents the amortization expense of our intangible assets by segment for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services	$ 40.7	$ 38.2	$ 33.1
Onshore Natural Gas Pipelines & Services	61.7	64.4	64.0
Onshore Crude Oil Pipelines & Services	0.5	0.5	0.6
Offshore Pipelines & Services	16.9	19.3	22.2
Petrochemical & Refined Products Services	10.2	2.8	2.2
Total all segments	$ 130.0	$ 125.2	$ 122.1

We estimate that amortization expense associated with existing intangible assets will approximate $122.2 million in 2009, $116.0 million in 2010, $108.2 million in 2011, $93.2 million in 2012 and $85.5 million in 2013.

In general, our intangible assets fall within two categories – contract-based intangible assets and customer relationships. The values assigned to such intangible assets are amortized to earnings using either (i) a straight-line approach or (ii) other methods that closely resemble the pattern in which the economic benefits of associated resource bases are estimated to be consumed or otherwise used, as appropriate.

Customer relationship intangible assets. Customer relationship intangible assets represent the estimated economic value assigned to certain relationships acquired in connection with business combinations and asset purchases whereby (i) we acquired information about or access to customers and now have regular contact with them and (ii) the customers now have the ability to make direct contact with us. Customer relationships may arise from contractual arrangements (such as supplier contracts and service contracts) and through means other than contracts, such as through regular contact by sales or service representatives.

At December 31, 2008, the carrying value of our customer relationship intangible assets was $643.7 million. The following information summarizes the significant components of this category of intangible assets:

§ San Juan Gathering System customer relationships – We acquired these customer relationships in connection with the GulfTerra Merger, which was completed on September 30, 2004. At December 31, 2008, the carrying value of this group of intangible assets was $238.8 million. These intangible assets are being amortized to earnings over their estimated economic life of 35 years through 2039. Amortization expense is recorded using a method that closely resembles the pattern in which the economic benefits of the underlying natural gas resource bases are expected to be consumed or otherwise used.

§ Offshore Pipeline & Platform customer relationships – We acquired these customer relationships in connection with the GulfTerra Merger. At December 31, 2008, the carrying value of this group of intangible assets was $115.2 million. These intangible assets are being amortized to earnings over their estimated economic life of 33 years through 2037. Amortization expense is recorded using a method that closely resembles the pattern in which the economic benefits of the underlying crude oil and natural gas resource bases are expected to be consumed or otherwise used.

§ Encinal natural gas processing customer relationship – We acquired this customer relationship in connection with our Encinal acquisition in 2006. At December 31, 2008, the carrying value of this intangible asset was $99.1 million. This intangible asset is being amortized to earnings over its estimated economic life of 20 years through 2026. Amortization expense is recorded using a method that closely resembles the pattern in which the economic benefit of the underlying natural gas resource bases are expected to be consumed or otherwise used.

Contract-based intangible assets. Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At December 31, 2008, the carrying value of our contract-based intangible assets was $539.2 million. The following information summarizes the significant components of this category of intangible assets:

§ Jonah natural gas gathering agreements – These intangible assets represent the value attributed to certain of Jonah's natural gas gathering contracts that were originally acquired by TEPPCO in 2001. At December 31, 2008, the carrying value of this group of intangible assets was $136.0 million. These intangible assets are being amortized to earnings using a units-of-production method based on throughput volumes on the Jonah system.

§ Val Verde natural gas gathering agreements – These intangible assets represent the value attributed to certain natural gas gathering agreements associated with our Val Verde Gathering System that was originally acquired by TEPPCO in 2002. At December 31, 2008, the carrying value of these intangible assets was $113.8 million. These intangible assets are being amortized to earnings using a units-of-production method based on throughput volumes on the Val Verde Gathering System.

§ Shell Processing Agreement – This margin-band/keepwhole processing agreement grants us the right to process Shell Oil Company's (or its assignee's) current and future natural gas production of within the state and federal waters of the Gulf of Mexico. We acquired the Shell Processing Agreement in connection with our 1999 purchase of certain of Shell's midstream energy assets located along the U.S. Gulf Coast. At December 31, 2008, the carrying value of this intangible asset was $116.9 million. This intangible asset is being amortized to earnings on a straight-line basis over its estimated economic life of 20 years through 2019.

§ Mississippi natural gas storage contracts – These intangible assets represent the value assigned by us to certain natural gas storage contracts associated with our Petal and Hattiesburg, Mississippi storage facilities. These facilities were acquired in connection with the GulfTerra Merger. At December 31, 2008, the carrying value of these intangible assets was $64.0 million. These intangible assets are being amortized to earnings on a straight-line basis over the remainder of their respective contract terms, which range from eight to 18 years (i.e. 2012 through 2022).

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. We do not amortize goodwill; however, we test goodwill for impairment annually, or more frequently if circumstances indicate that it is more likely than not that the fair value of goodwill is less than its carrying value. The following table summarizes our goodwill amounts by business segment at the dates indicated:

	December 31, 2008	December 31, 2007
NGL Pipelines & Services		
Acquisition of ownership interests in TEPPCO	$ 72.2	$ 72.2
GulfTerra Merger	23.8	23.8
Acquisition of Encinal	95.3	95.3
Acquisition of additional ownership interests in Dixie	80.3	10.0
Acquisition of Great Divide	44.9	--
Acquisition of Indian Springs natural gas processing business	13.2	13.2
Other	11.5	11.5
Onshore Natural Gas Pipelines & Services		
GulfTerra Merger	279.9	279.9
Other	5.0	5.0
Onshore Crude Oil Pipeline & Services		
Acquisition of ownership interests in TEPPCO	288.8	288.8
Acquisition of crude oil pipeline and services business	14.2	14.2
Offshore Pipelines & Services		
GulfTerra Merger	82.1	82.1
Petrochemical & Refined Products Services		
Acquisition of ownership interests in TEPPCO	842.3	842.3
Acquisition of Mont Belvieu propylene fractionation business	73.7	73.7
Acquisition of marine transportation businesses	90.4	--
Other	2.0	1.3
Total	$ 2,019.6	$ 1,813.3

Changes in goodwill amounts during 2008. In 2008, our only significant changes to goodwill were the recording of $70.4 million in connection with our acquisition of the remaining third party interest in Dixie, $44.9 million in connection with the acquisition of Great Divide and $90.4 million in connection with our acquisitions of Cenac and Horizon. The remaining ownership interests in Dixie were acquired from Amoco Pipeline Holding Company in August 2008. Management attributes the goodwill to future earnings growth on the Dixie Pipeline. Specifically, a 100% ownership interest in the Dixie Pipeline will increase our flexibility to pursue future opportunities. Great Divide was acquired from EnCana in December 2008. The Great Divide goodwill is attributable to management's expectations of future economics benefits derived from incremental natural gas processing margins and other downstream activities.

The Dixie and Great Divide goodwill amounts are recorded as part of the NGL Pipelines & Services business segment due to management's belief that such future benefits will accrue to businesses classified within this segment. The marine services businesses goodwill amounts are recorded as part of the Petrochemical & Refined Products Services business segment due to management's belief of potential future economic benefits we expect to realize as a result of acquiring these assets. See Note 12 for additional information regarding our 2008 acquisitions that resulted in the recording of goodwill.

Goodwill attributable to the acquisition of ownership interests in TEPPCO. As a result of our ownership of 100% of the limited and general partner interests of TEPPCO following the recently completed TEPPCO Merger, we applied push-down accounting to the $1.2 billion of goodwill recorded by affiliates of EPCO (which are under common control with us) when they acquired 100% of the membership interests of TEPPCO GP and 4.4 million TEPPCO limited partner units from a third party in February 2005. The $1.2 billion in push down goodwill represents the excess of the purchase price paid by such affiliates to acquire ownership interests in TEPPCO in February 2005 over the respective fair value of assets acquired and liabilities assumed in the February 2005 transaction. Management attributes the $1.2 billion of goodwill to the future economic benefits we may realize from our ownership of TEPPCO, including anticipated commercial synergies and cost savings.

TEPPCO owns and operates an extensive network of assets that facilitate the movement, marketing, gathering and storage services of various commodities and energy-related products. TEPPCO's pipeline network is comprised of approximately 12,500 miles of pipelines that gather and transport refined petroleum products, crude oil, natural gas and NGLs, including one of the largest common carrier pipelines for refined products in the United States. TEPPCO also owns a marine services business that transports refined petroleum products, crude oil, asphalt, condensate, heavy fuel oil and other heated oil products via tow boats and tank barges. In addition, TEPPCO owns interests in the Seaway and Centennial pipeline systems.

Goodwill attributable to GulfTerra Merger. Goodwill recorded in connection with the GulfTerra Merger can be attributed to our belief (at the time the merger was consummated) that the combined partnerships would benefit from the strategic location of each partnership's assets and the industry relationships that each possessed. In addition, we expected that various operating synergies could develop (such as reduced general and administrative costs and interest savings) that would result in improved financial results for the merged entity. Based on miles of pipelines, GulfTerra was one of the largest natural gas gathering and transportation companies in the United States, serving producers in the central and western Gulf of Mexico and onshore in Texas and New Mexico. These regions offer us significant growth potential through the acquisition and construction of additional pipelines, platforms, processing and storage facilities and other midstream energy infrastructure.

Acquisition of Encinal. Management attributes goodwill recorded in connection with the Encinal acquisition to potential future benefits we may realize from our other south Texas processing and NGL businesses as a result of acquiring the Encinal business. Specifically, our acquisition of the long-term dedication rights associated with the Encinal business is expected to add value to our south Texas processing facilities and related NGL businesses due to increased volumes. The Encinal goodwill is recorded as part of the NGL Pipelines & Services business segment due to management's belief that such future benefits will accrue to businesses classified within this segment.

Other goodwill amounts. The remainder of our goodwill amounts are associated with prior acquisitions, principally that of our crude oil pipeline and services business originally purchased by TEPPCO in 2001, our purchase of a propylene fractionation business in February 2002 and our acquisition of indirect ownership interests in the Indian Springs natural gas gathering and processing business in January 2005.

Note 14. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated:

	December 31, 2008	December 31, 2007
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due November 2012	$ 800.0	$ 725.0
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54.0	54.0
Petal GO Zone Bonds, variable rate, due August 2037	57.5	57.5
Yen Term Loan, 4.93% fixed-rate, due March 2009 (1)	217.6	--
Senior Notes B, 7.50% fixed-rate, due February 2011	450.0	450.0
Senior Notes C, 6.375% fixed-rate, due February 2013	350.0	350.0
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes F, 4.625% fixed-rate, due October 2009 (1)	500.0	500.0
Senior Notes G, 5.60% fixed-rate, due October 2014	650.0	650.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes I, 5.00% fixed-rate, due March 2015	250.0	250.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes K, 4.950% fixed-rate, due June 2010	500.0	500.0
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes M, 5.65% fixed-rate, due April 2013	400.0	--
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	--
Senior Notes O, 9.75% fixed-rate, due January 2014	500.0	--
TEPPCO senior debt obligations:		
TEPPCO Revolving Credit Facility, variable rate, due December 2012	516.7	490.0
TEPPCO Senior Notes,7.625% fixed-rate, due February 2012	500.0	500.0
TEPPCO Senior Notes, 6.125% fixed-rate, due February 2013	200.0	200.0
TEPPCO Senior Notes, 5.90% fixed-rate, due April 2013	250.0	--
TEPPCO Senior Notes, 6.65% fixed-rate, due April 2018	350.0	--
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	400.0	--
TE Products Senior Notes, 6.45% fixed-rate, due January 2008	--	180.0
TE Products Senior Notes, 7.51% fixed-rate, due January 2028	--	175.0
Duncan Energy Partners' debt obligations:		
DEP I Revolving Credit Facility, variable rate, due February 2011	202.0	200.0
DEP II Term Loan Agreement, variable rate, due December 2011	282.3	--
Dixie Revolving Credit Facility, variable rate, due June 2010 (2)	--	10.0
Total principal amount of senior debt obligations	10,030.1	7,191.5
EPO Junior Subordinated Notes A, fixed/variable rate, due August 2066	550.0	550.0
EPO Junior Subordinated Notes B, fixed/variable rate, due January 2068	682.7	700.0
TEPPCO Junior Subordinated Notes, fixed/variable rate, due June 2067	300.0	300.0
Total principal amount of senior and junior debt obligations	11,562.8	8,741.5
Other, non-principal amounts:		
Change in fair value of debt-related derivative instruments (see Note 7)	51.9	14.8
Unamortized discounts, net of premiums	(12.6)	(7.3)
Unamortized deferred net gains related to terminated interest rate swaps (see Note 7)	35.8	22.1
Total other, non-principal amounts	75.1	29.6
Less current maturities of debt	--	(354.0)
Total long-term debt	$ 11,637.9	$ 8,417.1
Standby letters of credit outstanding	$ 1.0	$ 24.6

(1) In accordance with SFAS 6, Classification of Short-Term Obligations Expected to be Refinanced, long-term and current maturities of debt reflects the classification of such obligations at December 31, 2008. With respect to the Yen Term Loan and Senior Notes F due in October 2009, we have the ability to use available credit capacity under EPO's Multi-Year Revolving Credit Facility to fund the repayment of this debt.

(2) The Dixie Revolving Credit Facility was terminated in January 2009.

Letters of credit

At December 31, 2008, we had $1.0 million in standby letters outstanding under Duncan Energy Partners' DEP I Revolving Credit Facility. At December 31, 2007, we had $24.6 million of standby letters of credit outstanding, $1.1 million under Duncan Energy Partners' DEP I Revolving Credit Facility and $23.5 million under the TEPPCO Revolving Credit Facility.

Parent-Subsidiary guarantor relationships

Enterprise Products Partners L.P. acts as guarantor of the consolidated debt obligations of EPO with the exception of the DEP I Revolving Credit Facility and the DEP II Term Loan Agreement. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation.

TE Products Pipeline Company, LLC ("TE Products"), TCTM, L.P., TEPPCO Midstream Companies, LLC, and Val Verde Gas Gathering Company, L.P. (collectively, the "Subsidiary Guarantors") act as guarantors of TEPPCO's senior notes and Revolving Credit Facility. The Subsidiary Guarantors also act as guarantors, on a junior subordinated basis, of TEPPCO's junior subordinated notes. The guarantees are full, unconditional and joint and several. If TEPPCO were to default on any of its guaranteed debt, the Subsidiary Guarantors would be responsible for full repayment of that obligation. TEPPCO's debt obligations are non-recourse to Enterprise Products Partners L.P. As a result of the debt exchanges related to the TEPPCO Merger and the repayment and termination of the TEPPCO Revolving Credit Facility by EPO in October 2009, only $54.3 million of the TEPPCO senior and junior subordinated notes outstanding at December 31, 2008 (or 2.2%) remain guaranteed by the Guarantor Subsidiaries. These subsidiary guarantees were terminated in November 2009.

EPO's debt obligations

Multi-Year Revolving Credit Facility. In November 2007, EPO executed an amended and restated Multi-Year Revolving Credit Facility totaling $1.75 billion, which replaced an existing $1.25 billion multi-year revolving credit agreement. Amounts borrowed under the amended and restated credit agreement mature in November 2012, although EPO is permitted, 30 to 60 days before the maturity date in effect, to convert the principal balance of the revolving loans then outstanding into a non-revolving, one-year term loan (the "term-out option"). There is no sublimit on the amount of standby letters of credit that can be outstanding under the amended facility. EPO's borrowings under this agreement are unsecured general obligations that are non-recourse to EPGP. We have guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

As defined by the credit agreement, variable interest rates charged under this facility bear interest at a Eurodollar rate plus an applicable margin. In addition, EPO is required to pay a quarterly facility fee on each lender's commitment irrespective of commitment usage.

The applicable margins will be increased by 0.10% per annum for each day that the total outstanding loans and letter of credit obligations under the facility exceeds 50% of the total lender commitments. Also, upon the conversion of the revolving loans to term loans pursuant to the term-out option described above, the applicable margin will increase by 0.125% per annum and, if immediately prior to such conversion, the total amount of outstanding loans and letter of credit obligations under the facility exceeds 50% of the total lender commitments, the applicable margin with respect to the term loans will increase by an additional 0.10% per annum.

EPO may increase the amount that may be borrowed under the facility, without the consent of the lenders, by an amount not exceeding $500.0 million by adding to the facility one or more new lenders and/or requesting that the commitments of existing lenders be increased, although none of the existing lenders has agreed to or is obligated to increase its existing commitment. EPO may request unlimited one-year extensions of the maturity date by delivering a written request to the administrative agent, but any such extension shall be effective only if consented to by the required lenders in their sole discretion.

The Multi-Year Revolving Credit Facility contains various covenants related to EPO's ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires EPO to satisfy certain financial covenants at the end of each fiscal quarter. The credit agreement also restricts EPO's ability to pay cash distributions to us if a default or an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid.

Pascagoula MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant in 2000, EPO entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). This loan is subject to a make-whole redemption right and is guaranteed by us through an unsecured and unsubordinated guarantee. The Pascagoula MBFC Loan contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility.

The indenture agreement for this loan contains an acceleration clause whereby if EPO's credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's declining below BBB-, the $54.0 million principal balance of this loan, together with all accrued and unpaid interest, would become immediately due and payable 120 days following such event. If such an event occurred, we would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support our obligation under this loan.

Petal GO Zone Bonds. In August 2007, Petal borrowed $57.5 million from the MBFC pursuant to a loan agreement and promissory note between Petal Gas Storage, L.L.C. ("Petal") and the MBFC to pay a portion of the costs of certain natural gas storage facilities located in Petal, Mississippi. The promissory note between Petal and MBFC is guaranteed by EPO and supported by a letter of credit issued by Petal. On the same date, the MBFC issued $57.5 million in Gulf Opportunity Zone Tax-Exempt ("GO Zone") bonds to various third parties. A portion of the GO Zone bond proceeds were being held by a third party trustee and reflected as a component of other assets on our balance sheet. During 2008, virtually all proceeds from the GO Zone bonds were released by the trustee to fund construction costs associated with the expansion of our Petal, Mississippi storage facility. At December 31, 2007, $17.9 million of the GO Zone bond proceeds remained held by the third party trustee. The promissory note and the GO Zone bonds have identical terms including floating interest rates and maturities of 30 years. The bonds and the associated tax incentives are authorized under the Mississippi Business Finance Act and the Gulf Opportunity Zone Act of 2005.

Petal MBFC Loan. In August 2007, Petal, a wholly owned subsidiary of EPO, entered into a loan agreement and a promissory note with the MBFC under which Petal may borrow up to $29.5 million. On the same date, the MBFC issued taxable bonds to EPO in the maximum amount of $29.5 million. As of December 31, 2008, there was $8.9 million outstanding under the loan and the bonds. EPO will make advances on the bonds to the MBFC and the MBFC will in turn make identical advances to Petal under the promissory note. The promissory note and the taxable bonds have identical terms including fixed interest rates of 5.90% and maturities of fifteen years. The bonds and the associated tax incentives are authorized under the Mississippi Business Finance Act. Petal may prepay on the promissory note without penalty, and thus cause the bonds to be redeemed, any time after one year from their date of issue. The loan and bonds are netted in preparing our Supplemental Consolidated Balance Sheets, as well the related interest expense and income amounts are netted in preparing our Supplemental Statements of Consolidated Operations.

Japanese Yen Term Loan. In November 2008, EPO executed the Yen Term Loan in the amount of approximately 20.7 billion yen (approximately $217.6 million U.S. Dollar equivalent on the closing date). EPO's obligations under the Yen Term Loan are not secured by any collateral; however, the obligations are guaranteed by Enterprise Products Partners L.P. pursuant to a guaranty agreement. The Yen Term Loan will mature on March 30, 2009.

Under the Yen Term Loan, interest accrues on the loan at the Tokyo Interbank Offered Rate ("TIBOR") plus 2.0%. EPO entered into foreign exchange currency swaps that effectively convert the TIBOR loan into a U.S. Dollar loan with a fixed interest rate (including the cost of the swaps) through maturity of approximately 4.93%. As a result, EPO received US$217.6 million net from this transaction. In addition, EPO executed a forward purchase exchange (yen principal and interest due) for March 30, 2009 at an exchange rate of 94.515 to eliminate foreign exchange risk, resulting in a payment of US$221.6 million on March 30, 2009. For additional information see Note 7.

364-Day Revolving Credit Facility. In November 2008, EPO executed a 364-Day Revolving Credit Agreement ("364-Day Revolving Credit Facility") in the amount of $375.0 million. EPO's obligations under the 364-Day Revolving Credit Facility are not secured by any collateral; however, the obligations are guaranteed by Enterprise Products Partners L.P. pursuant to a guaranty agreement. The 364-Day Revolving Credit Facility will mature on November 16, 2009. As of December 31, 2008, there were no borrowings outstanding under this credit facility.

The 364-Day Revolving Credit Facility offers the following loans, each having different interest requirements: (i) LIBOR loans bear interest at a rate per annum equal to LIBOR plus the applicable LIBOR margin and (ii) Base Rate loans bear interest each day at a rate per annum equal to the higher of (a) the rate of interest announced by the administrative agent as its prime rate, (b) 0.5% per annum above the Federal Funds Rate in effect on such date , and (c) 1.0% per annum above LIBOR in effect on such date plus, in each case, the applicable Base Rate margin.

The commitments may be increased by an amount not to exceed $1.0 billion by adding one or more new lenders to the facility or increasing the commitments of existing lenders, although none of the existing lenders has agreed to or is obligated to increase its existing commitment. With certain exceptions and after certain time periods, if EPO issues debt with a maturity of more than three years, the lenders' commitments under the 364-Day Revolving Credit Facility will be reduced to the extent of any debt proceeds, and any outstanding loans in excess of such reduced commitments must be repaid.

Senior Notes B through L. These fixed-rate notes are unsecured obligations of EPO and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. EPO's borrowings under these notes are non-recourse to EPGP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. Our guarantee of such notes is non-recourse to EPGP. The Senior Notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

EPO used net proceeds from its issuance of Senior Notes L in 2007 to temporarily reduce indebtedness outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. In October 2007, EPO used borrowing capacity under its Multi-Year Revolving Credit Facility to repay its $500.0 million Senior Notes E.

Senior Notes M and N. In April 2008, EPO sold $400.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes M") and $700.0 million in principal amount of 10-year senior unsecured notes ("Senior Notes N") under its universal registration statement. Senior Notes M were issued at 99.906% of their principal amount, have a fixed interest rate of 5.65% and mature in April 2013. Senior Notes N were issued at 99.866% of their principal amount, have a fixed interest rate of 6.50% and mature in January 2019.

Senior Notes M pay interest semi-annually in arrears on April 1 and October 1 of each year. Senior Notes N pay interest semi-annually in arrears on January 31 and July 31 of each year. Net proceeds from the issuance of Senior Notes M and N were used to temporarily reduce indebtedness outstanding under the EPO Multi-Year Revolving Credit Facility.

Senior Notes M and N rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes M and N are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Senior Notes O. In December 2008, EPO sold $500.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes O") under its universal registration statement. Senior Notes O were issued at 100% of their principal amount, have a fixed interest rate of 9.75% and mature in January 2014.

Senior Notes O pay interest semi-annually in arrears on January 31 and July 31 of each year, commencing January 31, 2009. Net proceeds from the issuance of Senior Notes O were used to temporarily reduce indebtedness outstanding under the EPO Multi-Year Revolving Credit Facility.

Senior Notes O rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes O are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Junior Notes A. In the third quarter of 2006, EPO sold $550.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due 2066 ("Junior Notes A"). EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. EPO's payment obligations under Junior Notes A are subordinated to all of its current and future senior indebtedness (as defined in the related indenture agreement). We guaranteed EPO's repayment of amounts due under Junior Notes A through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes A allows EPO to defer interest payments on one or more occasions for up to ten consecutive years, subject to certain conditions. The indenture agreement also provides that, unless (i) all deferred interest on Junior Notes A has been paid in full as of the most recent interest payment date, (ii) no event of default under the indenture agreement has occurred and is continuing and (iii) we are not in default of our obligations under related guarantee agreements, neither we nor EPO cannot declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinated to the Junior Notes A.

The Junior Notes A bear interest at a fixed annual rate of 8.375% from July 2006 to August 2016, payable semi-annually in arrears in February and August of each year, which commenced in February 2007. After August 2016, the Junior Notes A will bear variable rate interest at an annual rate equal to the 3-month LIBOR rate for the related interest period plus 3.708%, payable quarterly in arrears in February, May, August and November of each year commencing in November 2016. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to the certain provisions. The Junior Notes A mature in August 2066 and are not redeemable by EPO prior to August 2016 without payment of a make-whole premium.

In connection with the issuance of Junior Notes A, EPO entered into a Replacement Capital Covenant in favor of the covered debt holders (as defined in the underlying documents) pursuant to which EPO agreed for the benefit of such debt holders that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made using proceeds from the issuance of certain securities.

Junior Notes B. EPO sold $700.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due January 2068 ("Junior Notes B") during the second quarter of 2007. EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. EPO's payment obligations under Junior Notes B are subordinated to all of its current and future senior indebtedness (as defined in the

Indenture Agreement). We have guaranteed repayment of amounts due under Junior Notes B through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes B allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. During any period in which interest payments are deferred and subject to certain exceptions, neither we nor EPO can declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinate to Junior Notes B. Junior Notes B rank pari passu with Junior Notes A.

The Junior Notes B will bear interest at a fixed annual rate of 7.034% through January 15, 2018, payable semi-annually in arrears in January and July of each year, which commenced in January 2008. After January 2018, the Junior Notes B will bear variable rate interest at the greater of (1) the sum of the 3-month LIBOR for the related interest period plus a spread of 268 basis points or (2) 7.034% per annum, payable quarterly in arrears in January, April, July and October of each year commencing in April 2018. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to certain provisions. The Junior Notes B mature in January 2068 and are not redeemable by EPO prior to January 2018 without payment of a make-whole premium.

In connection with the issuance of Junior Notes B, we and EPO entered into a Replacement Capital Covenant in favor of the covered debt holders (as named therein) pursuant to which we and EPO agreed for the benefit of such debt holders that neither we nor EPO would redeem or repurchase such junior notes on or before January 15, 2038, unless such redemption or repurchase is made from the proceeds of issuance of certain securities.

During the fourth quarter of 2008, we retired $17.3 million of our Junior Notes B for $10.2 million. The $7.1 million gain on extinguishment of debt is included in “Other, net” on our Statement of Consolidated Operations.

TEPPCO’s debt obligations

TEPPCO Revolving Credit Facility. This unsecured revolving credit facility has a borrowing capacity of $950.0 million. In July 2008, commitments under this facility were increased from $700.0 million to $950.0 million. This credit facility matures in December 2012, but we may request unlimited extensions of the maturity date subject to certain conditions. There is no limit on the total amount of standby letters of credit that can be outstanding under this credit facility.

Variable interest rates charged under this facility generally bear interest, at our election at the time of each borrowing, at either (i) a LIBOR plus an applicable margin (as defined in the credit agreement) or (ii) the lender’s base rate as defined in the agreement.

The revolving credit agreement contains various covenants related to our ability to, among other things, incur certain indebtedness; grant certain liens; make certain distributions; engage in specified transactions with affiliates; and enter into certain merger or consolidation transactions. We must also satisfy certain financial covenants at the end of each fiscal quarter.

TEPPCO Short-Term Credit Facility. At December 31, 2007, we had in place an unsecured short term credit agreement (the “TEPPCO Short-Term Credit Facility”) with a borrowing capacity of $1.00 billion. No amounts were borrowed under this agreement at December 31, 2007. During the first quarter of 2008, we borrowed $1.00 billion under this credit agreement to finance the retirement of the TE Products’ senior notes, the acquisition of two marine service businesses and for other general partnership purposes. In March 2008, we repaid amounts borrowed under this credit agreement, using proceeds from the TEPPCO Senior Notes offering, and terminated the facility.

The following table summarizes our borrowing and repayment activity under this credit agreement during the first quarter of 2008:

Borrowings, January 2008 (1)	$ 355.0
Borrowings, February 2008 (2)	645.0
Repayments, March 2008	(1,000.0)
Balance, March 27, 2008 (3)	$ --

(1) Funds borrowed to finance the retirement of TE Products' senior notes.
(2) Funds borrowed to finance the marine services acquisitions and for general partnership purposes.
(3) TEPPCO's Short-Term Credit Facility was terminated on March 27, 2008 upon full repayment of borrowings thereunder.

TEPPCO Senior Notes. In February 2002 and January 2003, TEPPCO issued 7.625% Senior Notes and 6.125% Senior Notes, respectively. In March 2008, TEPPCO sold $250.0 million in principal amount of 5-year senior unsecured notes, $350.0 million in principal amount of 10-year senior unsecured notes and $400.0 million in principal amount of 30-year senior unsecured notes. The 5-year senior notes were issued at 99.922% of their principal amount, have a fixed interest rate of 5.90%, and mature in April 2013. The 10-year senior notes were issued at 99.640% of their principal amount, have a fixed interest rate of 6.65%, and mature in April 2018. The 30-year senior notes were issued at 99.451% of their principal amount, have a fixed interest rate of 7.55%, and mature in April 2038.

The senior notes issued in March 2008 pay interest semi-annually in arrears on April 15 and October 15 of each year, beginning October 15, 2008. Net proceeds from the issuance of these notes were used to repay and terminate the TEPPCO Short-Term Credit Facility. The notes issued in March 2008 rank pari passu with our existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness.

The TEPPCO Senior Notes are subject to make-whole redemption rights and are redeemable at any time at our option. The indenture agreements governing these notes contain certain covenants, including, but not limited to the creation of liens securing indebtedness and sale and leaseback transactions. However, the indentures do not limit our ability to incur additional indebtedness.

TE Products Senior Notes. In January 1998, TE Products issued its 6.45% Senior Notes due January 2008 and 7.51% Senior Notes due January 2028. In January 2008, the 6.45% TE Products Senior Notes matured. The $180.0 million principal amount was repaid with borrowings under the TEPPCO Short-Term Credit Facility. In October 2007 a portion of the 7.51% Senior Notes was redeemed and in January 2008 the remaining $175.0 million was redeemed at a redemption price of 103.755% of the principal amount plus accrued interest and unpaid interest at the date of redemption. The $175.0 million principal amount was repaid with borrowings under the TEPPCO Short-Term Credit Facility.

TEPPCO Junior Subordinated Notes. In May 2007, TEPPCO sold $300.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due June 1, 2067 ("TEPPCO Junior Subordinated Notes"). We used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under the TEPPCO Revolving Credit Facility and for general partnership purposes. The payment obligations under the TEPPCO Junior Subordinated Notes are subordinated to all of its current and future senior indebtedness (as defined in the related indenture).

The indenture governing the TEPPCO Junior Subordinated Notes does not limit our ability to incur additional debt, including debt that ranks senior to or equally with the TEPPCO Junior Subordinated Notes. The indenture allows us to defer interest payments on one or more occasions for up to ten consecutive years, subject to certain conditions. During any period in which interest payments are deferred and subject to certain exceptions, (i) we cannot declare or make any distributions to any of its respective equity securities and (ii) neither we nor the Subsidiary Guarantors can make any payments on indebtedness or other obligations that rank pari passu with or are subordinated to the TEPPCO Junior Subordinated Notes.

The TEPPCO Junior Subordinated Notes bear interest at a fixed annual rate of 7.0% from May 2007 to June 1, 2017, payable semi-annually in arrears. After June 1, 2017, the TEPPCO Junior Subordinated Notes will bear interest at a variable annual rate equal to the 3-month LIBOR for the related interest period plus 2.7775%, payable quarterly in arrears. The TEPPCO Junior Subordinated Notes mature in June 2067. The TEPPCO Junior Subordinated Notes are redeemable in whole or in part prior to June 1, 2017 for a "make-whole" redemption price and thereafter at a redemption price equal to 100% of their principal amount plus accrued and unpaid interest. The TEPPCO Junior Subordinated Notes are also redeemable prior to June 1, 2017 in whole (but not in part) upon the occurrence of certain tax or rating agency events at specified redemption prices.

In connection with the issuance of the TEPPCO Junior Subordinated Notes, we and the Subsidiary Guarantors entered into a Replacement Capital Covenant in favor of holders (as provided therein) pursuant to which we and the Subsidiary Guarantors agreed for the benefit of such debt holders that it would not redeem or repurchase the TEPPCO Junior Subordinated Notes on or before June 1, 2037, unless such redemption or repurchase is from proceeds of issuance of certain securities.

Duncan Energy Partners' debt obligations

We consolidate the debt of Duncan Energy Partners with that of our own; however, we do not have the obligation to make interest payments or debt payments with respect to the debt of Duncan Energy Partners.

DEP I Revolving Credit Facility. In February 2007, Duncan Energy Partners entered into a $300.0 million revolving credit facility, all of which may be used for letters of credit, with a $30.0 million sublimit for Swingline loans. Letters of credit outstanding under this facility reduce the amount available for borrowings. At the closing of its initial public offering, Duncan Energy Partners made its initial borrowing of $200.0 million under the facility to fund a $198.9 million cash distribution to EPO and the remainder to pay debt issuance costs. At December 31, 2008, the principal balance outstanding under this facility was $202.0 million.

This credit facility matures in February 2011 and will be used by Duncan Energy Partners in the future to fund working capital and other capital requirements and for general partnership purposes. Duncan Energy Partners may make up to two requests for one-year extensions of the maturity date (subject to certain restrictions). The revolving credit facility is available to pay distributions upon the initial contribution of assets to Duncan Energy Partners, fund working capital, make acquisitions and provide payment for general purposes. Duncan Energy Partners can increase the revolving credit facility, without consent of the lenders, by an amount not to exceed $150.0 million by adding to the facility one or more new lenders and/or increasing the commitments of existing lenders. No existing lender is required to increase its commitment, unless it agrees to do so in its sole discretion.

This revolving credit facility offers the following unsecured loans, each having different interest requirements: (i) a Eurodollar rate, plus the applicable Eurodollar margin (as defined in the credit agreement), (ii) Base Rate loans bear interest at a rate per annum equal to the higher of (a) the rate of interest publicly announced by the administrative agent, Wachovia Bank, National Association, as its Base Rate and (b) 0.5% per annum above the Federal Funds Rate in effect on such date and (iii) Swingline loans bear interest at a rate per annum equal to LIBOR plus an applicable LIBOR margin.

The Duncan Energy Partners' credit facility contains certain financial and other customary covenants. Also, if an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity date of amounts borrowed under the credit agreement and exercise other rights and remedies.

DEP II Term Loan Agreement. In April 2008, Duncan Energy Partners entered into a standby term loan agreement consisting of commitments for up to a $300.0 million senior unsecured term loan. Subsequently, commitments under this agreement decreased to $282.3 million due to bankruptcy of one of the lenders. Duncan Energy Partners borrowed the full amount of $282.3 million on December 8, 2008 in connection with the acquisition of equity interests in the DEP II Midstream Businesses. See “Relationship with Duncan Energy Partners” in Note 17 for additional information regarding the DEP II Midstream Businesses.

Loans under the term loan agreement are due and payable on December 8, 2011. Duncan Energy Partners may also prepay loans under the term loan agreement at any time, subject to prior notice in accordance with the credit agreement. Loans may also be payable earlier in connection with an event of default.

Loans under the term loan agreement bear interest of the type specified in the applicable borrowing request, and consist of either Alternate Base Rate (“ABR”) loans or Eurodollar loans. The term loan agreement contains customary affirmative and negative covenants.

Dixie Revolving Credit Facility

Dixie’s debt obligation consisted of a senior, unsecured revolving credit facility having a borrowing capacity of $28.0 million. As of December 31, 2008, there were no debt obligations outstanding under the Dixie Revolver. This credit facility was terminated in January 2009. EPO consolidated the debt of Dixie; however, EPO did not have the obligation to make interest or debt payments with respect to Dixie’s debt.

Variable interest rates charged under this facility generally bore interest, at Dixie’s election at the time of each borrowing, at either (i) a Eurodollar rate plus an applicable margin or (ii) the greater of (a) the prime rate or (b) the Federal Funds Effective Rate plus 0.5%.

Canadian Debt Obligation

In May 2007, Canadian Enterprise Gas Products, Ltd. (“Canadian Enterprise”), a wholly owned subsidiary of EPO, entered into a $30.0 million Canadian revolving credit facility with The Bank of Nova Scotia. The credit facility, which includes the issuance of letters of credit, matures in October 2011. Letters of credit outstanding under this facility reduce the amount available for borrowings.

Borrowings may be made in Canadian or U.S. dollars. Canadian denominated borrowings may be comprised of Canadian Prime Rate (“CPR”) loans or Bankers’ Acceptances and U.S. denominated borrowings may be comprised of ABR or Eurodollar loans, each having different interest rate requirements. CPR loans bear interest at a rate determined by reference to the Canadian Prime Rate. ABR loans bear interest at a rate determined by reference to an alternative base rate as defined in the credit agreement. Eurodollar loans bear interest at a rate determined by the LIBOR plus an applicable rate as defined in the credit agreement. Bankers’ Acceptances carry interest at the rate for Canadian bankers’ acceptances plus an applicable rate as defined in the credit agreement.

The credit facility contains customary covenants and events of default. The restrictive covenants limit Canadian Enterprise from materially changing the nature of its business or operations, dissolving, or completing mergers. A continuing event of default would accelerate the maturity of amounts borrowed under the credit facility. The obligations under the credit facility are guaranteed by EPO. As of December 31, 2008, there were no debt obligations outstanding under this credit facility.

Covenants

We are in compliance with the covenants of our consolidated debt agreements at December 31, 2008 and 2007.

Information regarding variable interest rates paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt obligations during the year ended December 31, 2008.

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO's Multi-Year Revolving Credit Facility	0.97% to 6.00%	3.54%
TEPPCO Revolving Credit Facility	1.06% to 2.24%	1.40%
TEPPCO Short-Term Credit Facility	3.59% to 4.96%	4.02%
DEP I Revolving Credit Facility	1.30% to 6.20%	4.25%
DEP II Term Loan Agreement	2.93% to 2.93%	2.93%
Dixie Revolving Credit Facility	0.81% to 5.50%	3.20%
Petal GO Zone Bonds	0.78% to 7.90%	2.24%

Consolidated debt maturity table

The following table presents scheduled maturities of our consolidated debt obligations for the next five years, and in total thereafter.

2009	$ --
2010	554.0
2011	934.3
2012	2,534.3
2013	1,200.0
Thereafter	6,340.2
Total scheduled principal payments	$ 11,562.8

In accordance with SFAS 6, long-term and current maturities of debt reflect the classification of such obligations at December 31, 2008.

Debt Obligations of Unconsolidated Affiliates

We have three unconsolidated affiliates with long-term debt obligations. The following table shows (i) the ownership interest in each entity at December 31, 2008, (ii) total debt of each unconsolidated affiliate at December 31, 2008 (on a 100% basis to the unconsolidated affiliate) and (iii) the corresponding scheduled maturities of such debt.

			Scheduled Maturities of Debt					
	Ownership Interest	Total	2009	2010	2011	2012	2013	After 2013
Poseidon	36%	$ 109.0	$ --	$ --	$ 109.0	$ --	$ --	$ --
Evangeline	49.5%	15.7	5.0	3.2	7.5	--	--	--
Centennial	50%	129.9	9.9	9.1	9.0	8.9	8.6	84.4
Total		$ 254.6	$ 14.9	$ 12.3	$ 125.5	$ 8.9	$ 8.6	$ 84.4

The credit agreements of these unconsolidated affiliates include customary covenants, including financial covenants. These businesses were in compliance with such covenants at December 31, 2008. The credit agreements of these unconsolidated affiliates restrict their ability to pay cash dividends or distributions if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend or distribution is scheduled to be paid.

The following information summarizes the significant terms of the debt obligations of these unconsolidated affiliates at December 31, 2008:

Poseidon. Poseidon has a $150.0 million variable-rate revolving credit facility that matures in May 2011. This credit agreement is secured by substantially all of Poseidon's assets. The variable interest rates charged on this debt at December 31, 2008 and December 31, 2007 were 4.31% and 6.62%, respectively.

Evangeline. At December 31, 2008, Evangeline's debt obligations consisted of (i) $8.2 million of 9.90% fixed-rate Series B senior secured notes due December 2010 and (ii) a $7.5 million subordinated note payable. The Series B senior secured notes are collateralized by Evangeline's property, plant and equipment; proceeds from a gas sales contract and by a debt service reserve requirement. Scheduled principal repayments on the Series B notes are $5.0 million in 2009 with a final repayment in 2010 of approximately $3.2 million.

Evangeline incurred the subordinated note payable as a result of its acquisition of a contract-based intangible asset in the early 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the subordinated note until such time as the Series B noteholders are either fully cash secured through debt service accounts or have been completely repaid.

Variable rate interest accrues on the subordinated note at a Eurodollar rate plus 0.5%. The variable interest rates charged on this note at December 31, 2008 and December 31, 2007 were 3.20% and 5.88%, respectively. Accrued interest payable related to the subordinated note was $9.8 million and $9.1 million at December 31, 2008 and December 31, 2007, respectively.

Centennial. At December 31, 2008, Centennial's debt obligations consisted of $129.9 million borrowed under a master shelf loan agreement. Borrowings under the master shelf agreement mature in May 2024 and are collateralized by substantially all of Centennial's assets and severally guaranteed by Centennial's owners.

TEPPCO and its joint venture partner in Centennial have each guaranteed one-half of Centennial's debt obligations. If Centennial defaults on its debt obligations, the estimated payment obligation is $65.0 million. At December 31, 2008, TEPPCO had recognized a liability of $9.0 million for its share of the Centennial debt guaranty. A downgrade of our credit ratings could result in our being required to post financial collateral up to the amount of our guaranty of indebtedness. Further, from time to time we enter into contracts in connection with our commodity and interest rate hedging activities and crude oil marketing business that require the posting of financial collateral, which may be substantial, if our credit were to be downgraded below investment grade.

Note 15. Equity and Distributions

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Fifth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the "Partnership Agreement"). We are managed by our general partner, EPGP.

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our supplemental consolidated financial statements.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and general partner will receive. The Partnership Agreement also contains provisions for the allocation of net earnings and losses to our limited partners and general partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. Normal income and loss allocations according to percentage interests are done only after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated to our general partner.

In August 2005, we revised our Partnership Agreement to allow EPGP, at its discretion, to elect not to make its proportionate capital contributions to us in connection with our issuance of limited partner interests, in which case its 2% general partner interest would be proportionately reduced. At the time of such offerings, EPGP has historically contributed cash to us to maintain its 2% general partner interest. EPGP made such cash contributions to us during the years ended December 31, 2008 and 2007. If EPGP exercises this option in the future, the amount of earnings we allocate to it and the cash distributions it receives from us will be reduced accordingly. If this occurs, EPGP can, under certain conditions, restore its full 2% general partner interest by making additional cash contributions to us.

Equity offerings and registration statements

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

In August 2007, we filed a universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities. In January 2009, we sold 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit under this universal shelf registration. See Note 25 for additional information.

During 2003, we instituted a distribution reinvestment plan (“DRIP”). In April 2007, we filed a registration statement with the SEC authorizing the issuance of up to 25,000,000 common units in connection with the DRIP. The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units. A total of 21,471,047 common units have been issued under this registration statement through December 31, 2008.

We also have a registration statement on file related to our employee unit purchase plan (“EUPP”), under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. A total of 651,297 common units have been issued to employees under this plan through December 31, 2008.

The following table reflects the number of common units issued and the net proceeds received from underwritten and other common unit offerings completed during the years ended December 31, 2008, 2007 and 2006:

		Net Proceeds from Sale of Common Units		
	Number of Common Units Issued	**Contributed by Limited Partners**	**Contributed by General Partner**	**Total Net Proceeds**
Fiscal 2006:				
Underwritten offerings	31,050,000	$ 735.8	$ 15.0	$ 750.8
DRIP and EUPP	3,774,649	95.0	2.0	97.0
Total 2006	34,824,649	$ 830.8	$ 17.0	$ 847.8
Fiscal 2007:				
DRIP and EUPP	2,056,615	$ 60.4	$ 1.2	$ 61.6
Total 2007	2,056,615	$ 60.4	$ 1.2	$ 61.6
Fiscal 2008:				
DRIP and EUPP	5,523,946	$ 139.3	$ 2.8	$ 142.1
Total 2008	5,523,946	$ 139.3	$ 2.8	$ 142.1

Net proceeds received from our underwritten and other offerings completed during 2006 were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Net proceeds received from our DRIP and EUPP were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Summary of Changes in Outstanding Units

The following table summarizes changes in our outstanding units since December 31, 2005:

	Common Units	Restricted Common Units	Treasury Units
Balance, December 31, 2005	389,109,564	751,604	--
Common units issued in connection with underwritten offerings	31,050,000	--	--
Common units issued in connection with DRIP and EUPP	3,774,649	--	--
Common units issued in connection with equity awards	211,000	466,400	--
Forfeiture of restricted units	--	(70,631)	--
Conversion of restricted units to common units	42,136	(42,136)	--
Common units issued in connection with Encinal acquisition	7,115,844	--	--
Balance, December 31, 2006	431,303,193	1,105,237	--
Common units issued in connection with DRIP and EUPP	2,056,615	--	--
Common units issued in connection with equity awards	244,071	738,040	--
Forfeiture or settlement of restricted units	--	(149,853)	--
Conversion of restricted units to common units	4,884	(4,884)	--
Balance, December 31, 2007	433,608,763	1,688,540	--
Common units issued in connection with DRIP and EUPP	5,523,946	--	--
Common units issued in connection with equity awards	21,905	--	--
Restricted units issued	--	766,200	--
Forfeiture or settlement of restricted units	--	(88,777)	--
Conversion of restricted units to common units	285,363	(285,363)	--
Acquisition of treasury units	(85,246)	--	85,246
Cancellation of treasury units	--	--	(85,246)
Balance, December 31, 2008	439,354,731	2,080,600	--

Treasury Units. In 2000, we and a consolidated trust (the "1999 Trust") were authorized by EPGP to repurchase up to 2,000,000 publicly-held common units under an announced buy-back program. The repurchases would be made during periods of temporary market weakness at price levels that would be accretive to our remaining unitholders. After deducting for repurchases under the program in prior periods, we and the 1999 Trust could repurchase up to 618,400 common units at December 31, 2008.

During the year ended December 31, 2008, 285,363 restricted unit awards vested and were converted to common units. Of this amount, 85,246 were sold back to us by employees to cover related withholding tax requirements. The total cost of these treasury units was approximately $1.9 million, of which a minimal amount was allocated to our general partner. Immediately upon acquisition, we cancelled such treasury units.

Summary of Changes in Limited Partners' Equity

The following table details the changes in limited partners' equity since December 31, 2005:

	Common Units	Restricted Common Units	Total
Balance, December 31, 2005	$ 5,542.7	$ 18.6	$ 5,561.3
Net income allocated to limited partners	503.0	1.1	504.1
Operating leases paid by EPCO	2.1	--	2.1
Cash distributions to partners	(738.0)	(1.6)	(739.6)
Unit option reimbursements to EPCO	(1.9)	--	(1.9)
Net proceeds from issuance of common units	830.8	--	830.8
Common units issued in connection with Encinal acquisition	181.1	--	181.1
Proceeds from exercise of unit options	5.6	--	5.6
Amortization of equity awards	2.2	6.1	8.3
Change in accounting method for equity awards (see Note 5)	(0.9)	(14.9)	(15.8)
Acquisition-related disbursement of cash	(6.2)	--	(6.2)
Balance, December 31, 2006	6,320.5	9.3	6,329.8
Net income allocated to limited partners	416.3	1.4	417.7
Operating leases paid by EPCO	2.1	--	2.1
Cash distributions to partners	(831.2)	(2.6)	(833.8)
Unit option reimbursements to EPCO	(3.0)	--	(3.0)
Net proceeds from issuance of common units	60.4	--	60.4
Proceeds from exercise of unit options	7.5	--	7.5
Repurchase of restricted units and options	(0.5)	(1.0)	(1.5)
Amortization of equity awards	4.9	8.8	13.7
Balance, December 31, 2007	5,977.0	15.9	5,992.9
Net income allocated to limited partners	807.9	3.6	811.5
Operating leases paid by EPCO	2.0	--	2.0
Cash distributions to partners	(888.8)	(3.9)	(892.7)
Unit option reimbursements to EPCO	(0.6)	--	(0.6)
Non-cash distributions	(7.1)	--	(7.1)
Acquisition of treasury units, limited partner share	--	(1.9)	(1.9)
Net proceeds from issuance of common units	139.3	--	139.3
Proceeds from exercise of unit options	0.7	--	0.7
Amortization of equity awards	6.5	12.5	19.0
Balance, December 31, 2008	$ 6,036.9	$ 26.2	$ 6,063.1

In October 2006, we acquired all of the capital stock of an affiliated NGL marketing company located in Canada from EPCO and Dan L. Duncan for $17.7 million in cash. The amount we paid for this business exceeded the carrying values of the assets acquired and liabilities assumed from this related party (which is under common control with us) by $6.3 million, of which $6.2 million was allocated to limited partners and $0.1 million to our general partner. The excess of the acquisition price over the net book value of this business at the time of acquisition is treated as a deemed distribution to our owners and presented as an "Acquisition-related disbursement of cash" in our Supplemental Statement of Equity for the year ended December 31, 2006. The total purchase price is a component of "Cash used for business combinations" as presented in our Supplemental Statement of Consolidated Cash Flows for the year ended December 31, 2006.

Distributions to Partners

The percentage interest of EPGP in our quarterly cash distributions is increased after certain specified target levels of quarterly distribution rates are met. At current distribution rates, we are in the highest tier of such incentive targets. EPGP's quarterly incentive distribution thresholds are as follows:

§ 2% of quarterly cash distributions up to $0.253 per unit;

§ 15% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit; and

§ 25% of quarterly cash distributions that exceed $0.3085 per unit.

We paid incentive distributions of $125.9 million, $107.4 million and $86.7 million to EPGP during the years ended December 31, 2008, 2007 and 2006, respectively.

The following table presents our declared quarterly cash distribution rates per unit since the first quarter of 2007 and the related record and distribution payment dates. The quarterly cash distribution rates per unit correspond to the fiscal quarters indicated. Actual cash distributions are paid within 45 days after the end of such fiscal quarter.

	Distribution per Unit	Record Date	Payment Date
2007			
1st Quarter	$0.4750	Apr. 30, 2007	May 10, 2007
2nd Quarter	$0.4825	Jul. 31, 2007	Aug. 9, 2007
3rd Quarter	$0.4900	Oct. 31, 2007	Nov. 8, 2007
4th Quarter	$0.5000	Jan. 31, 2008	Feb. 7, 2008
2008			
1st Quarter	$0.5075	Apr. 30, 2008	May 7, 2008
2nd Quarter	$0.5150	Jul. 31, 2008	Aug. 7, 2008
3rd Quarter	$0.5225	Oct. 31, 2008	Nov. 12, 2008
4th Quarter	$0.5300	Jan. 30, 2009	Feb. 9, 2009

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily includes the effective portion of the gain or loss on derivative instruments designated and qualified as a cash flow hedge, foreign currency adjustments and Dixie's minimum pension liability adjustments. Amounts accumulated in other comprehensive income (loss) from cash flow hedges are reclassified into earnings in the same period(s) in which the hedged forecasted transactions (such as a forecasted forward sale of NGLs) affect earnings. If it becomes probable that the forecasted transaction will not occur, the net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified.

The following table presents the components of accumulated other comprehensive income (loss) at the dates indicated:

	December 31, 2008	December 31, 2007
Commodity derivative instruments (1)	$ (114.1)	$ (40.3)
Interest rate derivative instruments (1)	(41.9)	11.1
Foreign currency hedges (1)	10.6	1.3
Foreign currency translation adjustment (2)	(1.3)	1.2
Pension and postretirement benefit plans (3)	(0.8)	0.6
Subtotal	(147.5)	(26.1)
Amount attributable to noncontrolling interest (4)	50.3	45.2
Total accumulated other comprehensive income (loss) in partners' equity	$ (97.2)	$ 19.1

(1) See Note 7 for additional information regarding these components of accumulated other comprehensive income (loss).
(2) Relates to transactions of our Canadian NGL marketing subsidiary.
(3) See Note 6 for additional information regarding pension and postretirement benefit plans.
(4) Represents the amount of accumulated other comprehensive loss allocated to noncontrolling interest based on the provisions of SFAS 160.

Noncontrolling Interest

Prior to the completion of the TEPPCO Merger, effective October 26, 2009, we accounted for our interest in TEPPCO and TEPPCO GP as noncontrolling interest. Under this method of presentation, all revenues and expenses of TEPPCO and TEPPCO GP are included in net income, and our share of the income of TEPPCO and TEPPCO GP is allocated to net income attributable to noncontrolling interest. In addition, our share of the net assets of TEPPCO and TEPPCO GP are presented as noncontrolling interest, a component of equity, on our Supplemental Consolidated Balance Sheets.

The following table presents the components of noncontrolling interest as presented on our Supplemental Consolidated Balance Sheets at the dates indicated:

	December 31,	
	2008	**2007**
Former owners of TEPPCO (1)	$ 2,827.6	$ 2,497.0
Limited partners of Duncan Energy Partners:		
Third-party owners of Duncan Energy Partners (2)	281.1	288.6
Joint venture partners (3)	148.0	141.8
AOCI attributable to noncontrolling interest	(50.3)	(45.2)
Total noncontrolling interest on consolidated balance sheet	$ 3,206.4	$ 2,882.2

(1) Represents former ownership interests in TEPPCO and TEPPCO GP (see Note 1 "Basis of Financial Statement Presentation"). This amount excludes AOCI attributable to former owners of TEPPCO.
(2) Consists of non-affiliate public unitholders of Duncan Energy Partners. On February 5, 2007, Duncan Energy Partners completed its initial public offering of 14,950,000 common units. A wholly owned operating subsidiary of ours owns the general partner of Duncan Energy Partners; therefore, we consolidate the financial statements of Duncan Energy Partners with those of our own. For financial accounting and reporting purposes, the public owners of Duncan Energy Partners are presented as noncontrolling interest in our supplemental consolidated financial statements effective February 1, 2007.
(3) Represents third-party ownership interests in joint ventures that we consolidate, including Seminole, Dixie, Tri-States Pipeline L.L.C. ("Tri-States"), Independence Hub LLC ("Independence Hub"), Wilprise Pipeline Company LLC ("Wilprise") and Belle Rose NGL Pipeline L.L.C. ("Belle Rose").

The following table presents the components of net income attributable to noncontrolling interest as presented on our Supplemental Statements of Consolidated Operations for the periods indicated:

	For Year Ended December 31,		
	2008	**2007**	**2006**
Former owners of TEPPCO (1)	$ 193.6	$ 273.8	$ 177.4
Limited partners of Duncan Energy Partners (2)	17.3	13.9	--
Joint venture partners	24.0	16.7	9.1
Total	$ 234.9	$ 304.4	$ 186.5

(1) Represents the allocation of earnings to the former owners of TEPPCO.
(2) Represents the allocation of Duncan Energy Partners earnings to its third party unitholders. Duncan Energy Partners completed its initial public offering in February 2007.

The following table presents cash distributions paid to and cash contributions from noncontrolling interests as presented on our Supplemental Statements of Consolidated Cash Flows for the periods indicated:

	For Year Ended December 31,		
	2008	2007	2006
Cash distributions paid to noncontrolling interests:			
Former owners of TEPPCO	$ 328.0	$ 294.4	$ 278.6
Limited partners of Duncan Energy Partners	24.8	15.8	--
Joint venture partners	31.1	16.6	8.8
Total cash distributions paid to noncontrolling interests	$ 383.9	$ 326.8	$ 287.4
Cash contributions from noncontrolling interests:			
Former owners of TEPPCO	$ 275.9	$ 1.7	$ 195.1
Limited partners of Duncan Energy Partners	--	290.5	--
Joint venture partners	35.6	12.5	27.5
Total cash contributions from noncontrolling interests	$ 311.5	$ 304.7	$ 222.6

Distributions paid to the former owners of TEPPCO and limited partners of Duncan Energy Partners primarily represent the quarterly cash distributions paid by these entities to their unitholders.

Contributions from the former owners of TEPPCO and limited partners of Duncan Energy Partners primarily represent proceeds each entity received from common unit offerings. In September 2008, TEPPCO sold 9.2 million of its common units in an underwritten equity offering, which generated net proceeds of $257.0 million. In February 2007, Duncan Energy Partners received approximately $291.0 million of net proceeds in connection with its initial public offering.

Note 16. Business Segments

As previously mentioned in Note 1, we revised our business segments and related disclosures as a result of the TEPPCO Merger. We have five reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Onshore Crude Oil Pipelines & Services, Offshore Pipelines & Services and Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold. The following information summarizes the principal operations and activities of each of our new business segments:

§ *NGL Pipelines & Services* includes our (i) natural gas processing business and related NGL marketing activities; (ii) NGL pipelines, including our Mid-America Pipeline System; (iii) NGL and related product storage facilities; and (iv) NGL fractionation facilities. This segment also includes our import and export terminal operations.

§ *Onshore Natural Gas Pipelines & Services* includes our onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. We own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our natural gas marketing activities.

§ *Onshore Crude Oil Pipelines & Services* business segment includes our onshore crude oil pipelines and related storage terminals. This segment also includes our related crude oil marketing activities.

§ *Offshore Pipelines & Services* includes our (i) offshore natural gas pipelines strategically located to serve production areas including some of the most active drilling and development regions in the Gulf of Mexico, (ii) offshore Gulf of Mexico crude oil pipeline systems and (iii) six multi-purpose offshore hub platforms located in the Gulf of Mexico with crude oil or natural gas processing capabilities.

§ *Petrochemical & Refined Products Services* includes our (i) propylene fractionation plants and related activities, (ii) butane isomerization facilities, (iii) octane enhancement facility, (iv) refined products pipelines, including our Products Pipeline System, and related activities and (v) marine transportation assets and other services.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before: (i) depreciation, amortization and accretion expense; (ii) non-cash impairment charges; (iii) operating lease expenses for which we do not have the payment obligation; (iv) gains and losses from asset sales and related transactions; and (v) general and administrative costs. Gross operating margin excludes other income and expense transactions, provision for income taxes, cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis and does not adjust for earnings attributable to noncontrolling interests. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of intercompany (both intersegment and intrasegment) transactions.

We include equity in earnings of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. In general, hydrocarbons enter our asset system in a number of ways, such as an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an onshore natural gas gathering pipeline, an NGL fractionator, an NGL storage facility, or an NGL transportation or distribution pipeline.

Many of our equity investees are included within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas, refined products and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process mixed NGLs extracted by our gas plants. The fractionated NGLs we receive from Promix can then be sold in our NGL marketing activities. Additionally, our use of the Centennial Pipeline, which loops our Products Pipeline System between Beaumont, Texas and southern Illinois, permits effective supply of product to points south of Illinois as well as incremental product supply capacity to midcontinent markets downstream of southern Illinois. Given the integral nature of our equity method investees to our operations, we believe the presentation of earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Historically, substantially all of our consolidated revenues were earned in the United States and derived from a wide customer base. The majority of our plant-based operations are located in Texas, Louisiana, Mississippi, New Mexico, Colorado and Wyoming. Our natural gas, NGL, refined products and crude oil pipelines are located in a number of regions of the United States including (i) the Gulf of Mexico offshore Texas, Louisiana, and onshore in Colorado; (ii) the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); (iii) the Midwestern and northeastern United States; and (iv) certain regions of the central and western United States, including the Rocky Mountains. Our marketing activities are headquartered in Houston, Texas and Oklahoma City, Oklahoma and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in unconsolidated affiliates are assigned to each segment on the basis of each asset's or investment's principal operations. The principal reconciling difference between consolidated property, plant and equipment and the total value of segment assets is construction in progress. Segment assets represent the net book carrying value of facilities and other assets that contribute to gross operating margin of that particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets are excluded from segment asset totals until they are placed in service. Consolidated intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate.

We consolidate the financial statements of Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include 100% of the gross operating margin amounts of Duncan Energy Partners.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
Revenues (1)	$ 35,469.6	$ 26,713.8	$ 23,612.1
Less: Operating costs and expenses (1)	(33,618.9)	(25,402.1)	(22,420.3)
Add: Equity in earnings of unconsolidated affiliates (1)	34.9	10.5	25.2
Depreciation, amortization and accretion in operating costs and expenses (2)	725.4	647.9	556.9
Operating lease expenses paid by EPCO (2)	2.0	2.1	2.1
Gain from asset sales and related transactions in operating costs and expenses (2)	(4.0)	(7.8)	(5.1)
Total segment gross operating margin	$ 2,609.0	$ 1,964.4	$ 1,770.9

(1) These amounts are taken from our Supplemental Statements of Consolidated Operations.
(2) These non-cash expenses are taken from the operating activities section of our Supplemental Statements of Consolidated Cash Flows. The 2007 period excludes the gain we recognized in connection with the sale of our MB Storage assets of approximately $60 million, which is included in other income in our Supplemental Statement of Consolidated Operations for the year ended December 31, 2007.

The following table shows a reconciliation of our total segment gross operating margin to operating income and income before provision for income taxes and the cumulative effect of change in accounting principle follows:

	For the Year Ended December 31,		
	2008	2007	2006
Total segment gross operating margin	$ 2,609.0	$ 1,964.4	$ 1,770.9
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(725.4)	(647.9)	(556.9)
Operating lease expense paid by EPCO	(2.0)	(2.1)	(2.1)
Gain from asset sales and related transactions in operating costs and expenses	4.0	7.8	5.1
General and administrative costs	(137.2)	(127.2)	(95.9)
Operating income	1,748.4	1,195.0	1,121.1
Other expense, net	(528.5)	(341.3)	(313.0)
Income before provision for income taxes and the cumulative effect of change in accounting principle	$ 1,219.9	$ 853.7	$ 808.1

Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Reportable Segments						
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:							
Year ended December 31, 2008	$ 14,715.8	$ 3,407.2	$ 12,763.8	$ 260.3	$ 3,307.1	$ --	$ 34,454.2
Year ended December 31, 2007	12,149.2	2,044.0	9,103.7	222.6	2,609.1	--	26,128.6
Year ended December 31, 2006	10,128.3	1,614.9	9,049.1	145.8	2,313.3	--	23,251.4
Revenues from related parties:							
Year ended December 31, 2008	598.0	409.2	--	8.1	0.1	--	1,015.4
Year ended December 31, 2007	301.5	281.9	0.1	1.2	0.5	--	585.2
Year ended December 31, 2006	67.7	291.0	1.8	--	0.2	--	360.7
Intersegment and intrasegment revenues:							
Year ended December 31, 2008	8,091.7	881.6	75.1	1.4	663.3	(9,713.1)	--
Year ended December 31, 2007	5,436.3	205.5	48.6	2.0	522.6	(6,215.0)	--
Year ended December 31, 2006	4,192.6	132.6	37.8	1.7	389.5	(4,754.2)	--
Total revenues:							
Year ended December 31, 2008	23,405.5	4,698.0	12,838.9	269.8	3,970.5	(9,713.1)	35,469.6
Year ended December 31, 2007	17,887.0	2,531.4	9,152.4	225.8	3,132.2	(6,215.0)	26,713.8
Year ended December 31, 2006	14,388.6	2,038.5	9,088.7	147.5	2,703.0	(4,754.2)	23,612.1
Equity in earnings of unconsolidated affiliates:							
Year ended December 31, 2008	1.4	1.6	11.7	33.7	(13.5)	--	34.9
Year ended December 31, 2007	7.1	0.2	2.6	12.7	(12.1)	--	10.5
Year ended December 31, 2006	14.9	2.6	11.9	11.8	(16.0)	--	25.2
Gross operating margin:							
Year ended December 31, 2008	1,325.0	589.9	132.2	187.0	374.9	--	2,609.0
Year ended December 31, 2007	848.0	493.2	109.6	171.6	342.0	--	1,964.4
Year ended December 31, 2006	785.7	478.9	97.8	103.4	305.1	--	1,770.9
Segment assets:							
At December 31, 2008	5,622.4	5,223.6	386.9	1,394.5	2,090.0	2,015.4	16,732.8
At December 31, 2007	4,770.4	4,577.4	363.7	1,452.6	1,556.7	1,588.3	14,309.1
At December 31, 2006	3,456.8	4,160.9	303.0	734.6	1,253.9	2,213.3	12,122.5
Investments in unconsolidated affiliates (see Note 11):							
At December 31, 2008	144.3	25.9	186.2	469.0	86.5	--	911.9
At December 31, 2007	117.0	3.5	184.8	484.6	95.7	--	885.6
Intangible assets, net (see Note 13):							
At December 31, 2008	351.4	584.4	6.9	116.2	124.0	--	1,182.9
At December 31, 2007	375.1	636.5	7.3	133.0	62.2	--	1,214.1
Goodwill (see Note 13):							
At December 31, 2008	341.2	284.9	303.0	82.1	1,008.4	--	2,019.6
At December 31, 2007	226.0	284.9	303.0	82.1	917.3	--	1,813.3

Our revenues are derived from a wide customer base. During 2008, 2007 and 2006, our largest customer was Valero Energy Corporation and its affiliates, which accounted for 11.2%, 8.9% and 9.3%, respectively, of our revenues.

On January 6, 2009, LyondellBasell Industries ("LBI") announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. LBI accounted for 5.9% of our consolidated revenues during 2008. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. In addition, we are seeking to have LBI accept certain contracts and have filed claims pursuant to current Bankruptcy Court Orders that we expect will allow us to recover the majority of the remaining credit exposure.

The following table provides additional information regarding our consolidated revenues (net of adjustments and eliminations) and expenses for the periods noted:

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services:			
Sales of NGLs	$ 14,573.5	$ 11,701.3	$ 9,429.2
Sales of other petroleum and related products	2.4	3.0	2.4
Midstream services	737.9	746.4	764.4
Total	15,313.8	12,450.7	10,196.0
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	3,089.4	1,481.6	1,103.1
Midstream services	727.0	844.3	802.8
Total	3,816.4	2,325.9	1,905.9
Onshore Crude Oil Pipelines & Services:			
Sales of crude oil	12,696.2	9,048.5	9,002.7
Midstream services	67.6	55.3	48.2
Total	12,763.8	9,103.8	9,050.9
Offshore Pipelines & Services:			
Sales of natural gas	2.8	3.2	2.1
Sales of other petroleum and related products	11.1	12.1	4.5
Midstream services	254.5	208.5	139.2
Total	268.4	223.8	145.8
Petrochemical & Refined Products Services:			
Sales of other petroleum and related products	2,757.6	2,207.2	1,938.9
Midstream services	549.6	402.4	374.6
Total	3,307.2	2,609.6	2,313.5
Total consolidated revenues	$ 35,469.6	$ 26,713.8	$ 23,612.1
Consolidated cost and expenses			
Operating costs and expenses:			
Cost of sales	$ 28,107.0	$ 21,006.0	$ 18,574.2
Depreciation, amortization and accretion	725.4	647.9	556.9
Gain on sale of assets and related transactions	(4.0)	(7.8)	(5.1)
Other operating costs and expenses	4,790.5	3,756.0	3,294.3
General and administrative costs	137.2	127.2	95.9
Total consolidated costs and expenses	$ 33,756.1	$ 25,529.3	$ 22,516.2

Note 17. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated.

	For the Year Ended December 31,		
	2008	2007	2006
Revenues from consolidated operations			
EPCO and affiliates	$ --	$ 0.2	$ 55.8
Energy Transfer Equity and subsidiaries	618.5	294.5	--
Unconsolidated affiliates	396.9	290.5	304.9
Total	$ 1,015.4	$ 585.2	$ 360.7
Cost of sales			
EPCO and affiliates	$ 40.1	$ 34.0	$ 75.3
Energy Transfer Equity and subsidiaries	173.9	26.9	--
Unconsolidated affiliates	58.6	41.0	45.2
Total	$ 272.6	$ 101.9	$ 120.5
Operating costs and expenses			
EPCO and affiliates	$ 423.1	$ 353.7	$ 328.5
Energy Transfer Equity and subsidiaries	18.3	8.3	--
Cenac and affiliates	45.4	--	--
Unconsolidated affiliates	(2.4)	--	(5.2)
Total	$ 484.4	$ 362.0	$ 323.3
General and administrative expenses			
EPCO and affiliates	$ 91.0	$ 82.6	$ 63.7
Cenac and affiliates	2.9	--	--
Unconsolidated affiliates	(0.1)	--	--
Total	$ 93.8	$ 82.6	$ 63.7
Other income (expense)			
EPCO and affiliates	$ (0.3)	$ (0.2)	$ 0.7
Unconsolidated affiliates	--	--	0.3
Total	$ (0.3)	$ (0.2)	$ 1.0

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Relationship with EPCO and affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not a part of our consolidated group of companies:

§ EPCO and its private company subsidiaries;

§ EPGP, our sole general partner;

§ Enterprise GP Holdings, which owns and controls our general partner; and

§ the Employee Partnerships (see Note 5).

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with those of our own. Our transactions with Duncan Energy Partners are eliminated in the preparation of our consolidated financial statements. A description of our relationship with Duncan Energy Partners is presented within this Note 17.

EPCO is a private company controlled by Dan L. Duncan, who is also a Director and Chairman of EPGP, our general partner. At December 31, 2008, EPCO and its affiliates beneficially owned 152,506,527 (or 34.5%) of our outstanding common units, which includes 13,670,925 of our common units owned by Enterprise GP Holdings. At December 31, 2008, EPCO and affiliates beneficially owned

17,073,315 (or 16.3%) of TEPPCO's common units, including 4,400,000 common units owned by Enterprise GP Holdings. In addition, at December 31, 2008, EPCO and its affiliates beneficially owned 77.8% of the limited partner interests of Enterprise GP Holdings and 100% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of EPGP and TEPPCO GP. The principal business activity of EPGP is to act as our managing partner. The principal business activity of TEPPCO GP is to act as the sole general partner of TEPPCO. The executive officers and certain of the directors of EPGP, TEPPCO GP and EPE Holdings are employees of EPCO.

As our general partner, EPGP received cash distributions of $144.1 million, $124.4 million and $101.8 million from us during the years ended December 31, 2008, 2007 and 2006, respectively. These amounts include incentive distributions of $125.9 million, $107.4 million and $86.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

We and EPGP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its private company subsidiaries depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its private company affiliates received $439.8 million, $388.9 million and $306.5 million in cash distributions from us and Enterprise GP Holdings during the years ended December 31, 2008, 2007 and 2006, respectively.

The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a private company affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, TEPPCO and us.

We have entered into an agreement with an affiliate of EPCO to provide trucking services to us for the transportation of NGLs and other products. For the years ended December 31, 2008, 2007 and 2006, we paid this trucking affiliate $21.7 million, $19.1 million and $20.7 million, respectively, for such services.

We lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates. For the years ended December 31, 2008, 2007 and 2006, we paid EPCO $7.8 million, $7.8 million and $3.7 million, respectively, for office space leases.

Historically, we entered into transactions with a Canadian affiliate of EPCO for the purchase and sale of NGL products in the normal course of business. These transactions were at market-related prices. We acquired this affiliate in October 2006 and began consolidating its financial statements with those of our own from the date of acquisition. For the nine months ended September 30, 2006, our revenues from this former unconsolidated affiliate were $55.8 million and our purchases were $43.4 million.

EPCO ASA

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA or by other service providers. We, Duncan Energy Partners, Enterprise GP Holdings and our respective general partners are parties to the ASA. The significant terms of the ASA are as follows:

§ EPCO will provide selling, general and administrative services, and management and operating services, as may be necessary to manage and operate our businesses, properties and assets (all 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 expenses reasonably allocated to us by EPCO). 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 will allow us to participate as a named insured in its overall insurance program, with the associated premiums and other costs being allocated to us.

Under the ASA, EPCO subleases to us (for $1 per year) certain equipment which it holds pursuant to operating leases and has assigned to us its purchase option under such leases (the "retained leases"). EPCO remains liable for the actual cash lease payments associated with these agreements. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to equity accounted for as a general contribution to our partnership. We exercised our election under the retained leases to purchase a cogeneration unit in December 2008 for $2.3 million. Should we decide to exercise the purchase option associated with the remaining agreement, we would pay the original lessor $3.1 million in June 2016.

Our operating costs and expenses for the years ended December 31, 2008, 2007 and 2006 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. These reimbursements were $461.2 million, $385.5 million and $401.7 million during the years ended December 31, 2008, 2007 and 2006, respectively.

Likewise, our general and administrative costs for the years ended December 31, 2008, 2007 and 2006 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 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). These reimbursements were $91.0 million, $82.4 million and $63.4 million during the years ended December 31, 2008, 2007 and 2006, respectively.

Since the vast majority of such expenses are charged to us on an actual basis (i.e. no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a stand alone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a stand alone basis.

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), and the EPCO Group with respect to business opportunities with third parties. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners. With respect to potential conflicts with respect to third party business opportunities, the ASA provides, among other things, that:

- § If a business opportunity to acquire "equity securities" (as defined below) is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), then Enterprise GP Holdings will have the first right to pursue such opportunity. The term "equity securities" is defined to include:

  - § general partner interests (or securities which have characteristics similar to general partner interests) or interests in "persons" that own or control such general partner or similar interests (collectively, "GP Interests") and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

- § IDRs and limited partner interests (or securities which have characteristics similar to IDRs or limited partner interests) in publicly traded partnerships or interests in "persons" that own or control such limited partner or similar interests (collectively, "non-GP Interests"); provided that such non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

Enterprise GP Holdings will be presumed to want to acquire the equity securities until such time as EPE Holdings advises the EPCO Group, EPGP and DEP GP that it has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to equal or exceed $100.0 million, the decision to decline the acquisition will be made by the chief executive officer of EPE Holdings after consultation with and subject to the approval of the ACG Committee of EPE Holdings. If the purchase price is reasonably likely to be less than $100.0 million, the chief executive officer of EPE Holdings may make the determination to decline the acquisition without consulting the ACG Committee of EPE Holdings.

In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, EPGP and DEP GP, Enterprise Products Partners will have the second right to pursue such acquisition. Enterprise Products Partners will be presumed to want to acquire the equity securities until such time as EPGP advises the EPCO Group and DEP GP that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to Enterprise GP Holdings, as described above but utilizing EPGP's chief executive officer and ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

- § If any business opportunity not covered by the preceding bullet point (i.e. not involving equity securities) is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), or Duncan Energy Partners (including DEP GP), Enterprise Products Partners will have the first right to pursue such opportunity either for itself or, if desired by Enterprise Products Partners in its sole discretion, for the benefit of Duncan Energy Partners. It will be presumed that Enterprise Products Partners will pursue the business opportunity until such time as its general partner advises the EPCO Group, EPE Holdings and DEP GP that it has abandoned the pursuit of such business opportunity.

In the event the purchase price or cost associated with the business opportunity is reasonably likely to equal or exceed $100.0 million, any decision to decline the business opportunity will be made by the chief executive officer of EPGP after consultation with and subject to the approval of the ACG Committee of EPGP. If the purchase price or cost is reasonably likely to be less than $100.0 million, the chief executive officer of EPGP may make the determination to decline the business opportunity without consulting EPGP's ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event that Enterprise Products Partners abandons the business opportunity for itself and Duncan Energy Partners and so notifies the EPCO Group, EPE Holdings and DEP GP, Enterprise GP Holdings will have the second right to pursue such business opportunity. It will be presumed that Enterprise GP Holdings will pursue such acquisition until such time as its general partner declines such opportunity (in accordance with the procedures described above for Enterprise Products Partners) and advises the EPCO Group that it has abandoned the pursuit of such business opportunity.

The ASA was amended on January 30, 2009 to provide for the cash reimbursement by us and Enterprise GP Holdings to EPCO of distributions of cash or securities, if any, made by EPCO Unit to its Class B limited partners. The ASA amendment also extended the term under which EPCO provides services to the partnership entities from December 2010 to December 2013 and made other updating and conforming changes.

Employee Partnerships

EPCO formed the Employee Partnerships to serve as an incentive arrangement for key employees of EPCO by providing them a "profits interest" in such partnerships. Certain EPCO employees who work on behalf of us and EPCO were issued Class B limited partner interests and admitted as Class B limited partners without any capital contribution. The profits interest awards (i.e., the Class B limited partner interests) in the Employee Partnerships entitles each holder to participate in the appreciation in value of EPE common units, TEPPCO units and our common units. See Note 5 for additional information regarding the Employee Partnerships.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

For the year ended December 31, 2008 and the eight months ended December 31, 2007, we recorded $618.4 million and $294.4 million, respectively, of revenues from Energy Transfer Partners, L.P. ("ETP"), primarily from NGL marketing activities. We incurred $192.2 million and $35.2 million in costs of sales and operating costs and expenses for the year ended December 31, 2008 and the eight months ended December 31, 2007, respectively. We have a long-term revenue generating contract with Titan Energy Partners, L.P. ("Titan"), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract continues until March 31, 2010 and contains renewal and extension options. We and Energy Transfer Company ("ETC OLP") transport natural gas on each other's systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

Relationship with Duncan Energy Partners

Duncan Energy Partners was formed in September 2006 and did not acquire any assets prior to February 5, 2007, which was the date it completed its initial public offering of 14,950,000 common units and acquired controlling interests in certain midstream energy businesses of EPO. The business purpose of Duncan Energy Partners is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates under common control. Duncan Energy Partners is engaged in (i) the gathering, transportation and storage of natural gas; (ii) NGL transportation and fractionation; (iii) the storage of NGL and petrochemical products; (iv) the transportation of petrochemical products; and (v) the marketing of NGLs and natural gas.

At December 31, 2008, Duncan Energy Partners is owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP OLP, a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business.

At December 31, 2008, EPO owned approximately 74% of Duncan Energy Partners' limited partner interests and 100% of its general partner.

DEP I Midstream Businesses

On February 5, 2007, EPO contributed a 66% controlling equity interest in each of the DEP I Midstream Businesses (defined below) to Duncan Energy Partners in a dropdown of assets (the "DEP I dropdown"). EPO retained the remaining 34% equity interest in each of the DEP I Midstream Businesses.

The DEP I Midstream Businesses consist of (i) Mont Belvieu Caverns, LLC (“Mont Belvieu Caverns”); (ii) Acadian Gas, LLC (“Acadian Gas”); (iii) Enterprise Lou-Tex Propylene Pipeline L.P. (“Lou-Tex Propylene”), including its general partner; (iv) Sabine Propylene Pipeline L.P. (“Sabine Propylene’), including its general partner; and (v) South Texas NGL Pipelines, LLC (“South Texas NGL”).

As consideration for controlling equity interests in the DEP I Midstream Businesses and reimbursement for capital expenditures related to these businesses, Duncan Energy Partners distributed to EPO (i) $260.6 million of the $290.5 million of net proceeds from its initial public offering, (ii) $198.9 million in borrowings under its DEP I Revolving Credit Facility and (iii) a net 5,351,571 common units of Duncan Energy Partners. See Note 14 for information regarding the debt obligations of Duncan Energy Partners.

DEP II Midstream Businesses

On December 8, 2008, Duncan Energy Partners entered into the DEP II Purchase Agreement with EPO and Enterprise GTM, a wholly owned subsidiary of EPO. Pursuant to the DEP II Purchase Agreement, DEP OLP acquired 100% of the membership interests in Enterprise III from Enterprise GTM, thereby acquiring a 66% general partner interest in Enterprise GC, a 51% general partner interest in Enterprise Intrastate and a 51% membership interest in Enterprise Texas. Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the “DEP II Midstream Businesses.” EPO was the sponsor of this second dropdown transaction (the “DEP II dropdown”). Enterprise GTM retained the remaining limited partner and member interests in the DEP II Midstream Businesses.

As consideration for controlling equity interests in the DEP II Midstream Businesses, EPO received $280.5 million in cash and 37,333,887 Class B limited partner units having a market value of $449.5 million from Duncan Energy Partners. The Class B limited partner units automatically converted to common units of Duncan Energy Partners on February 1, 2009. The total value of the consideration provided to EPO and Enterprise GTM was $730.0 million. The cash portion of the consideration provided by Duncan Energy Partners in this dropdown transaction was derived from borrowings under the DEP II Term Loan Agreement. See Note 14 for information regarding the debt obligations of Duncan Energy Partners.

Generally, the DEP II dropdown transaction documents provide that to the extent that the DEP II Midstream Businesses generate cash sufficient to pay distributions to their partners or members, such cash will be distributed to Enterprise III (a wholly owned subsidiary of Duncan Energy Partners) and Enterprise GTM (our wholly owned subsidiary) in an amount sufficient to generate an aggregate annualized return on their respective investments of 11.85%. Distributions in excess of this amount will be distributed 98% to Enterprise GTM and 2% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102% of 11.85%, or 12.087%.

Duncan Energy Partners paid a pro rated cash distribution of $0.1115 per unit on the Class B units with respect to the fourth quarter of 2008.

The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

We may contribute other equity interests in our subsidiaries to Duncan Energy Partners and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program.

Omnibus Agreement

On December 8, 2008, we entered into an amended and restated Omnibus Agreement with Duncan Energy Partners. The key provisions of this agreement are summarized as follows:

- indemnification for certain environmental liabilities, tax liabilities and right-of-way defects with respect to the DEP I and DEP II Midstream Businesses we contributed to Duncan Energy Partners in connection with the respective dropdown transactions;
- funding by EPO of 100% of post-February 5, 2007 capital expenditures incurred by South Texas NGL and Mont Belvieu Caverns with respect to certain expansion projects under construction at the time of Duncan Energy Partners' initial public offering;
- funding by EPO of 100% of post-December 8, 2008 capital expenditures (estimated at $1.4 million) to complete the Sherman Extension natural gas pipeline;
- a right of first refusal to EPO in our current and future subsidiaries and a right of first refusal on the material assets of such subsidiaries, other than sales of inventory and other assets in the ordinary course of business; and
- a preemptive right with respect to equity securities issued by certain of our subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

We and Duncan Energy Partners have also agreed to negotiate in good faith any necessary amendments to the partnership or company agreements of the DEP II Midstream Businesses when either party believes that business circumstances have changed.

Our general partner's ACG Committee must approve amendments to the Omnibus Agreement when such amendments would adversely affect our unitholders.

EPO has indemnified Duncan Energy Partners against certain environmental liabilities, tax liabilities and right-of-way defects associated with the assets EPO contributed to Duncan Energy Partners in connection with the DEP I and DEP II dropdown transactions. These liabilities include both known and unknown environmental and related liabilities. These indemnifications terminate on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage, and Duncan Energy Partners is not entitled to indemnification until the aggregate amount of claims it incurs exceeds $250 thousand. Environmental liabilities resulting from a change of law after February 5, 2007 are excluded from the indemnity. In addition, EPO has indemnified Duncan Energy Partners for liabilities related to:

- certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to Duncan Energy Partners in connection with its initial public offering are located and failure to obtain certain consents and permits necessary to conduct its business that arise through February 5, 2010; and
- certain income tax liabilities attributable to the operation of the assets contributed to Duncan Energy Partners in connection with its initial public offering prior to February 5, 2007.

The Omnibus Agreement may not be amended without the prior approval of the ACG Committee if the proposed amendment will, in the reasonable discretion of DEP GP, adversely affect holders of its common units.

Neither we, nor EPO and any of its affiliates are restricted under the Omnibus Agreement from competing with Duncan Energy Partners. Except as otherwise expressly agreed in the ASA, EPO and any of its affiliates may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer Duncan Energy Partners the opportunity to purchase or construct those assets. These agreements are in addition to other agreements relating to business opportunities and potential conflicts of interest set forth in the ASA with EPO, EPCO and other affiliates of EPCO.

Under the Omnibus Agreement, EPO agreed to make additional contributions to Duncan Energy Partners as reimbursement for Duncan Energy Partners' 66% share of any excess construction costs above the (i) $28.6 million of estimated capital expenditures to complete Phase II expansions of the DEP South Texas NGL Pipeline System and (ii) $14.1 million of estimated construction costs for additional brine production capacity and above-ground storage reservoir projects at Mont Belvieu, Texas. Both projects were underway at the time of Duncan Energy Partners' initial public offering. EPO made cash contributions to Duncan Energy Partners of $32.5 million and $9.9 million in connection with the Omnibus Agreement during the years ended December 31, 2008 and 2007, respectively. The majority of these contributions related to funding the Phase II expansion costs of the DEP South Texas NGL Pipeline System. EPO will not receive an increased allocation of earnings or cash flows as a result of these contributions to South Texas NGL and Mont Belvieu Caverns.

Mont Belvieu Caverns' LLC Agreement

The Mont Belvieu Caverns' LLC Agreement (the "Caverns LLC Agreement") states that if Duncan Energy Partners elects to not participate in certain projects of Mont Belvieu Caverns, then EPO is responsible for funding 100% of such projects. To the extent such non-participated projects generate identifiable incremental cash flows for Mont Belvieu Caverns in the future, the earnings and cash flows of Mont Belvieu Caverns will be adjusted to allocate such incremental amounts to EPO by special allocation or otherwise. Under the terms of the Caverns LLC Agreement, Duncan Energy Partners may elect to acquire a 66.0% share of these projects from EPO within 90 days of such projects being placed in service.

EPO made cash contributions of $99.5 million and $38.1 million under the Caverns LLC Agreement during the years ended December 31, 2008 and 2007, respectively, to fund 100% of certain storage-related projects for the benefit of EPO's NGL marketing activities. At present, Mont Belvieu Caverns is not expected to generate any identifiable incremental cash flows in connection with these projects; thus, the sharing ratio for Mont Belvieu Caverns is not expected to change from the current sharing ratio of 66% for Duncan Energy Partners and 34% for EPO. EPO expects to make additional contributions of approximately $27.5 million to fund such projects in 2009. The constructed assets will be the property of Mont Belvieu Caverns.

In November 2008, the Caverns LLC Agreement was amended to provide that EPO would prospectively receive a special allocation of 100% of the depreciation related to projects that it has fully funded.   For the two-month period in 2008 covered by the amendment, EPO was allocated depreciation expense of $1.0 million related to such projects.

The Caverns LLC Agreement also requires the allocation to EPO of operational measurement gains and losses. Operational measurement gains and losses are created when product is moved between storage wells and are attributable to pipeline and well connection measurement variances.

Company and Limited Partnership Agreements – DEP II Midstream Businesses

On December 8, 2007, the DEP II Midstream Businesses amended and restated their governing documents in connection with the DEP II dropdown transaction. Collectively, these amended and restated agreements provide for the following:

§ the acquisition by Enterprise III (a wholly owned subsidiary of Duncan Energy Partners) from Enterprise GTM (our wholly owned subsidiary) of a 66% general partner interest in Enterprise GC, a 51% general partner interest in Enterprise Intrastate and a 51% member interest in Enterprise Texas;

§ the payment of distributions in accordance with an overall "waterfall" approach that stipulates that to the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to their partners or members, such cash will be distributed first to Enterprise III (based on an initial defined investment of $730.0 million, the "Enterprise III Distribution Base") and then to Enterprise GTM (based on an initial defined investment of $452.1 million, the "Enterprise GTM Distribution Base") in amounts sufficient to generate an aggregate annualized fixed return on their respective investments of 11.85%. Distributions in excess of these amounts will be distributed 98% to Enterprise GTM and 2.0% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2.0% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102% of 11.85%, or 12.087%;

§ the funding of operating cash flow deficits in accordance with each owner's respective partner or member interest; and

§ the election by either owner to fund cash calls associated with expansion capital projects. Since December 8, 2008, Enterprise III has elected to not participate in such cash calls and, as a result, Enterprise GTM has funded 100% of the expansion project costs of the DEP II Midstream Businesses. If Enterprise III later elects to participate in an expansion projects, then Enterprise III will be required to make a capital contribution for its share of the project costs.

Any capital contributions to fund expansion projects made by either Enterprise III or Enterprise GTM will increase such partner's Distribution Base (and hence future priority return amounts) under the Company Agreement of Enterprise Texas. As noted, Enterprise III has declined participation in expansion project spending since December 8, 2008. As a result, Enterprise GTM has funded 100% of such growth capital spending and its Distribution Base has increased from $452.1 million at December 8, 2008 to $473.4 million at December 31, 2008. The Enterprise III Distribution Base was unchanged at $730.0 million at December 31, 2008.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. See Note 16 for a discussion of this alignment of commercial interests. Since we and our affiliates hold ownership interests in these entities and directly or indirectly benefit from our related party transactions with such entities, they are presented here.

The following information summarizes significant related party transactions with our current unconsolidated affiliates:

§ We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. Revenues from Evangeline were $362.9 million, $268.0 million and $277.7 million for the years ended December 31, 2008, 2007 and 2006. In addition, Duncan Energy Partners furnished $1.0 million in letters of credit on behalf of Evangeline at December 31, 2008.

§ We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Revenues from Promix were $24.5 million, $17.3 million and $21.8 million, respectively, for the years ended December 31, 2008, 2007 and 2006. Expenses with Promix were $38.7 million, $30.4 million and $34.9 million for the years ended December 31, 2008, 2007 and 2006, respectively.

§ For the years ended December 31, 2008, 2007 and 2006, we paid $1.7 million, $3.8 million and $5.6 million, respectively, to Centennial in connection with a pipeline capacity lease. In addition, we paid $6.6 million and $5.3 million to Centennial for the year ended December 31, 2008 and 2007 for other pipeline transportation services, respectively.

- § For the years ended December 31, 2008, 2007 and 2006, we paid Seaway $6.0 million, $4.7 million and $3.8 million, respectively, for transportation and tank rentals in connection with our crude oil marketing activities.

- § We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $11.2 million, $11.0 million and $10.3 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Relationship with Cenac

In connection with our marine services acquisition in February 2008, Cenac and affiliates became a related party of ours due to its ownership of TEPPCO units through October 26, 2009, which then converted to our common units, and other considerations. We entered into a transitional operating agreement with Cenac in which our fleet of acquired tow boats and tank barges will continue to be operated by employees of Cenac for a period of up to two years following the acquisition. Under this agreement, we pay Cenac a monthly operating fee and reimburse Cenac for personnel salaries and related employee benefit expenses, certain repairs and maintenance expenses and insurance premiums on the equipment. During 2008, we paid Cenac approximately $48.3 million in connection with the transitional operating agreement.

Note 18. Provision for Income Taxes

Our provision for income taxes relates primarily to federal and state income taxes of Seminole and Dixie, our two largest corporations subject to such income taxes. In addition, with the amendment of the Texas Franchise Tax in 2006, we have become a taxable entity in the state of Texas. Our federal and state income tax provision is summarized below:

	For the Year Ended December 31,		
	2008	2007	2006
Current:			
Federal	$ 4.9	$ 4.7	$ 7.7
State	23.9	5.1	1.2
Foreign	0.4	0.1	--
Total current	29.2	9.9	8.9
Deferred:			
Federal	0.8	2.7	6.1
State	1.0	3.1	7.0
Foreign	--	--	--
Total deferred	1.8	5.8	13.1
Total provision for income taxes	$ 31.0	$ 15.7	$ 22.0

A reconciliation of the provision for income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income before income taxes is as follows:

	For the Year Ended December 31,		
	2008	2007	2006
Pre Tax Net Book Income ("NBI")	$ 1,219.9	$ 853.7	$ 808.1
Revised Texas franchise tax	23.9	7.7	8.8
State income taxes (net of federal benefit)	0.5	0.3	(0.4)
Federal income taxes computed by applying the federal statutory rate to NBI of corporate entities	6.3	5.3	13.4
Taxes charged to cumulative effect of change in accounting principle	--	--	--
Valuation allowance	(1.4)	2.3	0.1
Other permanent differences	1.7	0.1	0.1
Provision for income taxes	$ 31.0	$ 15.7	$ 22.0
Effective income tax rate	2.5%	1.8%	2.7%

Significant components of deferred tax assets and deferred tax liabilities as of December 31, 2008 and 2007 are as follows:

	December 31,	
	2008	2007
Deferred tax assets:		
Net operating loss carryovers	$ 26.3	$ 23.3
Property, plant and equipment	0.8	--
Credit carryover	--	--
Charitable contribution carryover	--	--
Employee benefit plans	2.6	3.2
Deferred revenue	1.0	0.6
Reserve for legal fees and damages	0.3	0.4
Equity investment in partnerships	0.6	0.4
AROs	0.1	0.1
Accruals	0.9	1.1
Total deferred tax assets	32.6	29.1
Valuation allowance	3.9	5.3
Net deferred tax assets	28.7	23.8
Deferred tax liabilities:		
Property, plant and equipment	92.9	40.5
Other	0.1	0.1
Total deferred tax liabilities	93.0	40.6
Total net deferred tax liabilities	(64.3)	(16.8)
Current portion of total net deferred tax assets	1.4	1.1
Long-term portion of total net deferred tax liabilities	$ (65.7)	$ (17.9)

We had net operating loss carryovers of $26.3 million and $23.3 million at December 31, 2008 and 2007, respectively. These losses expire in various years between 2009 and 2028 and are subject to limitations on their utilization. We record a valuation allowance to reduce our deferred tax assets to the amount of future tax benefit that is more likely than not to be realized. The valuation allowance was $3.9 million and $5.3 million at December 31, 2008 and 2007, respectively, and serves to reduce the recognized tax benefit associated with carryovers of our corporate entities to an amount that will, more likely than not, be realized. The $1.4 million decrease in valuation allowance for 2008 is comprised primarily of a $1.6 million decrease for Canadian Enterprise Gas Products, Ltd.

We have deferred tax liabilities on property plant and equipment of $92.9 million and $40.5 million at December 31, 2008 and 2007, respectively. The increase in 2008 is comprised primarily of $45.1 million related to the difference in book and tax basis of property, plant and equipment resulting from the acquisition of the remaining equity interest of Dixie Pipeline. See Note 12 for additional information.

On May 18, 2006, the State of Texas enacted House Bill 3 which revised the pre-existing state franchise tax. In general, legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax, including previously non-taxable entities such as limited liability companies, limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits.

Although the bill states that the Revised Texas Franchise Tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Due to the enactment of the Revised Texas Franchise Tax, we recorded a net deferred tax liability of $0.9 million and $3.1 million during the years ended December 31, 2008 and 2007, respectively. The offsetting net charge of $0.9 million and $3.1 million is shown on our Supplemental Statements of Consolidated Operations for the years ended December 31, 2008 and 2007, respectively, as a component of "Provision for income taxes."

Note 19. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss available to limited partner interests by the weighted-average number of distribution-bearing units outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss available to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of performance-based phantom units outstanding during a period; and (iii) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net losses, restricted units, phantom units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase common units at an average market value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

The amount of net income or loss available to limited partner interests is net of our general partner's share of such earnings. The following table presents the net income available to EPGP for the periods indicated:

	For The Year Ended December 31,		
	2008	2007	2006
Net income attributable to Enterprise Products Partners L.P.	$ 954.0	$ 533.6	$ 601.1
Less incentive earnings allocations to EPGP	(125.9)	(107.4)	(86.7)
Net income available after incentive earnings allocation	828.1	426.2	514.4
Multiplied by EPGP ownership interest	2.0%	2.0%	2.0%
Standard earnings allocation to EPGP	$ 16.6	$ 8.5	$ 10.3
Incentive earnings allocation to EPGP	$ 125.9	$ 107.4	$ 86.7
Standard earnings allocation to EPGP	16.6	8.5	10.3
Net income available to EPGP	142.5	115.9	97.0
Adjustment for EITF 07-4 (1)	5.2	4.5	6.0
Net income available to EPGP for EPU purposes	$ 147.7	$ 120.4	$ 103.0

(1) For purposes of computing basic and diluted earnings per unit, we used the provisions of EITF 07-4.

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated and does not include any pro forma impact relating to outstanding TEPPCO units:

	For The Year Ended December 31, 2008	2007	2006
BASIC EARNINGS PER UNIT			
Numerator			
Net income attributable to Enterprise Products Partners L.P.	$ 954.0	$ 533.6	$ 601.1
Net income available to EPGP for EPU purposes	(147.7)	(120.4)	(103.0)
Net income available to limited partners	$ 806.3	$ 413.2	$ 498.1
Denominator			
Common units	435.4	432.5	413.5
Time-vested restricted units	2.0	1.5	0.9
Total	437.4	434.0	414.4
Basic earnings per unit			
Net income per unit before EPGP earnings allocation	$ 2.18	$ 1.23	$ 1.45
Net income available to EPGP	(0.34)	(0.28)	(0.25)
Net income available to limited partners	$ 1.84	$ 0.95	$ 1.20
DILUTED EARNINGS PER UNIT			
Numerator			
Net income attributable to Enterprise Products Partners L.P.	$ 954.0	$ 533.6	$ 601.1
Net income available to EPGP for EPU purposes	(147.7)	(120.4)	(103.0)
Net income available to limited partners	$ 806.3	$ 413.2	$ 498.1
Denominator			
Common units	435.4	432.5	413.5
Time-vested restricted units	2.0	1.5	0.9
Performance-based restricted units	*	*	*
Incremental option units	0.2	0.4	0.3
Total	437.6	434.4	414.7
Diluted earnings per unit			
Net income per unit before EPGP earnings allocation	$ 2.18	$ 1.23	$ 1.45
Net income available to EPGP	(0.34)	(0.28)	(0.25)
Net income available to limited partners	$ 1.84	$ 0.95	$ 1.20

* Amount is negligible.

Note 20. Commitments and Contingencies

Litigation

On occasion, we or our unconsolidated affiliates are named as a defendant in litigation relating to our normal business activities, including regulatory and environmental matters. Although we are insured against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activities. We are unaware of any significant litigation, pending or threatened, that could have a significant 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 other unitholders of TEPPCO and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and us or our affiliates. Mr. Brinkerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants (i) TEPPCO, its current and certain former directors, and certain of its affiliates; (ii) us and certain of our affiliates; (iii) EPCO.; and (iv) Dan L. Duncan.

The amended complaint alleges, among other things, that the defendants caused TEPPCO to enter into certain transactions that were unfair to TEPPCO or otherwise unfairly favored Enterprise Products Partners or its affiliates over TEPPCO. These transactions are alleged to include: (i) the joint venture to further expand the Jonah system entered into by TEPPCO and Enterprise Products Partners in August 2006; (ii) the sale by TEPPCO of its Pioneer natural gas processing plant to Enterprise Products Partners in March 2006; and (iii) certain amendments to TEPPCO's partnership agreement, including a reduction in the maximum tier of TEPPCO's IDRs in exchange for TEPPCO units. The amended complaint seeks (i) rescission of the amendments to TEPPCO's partnership agreement; (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the amended complaint; and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. We believe this lawsuit is without merit and intend to vigorously defend against it.

On February 14, 2007, EPO received a letter from the Environment and Natural Resources Division ("ENRD") of the U.S. Department of Justice ("DOJ") related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third party, Magellan Ammonia Pipeline, L.P. ("Magellan") and a previous release of ammonia on September 27, 2004 from the same pipeline. EPO was the operator of this pipeline until July 1, 2008. The ENRD has indicated that it may pursue civil damages against EPO and Magellan as a result of these incidents. Based on this correspondence from the ENRD, the statutory maximum amount of civil fines that could be assessed against EPO and Magellan is up to $17.4 million in the aggregate. EPO is cooperating with the DOJ and is hopeful that an expeditious resolution of this civil matter acceptable to all parties will be reached in the near future. Magellan has agreed to indemnify EPO for the civil matter. At this time, we do not believe that a final resolution of the civil claims by the ENRD will have a material impact on our consolidated financial position, results of operations or cash flows.

On October 25, 2006, a rupture in the Magellan Ammonia Pipeline resulted in the release of ammonia near Clay Center, Kansas. The pipeline has been repaired and environmental remediation tasks related to this incident have been completed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position, results of operations or cash flows.

Several lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing methyl tertiary butyl ether ("MTBE"). In general, such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary that owns an octane-additive production facility. It is possible, however, that former MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

The Attorney General of Colorado on behalf of the Colorado Department of Public Health and Environment filed suit against us and others on April 15, 2008 in connection with the construction of a pipeline near Parachute, Colorado. The State sought a temporary restraining order and an injunction to halt construction activities since it alleged that the defendants failed to install measures to minimize damage to the environment and to follow requirements for the pipeline's stormwater permit and appropriate stormwater plan. The State's complaint also seeks penalties for the above alleged failures. Defendants and the State agreed to certain stipulations that, among other things, require us to install specified environmental protection measures in the disturbed pipeline right-of-way to comply with regulations. We have complied with the stipulations and the State has dismissed the portions of the complaint seeking the temporary restraining order and injunction. The State has not yet assessed penalties and we are unable to predict the amount of penalties that may be assessed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position, results of operations or cash flows.

In January 2009, the State of New Mexico filed suit in District Court in Santa Fe County, New Mexico, under the New Mexico Air Quality Control Act. The lawsuit arose out of a February 27, 2008 Notice Of Violation issued to Marathon as operator of the Indian Basin natural gas processing facility located in Eddy County, New Mexico. We own a 40.0% undivided interest in the assets comprising the Indian Basin facility. The State alleges violations of its air laws, and Marathon believes there has been no adverse impact to public health or the environment, having implemented voluntary emission reduction measures over the years. The State seeks penalties above $100,000. Marathon continues to work with the State to determine if resolution of the case is possible.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2008. A description of each type of contractual obligation follows.

	Payment or Settlement due by Period						
Contractual Obligations	**Total**	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**
Scheduled maturities of long-term debt	$ 11,562.8	$ --	$ 554.0	$ 934.3	$ 2,534.3	$ 1,200.0	$ 6,340.2
Estimated cash interest payments	$ 11,976.0	$ 691.5	$ 669.5	$ 618.1	$ 578.9	$ 457.6	$ 8,960.4
Operating lease obligations	$ 388.3	$ 44.9	$ 38.2	$ 37.6	$ 36.2	$ 30.7	$ 200.7
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Crude oil	$ 161.2	$ 161.2	$ --	$ --	$ --	$ --	$ --
Refined products	$ 1.6	$ 1.6	$ --	$ --	$ --	$ --	$ --
Natural gas	$ 5,225.1	$ 323.3	$ 515.1	$ 635.0	$ 660.6	$ 488.0	$ 2,603.1
NGLs	$ 1,923.8	$ 969.9	$ 136.4	$ 136.2	$ 136.2	$ 136.3	$ 408.8
Petrochemicals	$ 1,746.2	$ 685.6	$ 376.6	$ 247.8	$ 181.7	$ 86.8	$ 167.7
Other	$ 66.7	$ 24.2	$ 7.6	$ 7.0	$ 6.3	$ 6.2	$ 15.4
Underlying major volume commitments:							
Crude oil (in MBbls)	3,404	3,404	--	--	--	--	--
Refined products (in MBbls)	28	28	--	--	--	--	--
Natural gas (in BBtus)	981,955	56,650	93,150	115,925	120,780	93,950	501,500
NGLs (in MBbls)	56,622	23,576	4,726	4,720	4,720	4,720	14,160
Petrochemicals (in MBbls)	67,696	24,949	13,420	10,428	7,906	3,759	7,234
Service payment commitments	$ 534.4	$ 57.3	$ 51.3	$ 49.5	$ 47.0	$ 46.1	$ 283.2
Capital expenditure commitments	$ 786.7	$ 786.7	$ --	$ --	$ --	$ --	$ --

Scheduled Maturities of Long-Term Debt. We have long-term and short-term payment obligations under debt agreements. Amounts shown in the preceding table represent our scheduled future maturities of debt principal for the periods indicated. See Note 14 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year.

Our significant lease agreements involve (i) the lease of underground caverns for the storage of natural gas and NGLs, (ii) leased office space with an affiliate of EPCO, (iii) a railcar unloading terminal in Mont Belvieu, Texas and (iv) land held pursuant to right-of-way agreements. In general, our material lease agreements have original terms that range from 2 to 28 years and include renewal options that could extend the agreements for up to an additional 20 years.

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. We are generally required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred. We did not make any significant leasehold improvements during the years ended December 31, 2008, 2007 or 2006; however, we did incur $9.3 million of repair costs associated with our lease of an underground natural gas storage facility in 2006.

The operating lease commitments shown in the preceding table exclude the non-cash, related party expense associated with retained leases contributed to us by EPCO at our formation. EPCO remains liable for the actual cash lease payments associated with these agreements, which it accounts for as operating leases. At December 31, 2008, the retained leases were for approximately 100 railcars. EPCO's minimum future rental payments under these leases are $0.7 million for each of the years 2009 through 2015 and $0.3 million for 2016. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to equity accounted for as a general contribution to our partnership.

The retained lease agreements contain lessee purchase options, which are at prices that approximate fair value of the underlying leased assets. EPCO has assigned these purchase options to us. We have exercised our election under the retained leases to purchase a cogeneration unit in December 2008 for $2.3 million. Should we decide to exercise the purchase option associated with the remaining agreement, we would pay the original lessor $3.1 million in June 2016.

Lease and rental expense included in costs and expenses was $56.8 million, $61.4 million and $64.9 million during the years ended December 31, 2008, 2007 and 2006, respectively.

Purchase Obligations. We define a purchase obligation as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have classified our unconditional purchase obligations into the following categories:

§ We have long and short-term product purchase obligations for natural gas, NGLs, crude oil, refined products and certain petrochemicals with third-party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume 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 purchases made at December 31, 2008 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. At December 31, 2008, we do not have any significant product purchase commitments with fixed or minimum pricing provisions with remaining terms in excess of one year.

§ We have long and short-term commitments to pay third-party providers for services such as equipment maintenance agreements. Our contractual payment obligations vary by contract. The preceding table shows our future payment obligations under these service contracts.

§ We have short-term payment obligations relating to our capital projects and those of our unconsolidated affiliates. These commitments represent unconditional payment obligations to vendors for services rendered or products purchased. The preceding table presents our share of such commitments for the periods indicated.

Commitments under equity compensation plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us (see Note 17). This includes costs associated with unit option awards granted to these employees to purchase our common units. At December 31, 2008, there were 2,168,500 and 795,000 unit options outstanding under the EPCO 1998 Plan and EPD 2008 LTIP, respectively, for which we were responsible for reimbursing EPCO for the costs of such awards.

The weighted-average strike price of unit option awards outstanding at December 31, 2008 was $26.32 and $30.93 per common unit under the EPCO 1998 Plan and EPD 2008 LTIP, respectively. At December 31, 2008, 548,500 of these unit options were exercisable under the EPCO 1998 Plan. An additional 365,000, 480,000 and 775,000 of these unit options will be exercisable in 2009, 2010 and 2012, respectively under the EPCO 1998 Plan. The 795,000 unit options outstanding under the EPD 2008 LTIP will become exercisable in 2013. As these options are exercised, we will reimburse EPCO in the form of a special cash distribution for the difference between the strike price paid by the employee and the actual purchase price paid for the units awarded to the employee. See Note 5 for additional information regarding our accounting for equity awards.

In order to fund obligations under the TEPPCO 2006 LTIP, EPCO may purchase common units of TEPPCO at fair value either in the open market or directly from TEPPCO. When EPCO employees exercise options awarded under the TEPPCO 2006 LTIP, TEPPCO will reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the common units. TEPPCO was committed to issue 355,000 of its common units at December 31, 2008, respectively, if all outstanding options awarded under the 2006 LTIP (as of this date) were exercised. The weighted-average strike price of option awards outstanding at December 31, 2008 was $40.00 per common unit. There were no options immediately exercisable under the 2006 LTIP at December 31, 2008. See Note 5 for additional information regarding the TEPPCO 2006 LTIP.

Performance Guaranty

In December 2004, a subsidiary of ours entered into the Independence Hub Agreement (the "Agreement") with six oil and natural gas producers. The Agreement, as amended, obligated our subsidiary to construct the Independence Hub offshore platform and to process 1.0 Bcf/d of natural gas and condensate for the producers. We guaranteed to the producers the construction-related performance of our subsidiary up to an amount of $340.8 million. The performance guaranty expired during the second quarter of 2007.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of December 31, 2008, claims against us totaled approximately $15.4 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters, if any, that might result from the resolution of such disputes have not been reflected in our supplemental consolidated financial statements.

Other Commitments

We transport and store natural gas, NGLs, crude oil, refined products and petrochemicals for third parties under various processing, storage, transportation and similar agreements. These volumes are (i) accrued as product payables on our Supplemental Consolidated Balance Sheets, (ii) in transit for delivery to our customers or (iii) held at our storage facilities for redelivery to our customers. We are insured against any physical loss of such volumes due to catastrophic events. Under the terms of our natural gas, NGL and petrochemical storage agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2008, NGL, refined products and petrochemical products aggregating 40.9 million barrels were due to be redelivered to their owners along with 18.5 BBtus of natural gas and 5.2 million barrels of crude oil. See Note 2 for more information regarding accrued product payables.

Centennial Guarantees

We have certain guarantee obligations in connection with our ownership interest in Centennial. We have guaranteed one-half of Centennial's debt obligations, which obligates us to an estimated payment of $65.0 million in the event of default by Centennial. At December 31, 2008, we had a liability of $9.0 million representing the estimated fair value of our share of the Centennial debt guaranty. See Note 14 for additional information regarding Centennial's debt obligations.

In lieu of Centennial procuring insurance to satisfy third-party liabilities arising from a catastrophic event, our and Centennial's other joint venture partner has entered a limited cash call agreement. We are obligated to contribute up to a maximum of $50.0 million in proportion to our ownership interest in Centennial in the event of a catastrophic event. At December 31, 2008, we had a liability of $3.9 million representing the estimated fair value of our cash call guaranty. We insure against catastrophic events. Cash contributions to Centennial under the limited cash call agreement may be covered by our insurance depending on the nature of the catastrophic event.

Note 21. Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

Our operations are within the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil, refined products and certain petrochemicals. We also market natural gas, NGLs, crude oil and other hydrocarbon products. As such, our financial position, results of operations and cash flows may be affected by changes in the commodity prices of these hydrocarbon products, including changes in the relative price levels among these products (e.g., natural gas processing margins are influenced by the ratio of natural gas prices to crude oil prices). The prices of hydrocarbon products are subject to fluctuation in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of hydrocarbon products transported, gathered, processed or stored at our facilities. A material decrease in natural gas or crude oil production or crude oil refining, for reasons such as depressed commodity prices or a decrease in exploration and development activities, could result in a decline in the volume of natural gas, NGLs, refined products and crude oil handled by our facilities.

A reduction in demand for natural gas, crude oil, NGL and other hydrocarbon products by the petrochemical, refining or heating industries, whether because of (i) general economic conditions, (ii) reduced demand by consumers for the end products made using such products, (iii) increased competition from other products due to pricing differences, (iv) adverse weather conditions, (v) government regulations affecting energy commodity prices, production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could adversely affect our financial position, results of operations and cash flows.

Credit Risk due to Industry Concentrations

A substantial portion of our revenues are derived from companies in the domestic natural gas, NGL and petrochemical industries. This concentration could affect our overall exposure to credit risk since these customers may be affected by similar economic or other conditions. We generally do not require collateral for our accounts receivable; however, we do attempt to negotiate offset, prepayment, or automatic debit agreements with customers that are deemed to be credit risks in order to minimize our potential exposure to any defaults.

Our revenues are derived from a wide customer base. During 2008, 2007 and 2006, our largest customer was Valero Energy Corporation and its affiliates, which accounted for 11.2%, 8.9% and 9.3%, respectively, of our revenues.

On January 6, 2009, LyondellBasell Industries (“LBI”) announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. For 2008, LBI accounted for 5.9% of consolidated revenues. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. In addition, we are seeking to have LBI accept certain contracts and have filed claims pursuant to current Bankruptcy Court Orders that we expect will allow us to recover the majority of the remaining credit exposure.

Counterparty Risk with Respect to Derivative Instruments

In those situations where we are exposed to credit risk in our derivative instrument transactions, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. Generally, we do not require collateral nor do we anticipate nonperformance by our counterparties.

Weather-Related Risks

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of damage or interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

For windstorm events such as hurricanes and tropical storms, EPCO's deductible for onshore physical damage is $10.0 million per storm. For offshore assets, the windstorm deductible is $10.0 million per storm plus a one-time $15.0 million aggregate deductible per policy period. For non-windstorm events, EPCO's deductible for onshore and offshore physical damage is $5.0 million per occurrence. In meeting the deductible amounts, property damage costs are aggregated for EPCO and its affiliates, including us. Accordingly, our exposure with respect to the deductibles may be equal to or less than the stated amounts depending on whether other EPCO or affiliate assets are also affected by an event.

To qualify for business interruption coverage in connection with a windstorm event, covered assets must be out-of-service in excess of 60 days for onshore assets and 75 days for offshore assets. To qualify for business interruption coverage in connection with a non-windstorm event, covered onshore and offshore assets must be out-of-service in excess of 60 days.

The following is a discussion of the general status of our insurance claims related to recent significant storm events. To the extent we include any estimate or range of estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available.

Hurricane Ivan insurance claims. During the year ended December 31, 2008, we did not receive any reimbursements from insurance carriers related to property damage claims associated with this storm. During the year ended December 31, 2007, we received cash reimbursements from insurance carriers totaling $1.3 million, related to property damage claims. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

We have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004. During the year ended December 31, 2008, we did not receive any proceeds from these claims. During the year ended December 31, 2007, we received $0.4 million of nonrefundable cash proceeds from such claims. We are continuing our efforts to collect residual balances from this storm. To the extent we receive nonrefundable cash proceeds from business interruption insurance claims, they are recorded as a gain in our Supplemental Statements of Consolidated Operations in the period of receipt.

Hurricanes Katrina and Rita insurance claims. Hurricanes Katrina and Rita, both significant storms, affected certain of our Gulf Coast assets in August and September of 2005, respectively. With respect to these storms, we have $30.5 million of estimated property damage claims outstanding at

December 31, 2008, that we believe are probable of collection during the period 2009. We continue to pursue collection of our property damage claims related to these named storms. As of December 31, 2008, we had received all proceeds from our business interruption claims related to these storm events.

Hurricanes Gustav and Ike insurance claims. In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined $49.1 million of repair costs for property damage in connection with these two storms. We expect to file property damage insurance claims to the extent repair costs exceed deductible amounts. Due to the recent nature of these storms, we are still evaluating the total cost of repairs and the potential for business interruption claims on certain assets.

Proceeds from Business Interruption and Property Damage Claims

The following table summarizes proceeds we received during the periods indicated from business interruption and property damage insurance claims with respect to certain named storms:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Business interruption proceeds:			
Hurricane Ivan	$ --	$ 0.4	$ 17.4
Hurricane Katrina	0.5	19.0	24.5
Hurricane Rita	0.6	14.9	22.0
Other	--	1.0	--
Total proceeds	1.1	35.3	63.9
Property damage proceeds:			
Hurricane Ivan	--	1.3	24.1
Hurricane Katrina	9.4	79.6	7.5
Hurricane Rita	2.7	24.1	3.0
Other	--	0.2	--
Total proceeds	12.1	105.2	34.6
Total	$ 13.2	$ 140.5	$ 98.5

At December 31, 2008, we have $39.0 million of estimated property damage claims outstanding related to these storms that we believe are probable of collection through 2009. In February 2009, we collected $20.8 million of the amounts outstanding. To the extent we estimate the dollar value of such damages, please be aware that a change in our estimates may occur as additional information becomes available.

During 2008, we collected $0.2 million of business interruption proceeds that were not related to storm events.

Note 22. Supplemental Cash Flow Information

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

§ The timing of cash receipts from revenue transactions and cash payments for expense transactions near the end of each reporting period. For example, if significant cash receipts are posted on the last day of the current reporting period, but subsequent payments on expense invoices are made on the first day of the next reporting period, net cash flows provided by operating activities will reflect an increase in the current reporting period that will be reduced as payments are made in the next period. We employ prudent cash management practices and monitor our daily cash requirements to meet our ongoing liquidity needs.

§ If commodity or other prices increase between reporting periods, changes in accounts receivable and accounts payable and accrued expenses may appear larger than in previous periods; however, overall levels of receivables and payables may still reflect normal ranges. From a receivables standpoint, we monitor the amount of credit extended to customers.

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

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

The following table provides information regarding (i) the net effect of changes in our operating assets and liabilities; (ii) cash payments for interest and (iii) cash payments for federal and state income taxes for the periods indicated.

	For the Year Ended December 31,		
	2008	2007	2006
Decrease (increase) in:			
Accounts and notes receivable – trade	$ 1,333.9	$ (1,175.8)	$ 97.6
Accounts receivable – related party	3.6	(37.0)	5.3
Inventories	14.9	(20.4)	(110.5)
Prepaid and other current assets	(26.9)	36.6	25.0
Other assets	(11.7)	(6.7)	(34.9)
Increase (decrease) in:			
Accounts payable – trade	(9.1)	193.8	(42.8)
Accounts payable – related party	1.2	(2.2)	(30.8)
Accrued product payables	(1,722.0)	2,195.2	(779.9)
Accrued expenses	3.4	(809.3)	837.0
Accrued interest	21.8	39.9	22.4
Other current liabilities	(27.7)	44.5	53.2
Other liabilities	7.5	(23.7)	4.6
Net effect of changes in operating accounts	$ (411.1)	$ 434.9	$ 46.2
Cash payments for interest, net of $90.7, $86.5 and $66.3 capitalized in 2008, 2007 and 2006, respectively	$ 569.7	$ 429.5	$ 301.5
Cash payments for federal and state income taxes	$ 6.8	$ 5.8	$ 10.5

The following table provides supplemental cash flow information regarding business combinations we completed during the periods indicated. See Note 12 for additional information regarding our business combination transactions.

	For the Year Ended December 31,		
	2008	2007	2006
Fair value of assets acquired	$ 855.3	$ 37.1	$ 493.0
Less liabilities assumed	(301.9)	(1.2)	(19.7)
Net assets acquired	553.4	35.9	473.3
Less equity issued	--	--	(181.1)
Cash used for business combinations, net of cash received	$ 553.4	$ 35.9	$ 292.2

We incurred liabilities for construction in progress that had not been paid at December 31, 2008, 2007 and 2006 of $107.9 million, $107.0 million and $206.2 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Supplemental Statements of Consolidated Cash Flows.

Third parties may be obligated to reimburse us for all or a portion of expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. We received $28.6 million, $57.6 million and $60.5 million as contributions in aid of our construction costs during the years ended December 31, 2008, 2007 and 2006, respectively.

Note 23. Quarterly Financial Information (Unaudited)

The following table presents selected quarterly financial data for the years ended December 31, 2008 and 2007:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2008:				
Revenues	$ 8,506.4	$ 10,538.6	$ 10,499.1	$ 5,925.5
Operating income	469.7	454.6	401.0	423.1
Income before the cumulative effect of change in accounting principle	336.0	320.0	258.1	274.8
Net income	336.0	320.0	258.1	274.8
Net income attributable to Enterprise Products Partners L.P.	259.6	263.3	203.1	228.0
Earnings per unit before the cumulative effect of change in accounting principle:				
Basic	$ 0.51	$ 0.52	$ 0.38	$ 0.43
Diluted	$ 0.51	$ 0.52	$ 0.38	$ 0.43
Earnings per unit:				
Basic	$ 0.51	$ 0.52	$ 0.38	$ 0.43
Diluted	$ 0.51	$ 0.52	$ 0.38	$ 0.43
For the Year Ended December 31, 2007:				
Revenues	$ 5,340.2	$ 6,294.4	$ 6,721.7	$ 8,357.5
Operating income	342.5	284.1	284.3	284.1
Income before the cumulative effect of change in accounting principle	250.8	195.7	172.9	218.6
Net income	250.8	195.7	172.9	218.6
Net income attributable to Enterprise Products Partners L.P.	112.0	142.2	117.6	161.8
Earnings per unit before the cumulative effect of change in accounting principle:				
Basic	$ 0.19	$ 0.26	$ 0.20	$ 0.30
Diluted	$ 0.19	$ 0.26	$ 0.20	$ 0.30
Earnings per unit:				
Basic	$ 0.19	$ 0.26	$ 0.20	$ 0.30
Diluted	$ 0.19	$ 0.26	$ 0.20	$ 0.30

Note 24. Supplemental Condensed Consolidated Financial Information of EPO

EPO conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of EPO. EPO consolidates the financial statements of Duncan Energy Partners with those of its own.

Immediately after the closing of the TEPPCO Merger, Enterprise Products Partners L.P. contributed its ownership interests in TEPPCO and TEPPCO GP to EPO. The following supplemental condensed consolidated financial information for EPO has been recast to include TEPPCO and TEPPCO GP using the same basis of presentation described in Note 1 for our consolidated financial statements.

Enterprise Products Partners L.P. guarantees the debt obligations of EPO, with the exception of the Dixie revolving credit facility (terminated January 2009) and the Duncan Energy Partners' debt obligations. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation. See Note 14 for additional information regarding our consolidated debt obligations.

The reconciling items between our supplemental consolidated financial statements and those of EPO are insignificant. The following table presents supplemental condensed consolidated balance sheet data for EPO at the dates indicated:

	December 31, 2008	December 31, 2007
ASSETS		
Current assets	$ 3,114.6	$ 4,068.4
Property, plant and equipment, net	16,732.8	14,309.1
Investments in and advances to unconsolidated affiliates, net	911.9	885.6
Intangible assets, net	1,182.9	1,214.1
Goodwill	2,019.6	1,813.3
Other assets	261.1	232.0
Total	$ 24,222.9	$ 22,522.5
LIABILITIES AND EQUITY		
Current liabilities	$ 3,100.8	$ 4,958.6
Long-term debt	11,637.9	8,417.2
Other long-term liabilities	176.5	122.5
Equity	9,307.7	9,024.2
Total	$ 24,222.9	$ 22,522.5
Total EPO debt obligations guaranteed by Enterprise Products Partners L.P.	$ 8,561.8	$ 6,686.5

The following table presents supplemental condensed consolidated statements of operations data for EPO for the periods indicated:

	For the Year Ended December 31, 2008	2007	2006
Revenues	$ 35,469.6	$ 26,713.8	$ 23,612.2
Costs and expenses	33,753.4	25,526.8	22,512.3
Equity in earnings of unconsolidated affiliates	34.9	10.5	25.2
Operating income	1,751.1	1,197.5	1,125.1
Other expense	(528.6)	(343.0)	(315.0)
Income before provision for income taxes and the cumulative effect of change in accounting principle	1,222.5	854.5	810.1
Provision for income taxes	(31.0)	(15.8)	(21.9)
Income before the cumulative effect of change in accounting principle	1,191.5	838.7	788.2
Cumulative effect of change in accounting principle	--	--	1.5
Net income	1,191.5	838.7	789.7
Net income attributable to noncontrolling interest	(235.2)	(304.4)	(186.5)
Net income attributable to EPO	$ 956.3	$ 534.3	$ 603.2

Note 25. Subsequent Events

We have evaluated subsequent events through December 4, 2009, which is the date we filed this Exhibit 99.2 to Current Report on Form 8-K with the SEC.

TOPS Matters** - **April and September 2009

In April 2009, we dissociated (or exited) from TOPS (see Note 10). As a result, net income for the second quarter of 2009 reflects a non-cash charge of $68.4 million, which represented our cumulative investment in TOPS through the date of dissociation. In addition, in September 2009, we entered into a settlement agreement with certain affiliates of Oiltanking that resolved all disputes between the parties related to the business and affairs of TOPS. We recognized approximately $67.0 million of expense during the third quarter of 2009 in connection with this cash settlement. Of the $135.4 million in expense recognized during 2009, $67.7 million was allocated to noncontrolling interest.

River Terminal Charges in September 2009

In September 2009, TEPPCO determined that its Aberdeen and Boligee river terminals were impaired due to the current level of throughput volumes at the terminals and the indefinite suspension of construction projects for three new proposed river terminals. As a result, TEPPCO recorded a $17.6 million non-cash asset impairment charge during the third quarter of 2009. The assets and operations related to TEPPCO's river terminals are part of our Petrochemical & Refined Products Services business segment. These charges relating to the river terminals are allocated to former owners of TEPPCO within noncontrolling interst.

Also, TEPPCO is party to a 10-year throughput and deficiency agreement with Colonial Pipeline Company ("Colonial") whereby Colonial agreed to provide transportation services to TEPPCO's Boligee river terminal. The agreement provided for minimum annual throughput commitments. As a result of TEPPCO's decision to indefinitely suspend the three new proposed river terminal construction projects, TEPPCO accrued a liability of $28.7 million for deficiency fees that it reasonably estimated would be incurred over the term of the Colonial contract since the minimum throughput volumes were no longer expected to be achieved.

ENTERPRISE PRODUCTS PARTNERS L.P.
RECAST OF ITEM 1 FROM QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTERLY PERIOD ENDING SEPTEMBER 30, 2009

Recast of Item 1. *Financial Statements*.

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ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED SUPPLEMENTAL CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

ASSETS	September 30, 2009	December 31, 2008
Current assets:		
Cash and cash equivalents	$ 77.3	$ 61.7
Restricted cash	102.8	203.8
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $17.0 at September 30, 2009 and $17.7 at December 31, 2008	2,579.6	2,028.5
Accounts receivable – related parties	9.6	35.3
Inventories (see Note 5)	1,220.6	405.0
Derivative assets (see Note 4)	199.5	218.6
Prepaid and other current assets	168.0	149.8
Total current assets	4,357.4	3,102.7
Property, plant and equipment, net	17,297.0	16,732.8
Investments in unconsolidated affiliates	899.3	911.9
Intangible assets, net of accumulated amortization of $765.6 at September 30, 2009 and $675.1 at December 31, 2008	1,093.2	1,182.9
Goodwill	2,018.3	2,019.6
Deferred tax asset	1.1	0.4
Other assets	264.9	261.3
Total assets	$ 25,931.2	$ 24,211.6
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable – trade	$ 399.7	$ 388.9
Accounts payable – related parties	44.2	17.4
Accrued product payables	2,657.4	1,845.7
Accrued interest payable	163.1	188.3
Other accrued expenses	55.1	65.7
Derivative liabilities (see Note 4)	264.6	302.9
Other current liabilities	263.5	292.3
Total current liabilities	3,847.6	3,101.2
Long-term debt: (see Note 10)		
Senior debt obligations – principal	10,404.0	10,030.1
Junior subordinated notes – principal	1,532.7	1,532.7
Other	62.5	75.1
Total long-term debt	11,999.2	11,637.9
Deferred tax liabilities	69.6	66.1
Other long-term liabilities	151.2	110.5
Commitments and contingencies		
Equity: (see Note 11)		
Enterprise Products Partners L.P. partners' equity:		
Limited Partners:		
Common units (475,293,998 units outstanding at September 30, 2009 and 439,354,731 units outstanding at December 31, 2008)	6,670.8	6,036.9
Restricted common units (2,658,850 units outstanding at September 30, 2009 and 2,080,600 units outstanding at December 31, 2008)	34.1	26.2
General partner	136.6	123.6
Accumulated other comprehensive loss	(67.1)	(97.2)
Total Enterprise Products Partners L.P. partners' equity	6,774.4	6,089.5
Noncontrolling interest	3,089.2	3,206.4
Total equity	9,863.6	9,295.9
Total liabilities and equity	$ 25,931.2	$ 24,211.6

See Notes to Unaudited Supplemental Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED SUPPLEMENTAL CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in millions, except per unit amounts)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues:				
Third parties	$ 6,679.0	$ 10,246.1	$ 16,688.4	$ 28,812.4
Related parties	110.4	253.0	422.2	731.7
Total revenues (see Note 12)	6,789.4	10,499.1	17,110.6	29,544.1
Costs and expenses:				
Operating costs and expenses:				
Third parties	6,128.2	9,875.1	15,046.4	27,593.5
Related parties	267.6	199.2	750.5	556.7
Total operating costs and expenses	6,395.8	10,074.3	15,796.9	28,150.2
General and administrative costs:				
Third parties	26.9	12.4	56.3	29.4
Related parties	25.4	21.5	77.0	71.0
Total general and administrative costs	52.3	33.9	133.3	100.4
Total costs and expenses	6,448.1	10,108.2	15,930.2	28,250.6
Equity in income of unconsolidated affiliates	15.0	10.1	32.0	31.8
Operating income	356.3	401.0	1,212.4	1,325.3
Other income (expense):				
Interest expense	(161.0)	(137.0)	(472.0)	(396.3)
Interest income	0.3	2.5	1.9	6.2
Other, net	(0.1)	(0.7)	0.3	(1.0)
Total other expense, net	(160.8)	(135.2)	(469.8)	(391.1)
Income before provision for income taxes	195.5	265.8	742.6	934.2
Provision for income taxes	(7.7)	(7.7)	(26.8)	(20.1)
Net income	187.8	258.1	715.8	914.1
Net (income) loss attributable to noncontrolling interest	25.1	(55.0)	(91.0)	(188.1)
Net income attributable to Enterprise Products Partners L.P.	$ 212.9	$ 203.1	$ 624.8	$ 726.0
Net income allocated to:				
Limited partners	$ 171.3	$ 167.6	$ 504.6	$ 620.5
General partner	$ 41.6	$ 35.5	$ 120.2	$ 105.5
Basic and diluted earnings per unit (see Note 14)	$ 0.36	$ 0.38	$ 1.09	$ 1.41

See Notes to Unaudited Supplemental Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED SUPPLEMENTAL CONDENSED STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)
(Dollars in millions)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income	$ 187.8	$ 258.1	$ 715.8	$ 914.1
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instrument losses during period	(8.3)	(236.1)	(146.9)	(143.3)
Reclassification adjustment for losses included in net income related to commodity derivative instruments	77.8	43.9	176.3	50.5
Interest rate derivative instrument gains (losses) during period	(8.0)	(1.1)	7.1	(46.1)
Reclassification adjustment for (gains) losses included in net income related to interest rate derivative instruments	2.8	--	7.6	(2.5)
Foreign currency derivative gains (losses)	0.2	--	(10.3)	(1.3)
Total cash flow hedges	64.5	(193.3)	33.8	(142.7)
Foreign currency translation adjustment	1.1	0.4	1.7	0.5
Change in funded status of pension and postretirement plans, net of tax	--	--	--	(0.3)
Total other comprehensive income (loss)	65.6	(192.9)	35.5	(142.5)
Comprehensive income	253.4	65.2	751.3	771.6
Comprehensive (income) loss attributable to noncontrolling interest	23.3	(78.0)	(96.4)	(179.7)
Comprehensive income (loss) attributable to Enterprise Products Partners L.P.	$ 276.7	$ (12.8)	$ 654.9	$ 591.9

See Notes to Unaudited Supplemental Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED SUPPLEMENTAL CONDENSED STATEMENTS OF
CONSOLIDATED CASH FLOWS
(Dollars in millions)

	For the Nine Months Ended September 30,	
	2009	**2008**
Operating activities:		
Net income	$ 715.8	$ 914.1
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	619.9	540.7
Non-cash impairment charge	26.3	--
Equity in income of unconsolidated affiliates	(32.0)	(31.8)
Distributions received from unconsolidated affiliates	55.2	50.5
Operating lease expense paid by EPCO, Inc.	0.5	1.6
Gain from asset sales and related transactions	(0.5)	(2.0)
Loss on forfeiture of investment in Texas Offshore Port System	68.4	--
Loss on early extinguishment of debt	--	8.7
Deferred income tax expense	2.5	5.6
Changes in fair market value of derivative instruments	10.6	4.9
Effect of pension settlement recognition	(0.1)	(0.1)
Net effect of changes in operating accounts (see Note 17)	(574.9)	(241.1)
Net cash flows provided by operating activities	891.7	1,251.1
Investing activities:		
Capital expenditures	(1,100.4)	(1,844.7)
Contributions in aid of construction costs	12.8	22.5
Decrease (increase) in restricted cash	100.8	(112.2)
Cash used for business combinations	(74.5)	(408.8)
Acquisition of intangible assets	(1.4)	(5.4)
Investments in unconsolidated affiliates	(13.9)	(23.9)
Proceeds from asset sales and related activities	2.9	8.0
Other investing activities	1.5	--
Cash used in investing activities	(1,072.2)	(2,364.5)
Financing activities:		
Borrowings under debt agreements	4,963.8	10,209.3
Repayments of debt	(4,594.0)	(8,266.7)
Debt issuance costs	(5.5)	(18.5)
Cash distributions paid to partners	(860.6)	(770.9)
Cash distributions paid to noncontrolling interest (see Note 11)	(324.5)	(276.0)
Net cash proceeds from issuance of common units	878.2	57.2
Cash contributions from noncontrolling interest (see Note 11)	140.9	271.3
Acquisition of treasury units	(1.8)	(0.8)
Monetization of interest rate derivative instruments	--	(74.2)
Cash provided by financing activities	196.5	1,130.7
Effect of exchange rate changes on cash	(0.4)	(0.1)
Net change in cash and cash equivalents	16.0	17.3
Cash and cash equivalents, January 1	61.7	51.3
Cash and cash equivalents, September 30	$ 77.3	$ 68.5

See Notes to Unaudited Supplemental Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED SUPPLEMENTAL CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(See Note 11 for Unit History and Detail of Changes in Limited Partners' Equity)
(Dollars in millions)

	Enterprise Products Partners L.P.				
	Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total
Balance, December 31, 2008	$ 6,063.1	$ 123.6	$ (97.2)	$ 3,206.4	$ 9,295.9
Net income	504.6	120.2	--	91.0	715.8
Operating leases paid by EPCO, Inc.	0.5	--	--	--	0.5
Cash distributions paid to partners	(735.2)	(124.9)	--	--	(860.1)
Unit option reimbursements to EPCO, Inc.	(0.5)	--	--	--	(0.5)
Cash distributions paid to noncontrolling interest (see Note 11)	--	--	--	(324.5)	(324.5)
Net cash proceeds from issuance of common units	860.2	17.5	--	--	877.7
Cash proceeds from exercise of unit options	0.5	--	--	--	0.5
Cash contributions from noncontrolling interest (see Note 11)	--	--	--	140.9	140.9
Deconsolidation of Texas Offshore Port System	--	--	--	(33.4)	(33.4)
Amortization of equity awards	13.5	0.2	--	3.1	16.8
Acquisition of treasury units	(1.8)	--	--	--	(1.8)
Foreign currency translation adjustment	--	--	1.7	--	1.7
Cash flow hedges	--	--	28.4	5.4	33.8
Other	--	--	--	0.3	0.3
Balance, September 30, 2009	$ 6,704.9	$ 136.6	$ (67.1)	$ 3,089.2	$ 9,863.6

	Enterprise Products Partners L.P.				
	Limited Partners	General Partner	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2007	$ 5,992.9	$ 122.3	$ 19.1	2,882.2	$ 9,016.5
Net income	620.5	105.5	--	188.1	914.1
Operating leases paid by EPCO, Inc.	1.6	--	--	--	1.6
Cash distributions paid to partners	(663.9)	(106.4)	--	--	(770.3)
Unit option reimbursements to EPCO, Inc.	(0.6)	--	--	--	(0.6)
Cash distributions paid to noncontrolling interest (see Note 11)	--	--	--	(276.0)	(276.0)
Net cash proceeds from issuance of common units	55.4	1.1	--	--	56.5
Issuance of units by TEPPCO in connection with Cenac acquisition	--	--	--	186.6	186.6
Cash proceeds from exercise of unit options	0.7	--	--	--	0.7
Cash contributions from noncontrolling interest (see Note 11)	--	--	--	271.3	271.3
Amortization of equity awards	8.7	0.1	--	1.1	9.9
Interest acquired from noncontrolling interest	--	--	--	(7.6)	(7.6)
Acquisition of treasury units	(0.8)	--	--	--	(0.8)
Foreign currency translation adjustment	--	--	0.5	--	0.5
Change in funded status of pension and postretirement plans	--	--	(0.3)	--	(0.3)
Cash flow hedges	--	--	(134.4)	(8.3)	(142.7)
Other	--	--	--	0.5	0.5
Balance, September 30, 2008	$ 6,014.5	$ 122.6	$ (115.1)	$ 3,237.9	$ 9,259.9

See Notes to Unaudited Supplemental Condensed Consolidated Financial Statements.

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

Note 1. Partnership Organization and Basis of Presentation

Partnership Organization

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our" or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries, which now includes TEPPCO Partners, L.P. and its general partner.

We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO, Inc. ("EPCO"). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating LLC ("EPO"). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as "EPGP"). EPGP is owned 100% by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded limited partnership, the units of which are listed on the NYSE under the ticker symbol "EPE." The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), a wholly owned subsidiary of Dan Duncan LLC, all of the membership interests of which are owned by Dan L. Duncan. We, EPGP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates and under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries. On October 26, 2009, we completed the mergers with TEPPCO and TEPPCO GP (such related mergers referred to herein individually and together as the "TEPPCO Merger"). See Note 19 for additional information regarding the TEPPCO Merger.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries. References to "LE GP" mean LE GP, LLC, which is the general partner of Energy Transfer Equity. Enterprise GP Holdings owns a noncontrolling interest in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to "Employee Partnerships" mean EPE Unit L.P., EPE Unit II, L.P., EPE Unit III, L.P., Enterprise Unit L.P., EPCO Unit L.P., TEPPCO Unit L.P., and TEPPCO Unit II L.P., collectively, all of which are privately held affiliates of EPCO, Inc.

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners L.P. ("Duncan Energy Partners") with those of our own and reflect its operations in our business segments. We control Duncan Energy Partners through our ownership of its general partner, DEP Holdings, LLC ("DEP GP"). Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of noncontrolling interest in our supplemental consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, neither Enterprise Products Partners L.P. nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

Basis of Presentation

TEPPCO Merger. Since Enterprise Products Partners, TEPPCO and TEPPCO GP are under common control of Mr. Duncan, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. The inclusion of TEPPCO and TEPPCO GP in our supplemental consolidated financial statements was effective January 1, 2005 because an affiliate of EPCO under common control with Enterprise Products Partners originally acquired ownership interests in TEPPCO GP in February 2005.

Our supplemental consolidated financial statements prior to the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third party and related party ownership interests in TEPPCO and TEPPCO GP prior to the merger have been reflected as "Former owners of TEPPCO" a component of noncontrolling interest.

Our supplemental financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). The financial statements of TEPPCO and TEPPCO GP were prepared from the separate accounting records maintained by TEPPCO and TEPPCO GP. All intercompany balances and transactions were eliminated in consolidation.

We revised our business segments and related disclosures to reflect the TEPPCO Merger. Our reorganized business segments reflect the manner in which these businesses are managed and reviewed by the chief executive officer of our general partner. Under our new business segment structure, we have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services.

As previously noted, the TEPPCO Merger was accounted for as a reorganization of entities under common control. The following information is provided to reconcile total revenues and total gross operating margin as currently presented for the three and nine months ended September 30, 2009 and 2008, with those we previously presented. There was no change in net income attributable to Enterprise Products Partners L.P. for such periods since net income attributable to TEPPCO and TEPPCO GP was allocated to noncontrolling interests. Additionally, there was no change in our reported earnings per unit for such periods. See Note 12 for information regarding total segment gross operating margin, which is a non-generally accepted accounting principle ("non-GAAP") financial measure of segment performance.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Total revenues, as previously reported	$ 4,596.1	$ 6,297.9	$ 11,527.1	$ 18,322.1
Revenues from TEPPCO	2,205.3	4,205.7	5,576.1	11,194.7
Revenues from Jonah Gas Gathering Company ("Jonah") (1)	60.2	58.7	180.8	177.0
Eliminations (2)	(72.2)	(63.2)	(173.4)	(149.7)
Total revenues, as currently reported	$ 6,789.4	$ 10,499.1	$ 17,110.6	$ 29,544.1
Total segment gross operating margin, as previously reported	$ 560.9	$ 478.9	$ 1,618.8	$ 1,535.5
Gross operating margin from TEPPCO	62.5	122.9	309.9	379.7
Gross operating margin from Jonah	46.6	40.7	137.8	121.9
Eliminations (3)	(31.3)	(26.9)	(91.6)	(79.5)
Total segment gross operating margin, as currently reported	$ 638.7	$ 615.6	$ 1,974.9	$ 1,957.6

(1) Prior to the TEPPCO Merger, we and TEPPCO were joint venture partners in Jonah. As a result of the TEPPCO Merger, Jonah became a consolidated subsidiary.
(2) Represents the eliminations of revenues between us, TEPPCO and Jonah.
(3) Represents equity earnings from Jonah recorded by us and TEPPCO prior to the merger.

Noncontrolling Interests. Effective January 1, 2009, we adopted new accounting guidance that has been codified under Accounting Standards Codification ("ASC") 810, Consolidation, which established accounting and reporting standards for noncontrolling interests that were previously identified as minority interest in our financial statements. The new guidance requires, among other things, that (i) noncontrolling interests be presented as a component of equity on our consolidated balance sheet (i.e., elimination of the "mezzanine" presentation previously used for minority interest); (ii) elimination of minority interest amounts as a deduction in deriving net income or loss and, as a result, that net income or loss be allocated between controlling and noncontrolling interests; and (iii) comprehensive income or loss be allocated between controlling and noncontrolling interest. Earnings per unit amounts are not affected by these changes. See Note 2 for additional information regarding the establishment of the ASC by the Financial Accounting Standards Board ("FASB"). See Note 11 for additional information regarding noncontrolling interest.

The new presentation and disclosure requirements pertaining to noncontrolling interests have been applied retroactively to the supplemental consolidated financial statements and notes included in this Exhibit 99.3. As a result, net income reported for the three and nine months ended September 30, 2008 in these supplemental financial statements is higher than that disclosed previously; however, the allocation of such net income results in our unitholders, general partner and noncontrolling interests (i.e., the former minority interest) receiving the same amounts as they did previously.

General. Our results of operations for the three and nine months ended September 30, 2009 are not necessarily indicative of results expected for the full year.

Essentially all of our assets, liabilities, revenues and expenses are recorded at EPO's level in our supplemental consolidated financial statements. Enterprise Products Partners L.P. acts as guarantor of certain of EPO's debt obligations. See Note 18 for supplemental condensed consolidated financial information of EPO.

In our opinion, the accompanying Unaudited Supplemental Condensed Consolidated Financial Statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these supplemental financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual supplemental financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). These Unaudited Supplemental Condensed Consolidated Financial Statements and Notes thereto should be read in conjunction with the Audited Supplemental Consolidated Financial Statements and Notes thereto included in this Current Report on Form 8-K under Exhibit 99.2.

Note 2. General Accounting Matters

Estimates

Preparing our supplemental financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (e.g. assets, liabilities, revenues and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

Fair Value Information

Cash and cash equivalents and restricted cash, accounts receivable, accounts payable and accrued expenses, and other current liabilities are carried at amounts which reasonably approximate their fair values due to their short-term nature. The estimated fair values of our fixed rate debt are based on quoted market prices for such debt or debt of similar terms and maturities. The carrying amounts of our variable rate debt obligations reasonably approximate their fair values due to their variable interest rates. See Note 4 for fair value information associated with our derivative instruments. The following table presents the estimated fair values of our financial instruments at the dates indicated:

	September 30, 2009		December 31, 2008	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents and restricted cash	$ 180.1	$ 180.1	$ 265.5	$ 265.5
Accounts receivable	2,589.2	2,589.2	2,063.8	2,063.8
Financial liabilities:				
Accounts payable and accrued expenses	3,319.5	3,319.5	2,506.0	2,506.0
Other current liabilities	263.5	263.5	292.3	292.3
Fixed-rate debt (principal amount)	9,986.7	10,450.6	9,704.3	8,192.2
Variable-rate debt	1,950.0	1,950.0	1,858.5	1,858.5

Recent Accounting Developments

The following information summarizes recently issued accounting guidance that will or may affect our future financial statements.

Generally Accepted Accounting Principles. In June 2009, the FASB published ASC 105, Generally Accepted Accounting Principles, as the source of authoritative GAAP for U.S. companies. The ASC reorganized GAAP into a topical format and significantly changes the way users research accounting issues. For SEC registrants, the rules and interpretive releases of the SEC under federal securities laws are also sources of authoritative GAAP. References to specific GAAP in our supplemental consolidated financial statements now refer exclusively to the ASC. We adopted the new codification on September 30, 2009.

Fair Value Measurements. In April 2009, the FASB issued ASC 820, Fair Value Measurements and Disclosures, to clarify fair value accounting rules. This new accounting guidance establishes a process to determine whether a market is active and a transaction is consummated under distress. Companies should review several factors and use professional judgment to ascertain if a formerly active market has become inactive. When estimating fair value, companies are required to place more weight on observable transactions in orderly markets. Our adoption of this new guidance on June 30, 2009 did not have any impact on our supplemental consolidated financial statements or related disclosures.

In August 2009, the FASB issued Accounting Standards Update 2009-05, Measuring Liabilities at Fair Value, to clarify how an entity should estimate the fair value of liabilities. If a quoted price in an active market for an identical liability is not available, a company must measure the fair value of the liability using one of several valuation techniques (e.g., quoted prices for similar liabilities or present value of cash flows). Our adoption of this new guidance on October 1, 2009 did not have any impact on our supplemental consolidated financial statements or related disclosures.

Financial Instruments. In April 2009, the FASB issued ASC 825, Financial Instruments, which requires companies to provide in each interim report both qualitative and quantitative information regarding fair value estimates for financial instruments not recorded on the balance sheet at fair value. Previously, this was only an annual requirement. Apart from adding the required fair value disclosures within this Note 2, our adoption of this new guidance on June 30, 2009 did not have a material impact on our supplemental consolidated financial statements or related disclosures.

Subsequent Events. In May 2009, the FASB issued ASC 855, Subsequent Events, which governs the accounting for, and disclosure of, events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The date through which an entity has evaluated subsequent events is now a required disclosure. Our adoption of this guidance on June 30, 2009 did not have any impact on our supplemental consolidated financial statements.

Consolidation of Variable Interest Entities. In June 2009, the FASB amended consolidation guidance for variable interest entities ("VIEs") under ASC 810. VIEs are entities whose equity investors do not have sufficient equity capital at risk such that the entity cannot finance its own activities. When a business has a "controlling financial interest" in a VIE, the assets, liabilities and profit or loss of that entity must be consolidated. A business must also consolidate a VIE when that business has a "variable interest" that (i) provides the business with the power to direct the activities that most significantly impact the economic performance of the VIE and (ii) funds most of the entity's expected losses and/or receives most of the entity's anticipated residual returns. The amended guidance:

§ eliminates the scope exception for qualifying special-purpose entities;

§ amends certain guidance for determining whether an entity is a VIE;

§ expands the list of events that trigger reconsideration of whether an entity is a VIE;

§ requires a qualitative rather than a quantitative analysis to determine the primary beneficiary of a VIE;

§ requires continuous assessments of whether a company is the primary beneficiary of a VIE; and

§ requires enhanced disclosures about a company's involvement with a VIE.

The amended guidance is effective for us on January 1, 2010. At September 30, 2009, we did not have any VIEs based on prior guidance. We are in the process of evaluating the amended guidance; however, our adoption and implementation of this guidance is not expected to have an impact on our consolidated financial statements.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and related physical natural gas and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At September 30, 2009 and December 31, 2008, our restricted cash amounts were $102.8 million and $203.8 million, respectively. See Note 4 for additional information regarding derivative instruments and hedging activities.

Subsequent Events

We have evaluated subsequent events through November 9, 2009, which is the original filing date of our Quarterly Report on Form 10-Q for the nine months ended September 30, 2009.

Note 3. Accounting for Equity Awards

Certain key employees of EPCO participate in long-term incentive compensation plans managed by EPCO. The compensation expense we record related to equity awards is based on an allocation of the total cost of such incentive plans to EPCO. We record our pro rata share of such costs based on the percentage of time each employee spends on our consolidated business activities. Such awards were not material to our consolidated financial position, results of operations or cash flows for the periods presented. The amount of equity-based compensation allocable to our businesses was $7.0 million and $5.0 million for the three months ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009 and 2008, the amount of equity-based compensation allocable to our businesses was $17.4 million and $12.5 million, respectively.

EPCO 1998 Long-Term Incentive Plan

The EPCO 1998 Long-Term Incentive Plan ("EPCO 1998 Plan") provides for the issuance of up to 7,000,000 of our common units. After giving effect to the issuance or forfeiture of option awards and restricted unit awards through September 30, 2009, a total of 428,847 additional common units could be issued under the EPCO 1998 Plan.

Unit Option Awards. The following table presents option activity under the EPCO 1998 Plan for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2008	2,168,500	$ 26.32		
Granted (2)	30,000	$ 20.08		
Exercised	(56,000)	$ 15.66		
Forfeited	(365,000)	$ 26.38		
Outstanding at September 30, 2009	1,777,500	$ 26.54	4.6	$ 3.0
Options exercisable at				
September 30, 2009	652,500	$ 23.71	4.7	$ 3.0

(1) Aggregate intrinsic value reflects fully vested unit options at September 30, 2009.
(2) Aggregate grant date fair value of these unit options issued during 2009 was $0.2 million based on the following assumptions: (i) a grant date market price of our common units of $20.08 per unit; (ii) expected life of options of 5.0 years; (iii) risk-free interest rate of 1.81%; (iv) expected distribution yield on our common units of 10%; and (v) expected unit price volatility on our common units of 72.76%.

The total intrinsic value of option awards exercised during the three months ended September 30, 2009 and 2008 was $0.3 million and $0.1 million, respectively. For each of the nine months ended September 30, 2009 and 2008, the total intrinsic value of option awards exercised was $0.6 million. At September 30, 2009, the estimated total unrecognized compensation cost related to nonvested unit option awards granted under the EPCO 1998 Plan was $1.1 million. We will recognize our share of these costs in accordance with the EPCO administrative services agreement (the "ASA") (see Note 13) over a weighted-average period of 1.8 years.

During the nine months ended September 30, 2009 and 2008, we received cash of $0.5 million and $0.7 million, respectively, from the exercise of option awards granted under the EPCO 1998 Plan. Conversely, our option-related reimbursements to EPCO during each of these periods were $0.5 million and $0.6 million, respectively.

Restricted Unit Awards. The following table summarizes information regarding our restricted unit awards under the EPCO 1998 Plan for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted units at December 31, 2008	2,080,600	
Granted (2)	1,016,950	$ 20.65
Vested	(244,300)	$ 26.66
Forfeited	(194,400)	$ 28.92
Restricted units at September 30, 2009	2,658,850	

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued. The weighted-average grant date fair value per unit for forfeited and vested awards is determined before an allowance for forfeitures.
(2) Net of forfeitures, aggregate grant date fair value of restricted unit awards issued during 2009 was $21.0 million based on grant date market prices of our common units ranging from $20.08 to $27.66 per unit. Estimated forfeiture rates ranged between 4.6% and 17%.

The total fair value of restricted unit awards that vested during the three and nine months ended September 30, 2009 was $6.2 million and $6.5 million, respectively. At September 30, 2009, the estimated total unrecognized compensation cost related to nonvested restricted unit awards granted under the EPCO 1998 Plan was $39.6 million. We expect to recognize our share of this cost over a weighted-average period of 2.5 years in accordance with the ASA.

Phantom Unit Awards and Distribution Equivalent Rights. No phantom unit awards or distribution equivalent rights have been issued as of September 30, 2009 under the EPCO 1998 Plan.

Enterprise Products 2008 Long-Term Incentive Plan

The Enterprise Products 2008 Long-Term Incentive Plan ("EPD 2008 LTIP") provides for the issuance of up to 10,000,000 of our common units. After giving effect to the issuance or forfeiture of option awards through September 30, 2009, a total of 7,865,000 additional common units could be issued under the EPD 2008 LTIP.

Unit Option Awards. The following table presents unit option activity under the EPD 2008 LTIP for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)
Outstanding at December 31, 2008	795,000	$ 30.93	
Granted (1)	1,430,000	$ 23.53	
Forfeited	(90,000)	$ 30.93	
Outstanding at September 30, 2009 (2)	2,135,000	$ 25.97	4.9

(1) Net of forfeitures, aggregate grant date fair value of these unit options issued during 2009 was $6.5 million based on the following assumptions: (i) a weighted-average grant date market price of our common units of $23.53 per unit; (ii) weighted-average expected life of options of 4.9 years; (iii) weighted-average risk-free interest rate of 2.14%; (iv) expected weighted-average distribution yield on our common units of 9.37%; (v) expected weighted-average unit price volatility on our common units of 57.11%. An estimated forfeiture rate of 17% was applied to awards granted during 2009.
(2) No unit options were exercisable as of September 30, 2009.

At September 30, 2009, the estimated total unrecognized compensation cost related to nonvested unit option awards granted under the EPD 2008 LTIP was $6.6 million. We expect to recognize our share of this cost over a weighted-average period of 3.4 years in accordance with the ASA.

Phantom Unit Awards. There were a total of 10,600 phantom units outstanding at September 30, 2009 under the EPD 2008 LTIP. These awards cliff vest in 2011 and 2012. At September 30, 2009 and December 31, 2008, we had accrued an immaterial liability for compensation related to these phantom unit awards.

DEP GP Unit Appreciation Rights

At September 30, 2009 and December 31, 2008, we had a total of 90,000 outstanding unit appreciation rights ("UARs") granted to non-employee directors of DEP GP that cliff vest in 2012. If a director resigns prior to vesting, his UAR awards are forfeited. At September 30, 2009 and December 31, 2008, we had accrued an immaterial liability for compensation related to these UARs.

TEPPCO 1999 Phantom Unit Retention Plan

There were a total of 2,800 phantom units outstanding under the TEPPCO 1999 Phantom Unit Retention Plan ("TEPPCO 1999 Plan") at September 30, 2009, which cliff vest in January 2010. During the first quarter of 2009, 2,800 phantom units that were outstanding at December 31, 2008 under the TEPPCO 1999 Plan were forfeited. Additionally, in April 2009, 13,000 phantom units vested, resulting in a cash payment of $0.3 million. At September 30, 2009 and December 31, 2008, TEPPCO had accrued liability balances of $0.1 million and $0.4 million, respectively, for compensation related to the TEPPCO 1999 Plan.

Effective upon the consummation of the TEPPCO Merger (see Note 19), we assumed the unvested phantom units outstanding on October 26, 2009 under the TEPPCO 1999 Plan and, based on the TEPPCO Merger exchange ratio, converted them into an equivalent number of our phantom units. The vesting terms and other provisions remain unchanged.

TEPPCO 2000 Long-Term Incentive Plan

On December 31, 2008, 11,300 phantom units vested and $0.2 million was paid out to participants in the first quarter of 2009. There are no remaining phantom units outstanding under the TEPPCO 2000 Long-Term Incentive Plan.

TEPPCO 2005 Phantom Unit Plan

On December 31, 2008, 36,600 phantom units vested and $0.6 million was paid out to participants in the first quarter of 2009. There are no remaining phantom units outstanding under the TEPPCO 2005 Phantom Unit Plan.

EPCO 2006 TPP Long-Term Incentive Plan

The EPCO 2006 TPP Long-Term Incentive Plan ("TEPPCO 2006 LTIP") provides for the issuance of up to 5,000,000 of TEPPCO's units. After giving effect to the issuance or forfeiture of unit options and restricted units through September 30, 2009, a total of 4,268,546 additional units of TEPPCO could be issued under the TEPPCO 2006 LTIP. However, after giving effect to the TEPPCO Merger, no additional units will be issued under the TEPPCO 2006 LTIP other than our common units pursuant to awards we assumed under this plan in accordance with the TEPPCO Merger agreements.

Effective upon the consummation of the TEPPCO Merger (see Note 19), we assumed the unvested awards outstanding on October 26, 2009 under the TEPPCO 2006 LTIP and, based on the TEPPCO Merger exchange ratio, converted them into an equivalent number of our awards except for UARs and phantom unit awards held by non-employee directors of TEPPCO GP which were settled in cash. The vesting terms and other provisions remain unchanged.

TEPPCO Unit Options. The following table presents unit option activity under the TEPPCO 2006 LTIP for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)
Outstanding at December 31, 2008	355,000	$ 40.00	
Granted (1)	329,000	$ 24.84	
Forfeited	(205,000)	$ 33.45	
Outstanding at September 30, 2009 (2)	479,000	$ 32.39	4.5

(1) Net of forfeitures, aggregate grant date fair value of these awards granted during 2009 was $1.4 million based on the following assumptions: (i) weighted-average expected life of the options of 4.8 years; (ii) weighted-average risk-free interest rate of 2.1%; (iii) weighted-average expected distribution yield on TEPPCO's units of 11.3% and (iv) weighted-average expected unit price volatility on TEPPCO's units of 59.3%. An estimated forfeiture rate of 17% was applied to awards granted during 2009.
(2) No unit options were exercisable as of September 30, 2009.

At September 30, 2009, the estimated total unrecognized compensation cost related to nonvested option awards granted under the TEPPCO 2006 LTIP was $1.2 million. TEPPCO expects to recognize its share of this cost over a weighted-average period of 3.2 years in accordance with the ASA.

TEPPCO Restricted Units. The following table summarizes information regarding TEPPCO's restricted unit awards under the TEPPCO 2006 LTIP for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted units at December 31, 2008	157,300	
Granted (2)	141,950	$ 23.98
Vested	(5,000)	$ 34.63
Forfeited	(45,850)	$ 35.25
Restricted units at September 30, 2009	248,400	

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued. The weighted-average grant date fair value per unit for forfeited awards is determined before an allowance for forfeitures.
(2) Net of forfeitures, aggregate grant date fair value of restricted unit awards issued during 2009 was $3.4 million based on grant date market prices of TEPPCO's units ranging from $28.81 to $34.40 per unit. An estimated forfeiture rate of 17% was applied to awards granted during 2009.

The total fair value of TEPPCO's restricted unit awards that vested during the nine months ended September 30, 2009 was $0.1 million. At September 30, 2009, the estimated total unrecognized compensation cost related to restricted unit awards granted under the TEPPCO 2006 LTIP was $5.3 million. TEPPCO expects to recognize its share of this cost over a weighted-average period of 2.9 years in accordance with the ASA.

TEPPCO UARs and Phantom Units. At September 30, 2009, there were a total of 95,654 UARs outstanding that had been granted under the TEPPCO 2006 LTIP to non-employee directors of TEPPCO GP and 265,160 UARs outstanding that were granted to certain employees of EPCO who work on behalf of TEPPCO. These UAR awards to employees are subject to five year cliff vesting. If the employee resigns prior to vesting, their UAR awards are forfeited. The UAR awards held by non-employee directors of TEPPGO GP were settled in cash on the effective date of the TEPPCO Merger.

As of September 30, 2009 and December 31, 2008, there were a total of 1,647 phantom unit awards outstanding that had been granted under the TEPPCO 2006 LTIP to non-employee directors of TEPPCO GP. The phantom unit awards were settled in cash on the effective date of the TEPPCO Merger.

Employee Partnerships

As of September 30, 2009, the estimated total unrecognized compensation cost related to the seven Employee Partnerships was $40.6 million. We will recognize our share of these costs in accordance with the ASA over a weighted-average period of 4.2 years.

On October 26, 2009, TEPPCO Unit was dissolved and its assets distributed to its partners. Also on October 26, 2009, the 123,185 TEPPCO units held by TEPPCO Unit II were exchanged for 152,749 of our common units in connection with the TEPPCO Merger. See Note 19 for additional information regarding the TEPPCO Merger.

Note 4. Derivative Instruments, Hedging Activities and Fair Value Measurements

In the course of our normal business operations, we are exposed to certain risks, including changes in interest rates, commodity prices and, to a limited extent, foreign exchange rates. In order to manage risks associated with certain identifiable and anticipated transactions, we use derivative instruments. Derivatives are financial instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Typical derivative instruments include futures, forward contracts, swaps and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We are required to recognize derivative instruments at fair value as either assets or liabilities on the balance sheet. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of the derivative instruments will be reported in different ways depending on the nature and effectiveness of the hedging activities to which they are related. After meeting specified conditions, a qualified derivative may be specifically designated as a total or partial hedge of:

§ Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment - In a fair value hedge, all gains and losses (of both the derivative instrument and the hedged item) are recognized in income during the period of change.

§ Variable cash flows of a forecasted transaction - In a cash flow hedge, the effective portion of the hedge is reported in other comprehensive income (“OCI”) and is reclassified into earnings when the forecasted transaction affects earnings.

§ Foreign currency exposure, such as through an unrecognized firm commitment.

An effective hedge is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of changes in the fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge is the amount by which the derivative instrument exactly offsets the change in fair value of the hedged item during the reporting period. Conversely, ineffectiveness represents the change in the fair value of the derivative instrument that does not exactly offset the change in the fair value of the hedged item. Any ineffectiveness associated with a hedge is recognized in earnings immediately. Ineffectiveness can be caused by, among other things, changes in the timing of forecasted transactions or a mismatch of terms between the derivative instrument and the hedged item.

Interest Rate Derivative Instruments

We utilize interest rate swaps, treasury locks and similar derivative instruments to manage our exposure to changes in the interest rates of certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following table summarizes our interest rate derivative instruments outstanding at September 30, 2009, all of which were designated as hedging instruments under ASC 815-20, Hedging - General:

Hedged Transaction	Number and Type of Derivative Employed	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Enterprise Products Partners:					
Senior Notes C	1 fixed-to-floating swap	$ 100.0	1/04 to 2/13	6.4% to 2.8%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	$ 300.0	10/04 to 10/14	5.6% to 2.6%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	$ 400.0	6/09 to 8/12	4.6% to 2.7%	Fair value hedge
Duncan Energy Partners:					
Variable-interest rate borrowings	3 floating-to-fixed swaps	$ 175.0	9/07 to 9/10	0.3% to 4.6%	Cash flow hedge

The changes in fair value of the fair value interest rate swaps and the related hedged items were recorded on the balance sheet with the offset recorded as interest expense. This resulted in an increase of interest expense of $2.5 million and $3.1 million, respectively, for the three and nine months ended September 30, 2009.

At times, we may use treasury lock derivative instruments to hedge the underlying U.S. treasury rates related to forecasted issuances of debt. As cash flow hedges, gains or losses on these instruments are recorded in OCI and amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. In March 2008, we terminated treasury locks having a combined notional amount of $950.0 million. On April 1, 2008, we terminated treasury locks having a notional amount of $250.0 million. We recognized an aggregate loss of $43.9 million in OCI during the first quarter of 2008 related to these terminations. There were no losses recognized during the second quarter of 2008 in connection with such terminations.

During the nine months ended September 30, 2009, we entered into three forward starting interest rate swaps to hedge the underlying benchmark interest payments related to the forecasted issuances of debt.

Hedged Transaction	Number and Type of Derivative Employed	Notional Amount	Period of Hedge	Average Rate Locked	Accounting Treatment
Future debt offering	1 forward starting swap	$ 50.0	6/10 to 6/20	3.3%	Cash flow hedge
Future debt offering	2 forward starting swaps	$ 200.0	2/11 to 2/21	3.6%	Cash flow hedge

The fair market value of the forward starting swaps was $8.1 million at September 30, 2009. We entered into one additional forward starting swap for $50.0 million in October 2009 to hedge the February 2011 to February 2021 future debt offering.

For information regarding consolidated fair value amounts and gains and losses on interest rate derivative instruments and related hedged items, see "Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items" within this Note 4.

Commodity Derivative Instruments

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, demand, general market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risk associated with such products, we enter into commodity derivative instruments such as forwards, basis swaps and futures contracts. The following table summarizes our commodity derivative instruments outstanding at September 30, 2009:

	Volume (1)		**Accounting**
Derivative Purpose	**Current**	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Enterprise Products Partners:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (“PTR”) (3)	16.6 Bcf	n/a	Cash flow hedge
Forecasted NGL sales	1.0 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs	0.1 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs	n/a	0.1 MMBbls	Cash flow hedge
Forecasted sales of octane enhancement products	1.0 MMBbls	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	7.2 Bcf	n/a	Fair value hedge
Forecasted purchases of natural gas	n/a	3.0 Bcf	Cash flow hedge
Forecasted sales of natural gas	4.2 Bcf	0.9 Bcf	Cash flow hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	2.7 MMBbls	0.1 MMBbls	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	7.0 MMBbls	0.4 MMBbls	Cash flow hedge
Derivatives not designated as hedging instruments:			
Enterprise Products Partners:			
Natural gas risk management activities (4) (5)	313.3 Bcf	34.4 Bcf	Mark-to-market
Crude oil risk management activities (6)	4.7 MMBbls	n/a	Mark-to-market
Duncan Energy Partners:			
Natural gas risk management activities (5)	1.7 Bcf	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives included in the long-term column is December 2012.
(3) PTR represents the British thermal unit equivalent of the NGLs extracted from natural gas by a processing plant, and includes the natural gas used as plant fuel to extract those liquids, plant flare and other shortages. See the discussion below for the primary objective of this strategy.
(4) Volume includes approximately 61.8 billion cubic feet (“Bcf”) of physical derivative instruments that are predominantly priced as an index plus a premium or minus a discount.
(5) Reflects the use of derivative instruments to manage risks associated with natural gas transportation, processing and storage assets.
(6) Reflects the use of derivative instruments to manage risks associated with our portfolio of crude oil storage assets.

The table above does not include additional hedges of forecasted NGL sales executed under contracts that have been designated as normal purchase and sale agreements. At September 30, 2009, the volume hedged under these contracts was 4.6 million barrels (“MMBbls”).

Certain of our derivative instruments do not meet hedge accounting requirements; therefore, they are accounted for as economic hedges using mark-to-market accounting.

Our three predominant hedging strategies are hedging natural gas processing margins, hedging anticipated future sales of NGLs associated with volumes held in inventory and hedging the fair value of natural gas in inventory.

The objective of our natural gas processing strategy is to hedge a level of gross margins associated with the NGL forward sales contracts (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) by locking in the cost of natural gas used for PTR through the use of commodity derivative instruments. This program consists of:

- the forward sale of a portion of our expected equity NGL production at fixed prices through December 2009, and

- the purchase, using commodity derivative instruments, of the amount of natural gas expected to be consumed as PTR in the production of such equity NGL production.

At September 30, 2009, this program had hedged future estimated gross margins (before plant operating expenses) of $131.0 million on 5.0 MMBbls of forecasted NGL forward sales transactions extending through December 2009.

The objective of our NGL sales hedging program is to hedge future sales of NGL inventory by locking in the sales price through the use of commodity derivative instruments.

The objective of our natural gas inventory hedging program is to hedge the fair value of natural gas currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

For information regarding consolidated fair value amounts and gains and losses on commodity derivative instruments and related hedged items, see “Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items” within this Note 4.

Foreign Currency Derivative Instruments

We are exposed to foreign currency exchange risk in connection with our NGL and natural gas marketing activities in Canada. As a result, we could be adversely affected by fluctuations in currency rates between the U.S. dollar and Canadian dollar. In order to manage this risk, we may enter into foreign exchange purchase contracts to lock in the exchange rate. Prior to 2009, these derivative instruments were accounted for using mark-to-market accounting. Beginning with the first quarter of 2009, the long-term transactions (more than two months) are accounted for as cash flow hedges. Shorter term transactions are accounted for using mark-to-market accounting.

In addition, we were exposed to foreign currency exchange risk in connection with a term loan denominated in Japanese yen (see Note 10). We entered into this loan agreement in November 2008 and the loan matured in March 2009. The derivative instrument used to hedge this risk was accounted for as a cash flow hedge and settled upon repayment of the loan.

At September 30, 2009, we had foreign currency derivative instruments outstanding with a notional amount of $5.5 million Canadian. The fair market value of these instruments was an asset of $0.3 million at September 30, 2009.

For information regarding consolidated fair value amounts and gains and losses on foreign currency derivative instruments and related hedged items, see “Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items” within this Note 4.

Credit-Risk Related Contingent Features in Derivative Instruments

A limited number of our commodity derivative instruments include provisions related to credit ratings and/or adequate assurance clauses. A credit rating provision provides for a counterparty to demand immediate full or partial payment to cover a net liability position upon the loss of a stipulated credit rating. An adequate assurance clause provides for a counterparty to demand immediate full or partial payment to cover a net liability position should reasonable grounds for insecurity arise with respect to contractual performance by either party. At September 30, 2009, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was $5.7 million, the total of which was subject to a credit rating contingent feature. If our credit ratings were downgraded to Ba2/BB, approximately $5.0 million would be payable as a margin deposit to the counterparties, and if our credit ratings were downgraded to Ba3/BB- or below, approximately $5.7 million would be payable as a margin deposit to the counterparties. Currently, no margin is required to be deposited. The potential for derivatives with contingent features to enter a net liability position may change in the future as positions and prices fluctuate.

Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items

The following table provides a balance sheet overview of our derivative assets and liabilities at the dates indicated:

	Asset Derivatives				Liability Derivatives			
	September 30, 2009		December 31, 2008		September 30, 2009		December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:								
Interest rate derivatives	Derivative assets	$ 23.2	Derivative assets	$ 7.8	Derivative liabilities	$ 6.0	Derivative liabilities	$ 5.9
Interest rate derivatives	Other assets	33.4	Other assets	38.9	Other liabilities	2.0	Other liabilities	3.9
Total interest rate derivatives		56.6		46.7		8.0		9.8
Commodity derivatives	Derivative assets	51.9	Derivative assets	150.6	Derivative liabilities	133.2	Derivative liabilities	253.5
Commodity derivatives	Other assets	0.2	Other assets	--	Other liabilities	2.1	Other liabilities	0.2
Total commodity derivatives (1)		52.1		150.6		135.3		253.7
Foreign currency derivatives (2)	Derivative assets	0.3	Derivative assets	9.3	Derivative liabilities	--	Derivative liabilities	--
Total derivatives designated as hedging instruments		$ 109.0		$ 206.6		$ 143.3		$ 263.5
Derivatives not designated as hedging instruments:								
Commodity derivatives	Derivative assets	$ 124.1	Derivative assets	$ 50.9	Derivative liabilities	$ 125.4	Derivative liabilities	$ 43.4
Commodity derivatives	Other assets	1.1	Other assets	--	Other liabilities	2.4	Other liabilities	--
Total commodity derivatives		125.2		50.9		127.8		43.4
Foreign currency derivatives	Derivative assets	--	Derivative assets	--	Derivative liabilities	--	Derivative liabilities	0.1
Total derivatives not designated as hedging instruments		$ 125.2		$ 50.9		$ 127.8		$ 43.5

(1) Represent commodity derivative transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.
(2) Relates to the hedging of our exposure to fluctuations in the foreign currency exchange rate related to our Canadian NGL marketing subsidiary.

The following tables present the effect of our derivative instruments designated as fair value hedges on our Unaudited Supplemental Condensed Statements of Consolidated Operations for the periods indicated:

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2009	2008	2009	2008
Interest rate derivatives	Interest expense	$ 12.0	$ 4.2	$ (4.2)	$ (1.7)
Commodity derivatives	Revenue	0.6	--	(0.1)	--
Total		$ 12.6	$ 4.2	$ (4.3)	$ (1.7)

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2009	2008	2009	2008
Interest rate derivatives	Interest expense	$ (14.5)	$ (4.2)	$ 1.1	$ 1.7
Commodity derivatives	Revenue	(0.5)	--	0.6	--
Total		$ (15.0)	$ (4.2)	$ 1.7	$ 1.7

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Unaudited Supplemental Condensed Statements of Consolidated Operations for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in OCI on Derivative (Effective Portion)			
	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Interest rate derivatives	$ (8.0)	$ (1.1)	$ 7.1	$ (46.1)
Commodity derivatives – Revenue	(21.3)	(17.4)	44.5	(49.4)
Commodity derivatives – Operating costs and expenses	13.0	(218.7)	(191.4)	(93.9)
Foreign currency derivatives	0.2	--	(10.3)	(1.3)
Total	$ (16.1)	$ (237.2)	$ (150.1)	$ (190.7)

Derivatives in Cash Flow Hedging Relationships	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI to Income (Effective Portion)			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2009	2008	2009	2008
Interest rate derivatives	Interest expense	$ (2.8)	$ --	$ (7.6)	$ 2.5
Commodity derivatives	Revenue	(12.5)	(32.6)	7.2	(58.0)
Commodity derivatives	Operating costs and expenses	(65.3)	(11.3)	(183.5)	7.5
Total		$ (80.6)	$ (43.9)	$ (183.9)	$ (48.0)

Derivatives in Cash Flow Hedging Relationships	Location of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivative	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2009	2008	2009	2008
Interest rate derivatives	Interest expense	$ --	$ --	$ --	$ (3.6)
Commodity derivatives	Revenue	0.8	--	0.1	--
Commodity derivatives	Operating costs and expenses	(1.0)	(5.6)	(2.3)	(2.9)
Total		$ (0.2)	$ (5.6)	$ (2.2)	$ (6.5)

Over the next twelve months, we expect to reclassify $11.4 million of accumulated other comprehensive loss ("AOCI") attributable to interest rate derivative instruments to earnings as an increase to interest expense. Likewise, we expect to reclassify $81.3 million of AOCI attributable to commodity derivative instruments to earnings, $32.1 million as an increase in operating costs and expenses and $49.2 million as a reduction in revenues.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Unaudited Supplemental Condensed Statements of Consolidated operations for the periods indicated:

Derivatives Not Designated as Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2009	2008	2009	2008
Commodity derivatives (1)	Revenue	$ (5.4)	$ 38.3	$ 26.6	$ 35.9
Commodity derivatives	Operating costs and expenses	--	1.9	(0.1)	(7.1)
Total		$ (5.4)	$ 40.2	$ 26.5	$ 28.8

(1) Amounts for the three and nine months ended September 30, 2009 include $0.9 million and $3.8 million of gains on derivatives that were excluded from fair value hedging relationships, respectively.

Fair Value Measurements

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

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

The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

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

§ Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, the time value of money, volatility factors, current market and contractual prices for the underlying instruments and other relevant economic measures. Substantially all of these assumptions are (i) observable in the marketplace throughout the full term of the instrument, (ii) can be derived from observable data or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Our Level 2 fair values primarily consist of commodity financial instruments such as forwards, swaps and other instruments transacted on an exchange or over the counter. The fair values of these derivatives are based on observable price quotes for similar products and locations. The value of our interest rate derivatives are valued by using appropriate financial models with the implied forward London Interbank Offered Rate yield curve for the same period as the future interest swap settlements.

§ Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Our Level 3 fair values largely consist of ethane and normal butane-based contracts with a range of two to twelve months in term. We rely on broker quotes for these products.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities measured on a recurring basis at September 30, 2009. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value assets and liabilities, in addition to their placement within the fair value hierarchy levels.

	Level 1	Level 2	Level 3	Total
Financial assets:				
Interest rate derivative instruments	$ --	$ 56.6	$ --	$ 56.6
Commodity derivative instruments	10.9	153.3	13.1	177.3
Foreign currency derivative instruments	--	0.3	--	0.3
Total	$ 10.9	$ 210.2	$ 13.1	$ 234.2
Financial liabilities:				
Interest rate derivative instruments	$ --	$ 8.0	$ --	$ 8.0
Commodity derivative instruments	36.7	212.6	13.8	263.1
Total	$ 36.7	$ 220.6	$ 13.8	$ 271.1

he following table sets forth a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities for the periods presented:

	For the Nine Months Ended September 30,	
	2009	2008
Balance, January 1	$ 32.4	$ (5.1)
Total gains (losses) included in:		
Net income (1)	12.9	(1.8)
Other comprehensive income (loss)	1.5	2.4
Purchases, issuances, settlements	(12.3)	1.9
Balance, March 31	34.5	(2.6)
Total gains (losses) included in:		
Net income (1)	7.7	0.3
Other comprehensive income	(23.1)	(2.4)
Purchases, issuances, settlements	(8.1)	--
Transfer in/out of Level 3	(0.2)	--
Balance, June 30	10.8	(4.7)
Total gains (losses) included in:		
Net income (1)	7.6	(0.6)
Other comprehensive income	(10.1)	23.1
Purchases, issuances, settlements	(6.7)	2.2
Transfer in/out of Level 3	(2.3)	--
Balance, September 30	$ (0.7)	$ 20.0

(1) There were unrealized losses of $3.3 million and $3.5 million included in these amounts for the three and nine months ended September 30, 2009, respectively. There were unrealized gains of $1.5 million and $1.9 million included in these amounts for the three and nine months ended September 30, 2008, respectively.

Nonfinancial Assets and Liabilities

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment). The following table presents the estimated fair value of certain assets carried on our Unaudited Supplemental Condensed Consolidated Balance Sheet by caption for which a nonrecurring change in fair value has been recorded during the period:

	Level 3	Impairment Charges
Property, plant and equipment (see Note 6)	$ 21.9	$ 20.6
Intangible assets (see Note 9)	0.6	0.6
Goodwill (see Note 9)	--	1.3
Other current assets	1.0	2.1
Total	$ 23.5	$ 24.6

Using appropriate valuation techniques, we adjusted the carrying value of certain river terminal and marine barge assets to $20.5 million and recorded a non-cash impairment charge of $21.0 million during the third quarter of 2009. In addition, we recorded an impairment charge of $1.3 million related to goodwill. These charges are reflected in operating costs and expenses for the three and nine months ended September 30, 2009. The fair value adjustment was allocated to property, plant and equipment, intangible assets and other current assets. The current level of throughput volumes at certain river terminals and the suspension of three new proposed river terminals were contributing factors that led to the impairment charges associated with the terminal assets. A determination that certain marine barges were obsolete resulted in the remaining impairment charges. Our fair value estimates for the terminal and marine assets were based primarily on an evaluation of the future cash flows associated with each asset. See Note 15 for information regarding a related $28.7 million charge for contractual obligations associated with the terminal assets.

Using appropriate valuation techniques, we adjusted the carrying value of an idle river terminal to $3.0 million and recorded a non-cash impairment charge of $2.3 million during the second quarter of 2009. This charge is included in operating costs and expenses for the nine months ended September 30, 2009. The fair value adjustment was allocated to plant, property and equipment.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

	September 30, 2009	December 31, 2008
Working inventory (1)	$ 533.3	$ 211.9
Forward sales inventory (2)	687.3	193.1
Total inventory	$ 1,220.6	$ 405.0

(1) Working inventory is comprised of inventories of natural gas, crude oil, refined products, lubrication oils, NGLs and certain petrochemical products that are either available-for-sale or used in the provision for services.
(2) Forward sales inventory consists of identified natural gas, crude oil and NGL volumes dedicated to the fulfillment of forward sales contracts. As a result of energy market conditions, we significantly increased our physical inventory purchases and related forward physical sales commitments during 2009. In general, the significant increase in volumes dedicated to forward physical sales contracts improves the overall utilization and profitability of our fee-based assets.

Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection costs, demurrage charges and other related costs. Inventories are valued at the lower of average cost or market.

Operating costs and expenses, as presented on our Unaudited Supplemental Condensed Statements of Consolidated Operations, include cost of sales amounts related to the sale of inventories. Our costs of sales amounts were $5.58 billion and $9.4 billion for the three months ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009 and 2008, our costs of sales amounts were $13.82 billion and $26.33 billion, respectively. The decrease in cost of sales period-to-period is primarily due to lower energy commodity prices associated with our marketing activities.

Due to fluctuating commodity prices, we recognize lower of average cost or market ("LCM") adjustments when the carrying value of our available-for-sale inventories exceed their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized, and reflected in operating costs and expenses as presented on our Unaudited Supplemental Condensed Statements of Consolidated Operations. LCM adjustments may be mitigated or offset through the use of commodity hedging instruments to the extent such instruments affect net realizable value. See Note 4 for a description of our commodity hedging activities. For the three months ended September 30, 2009 and 2008, we recognized LCM adjustments of $0.5 million and $45.8 million, respectively. We recognized LCM adjustments of $8.6 million and $50.7 million for the nine months ended September 30, 2009 and 2008, respectively.

Note 6. Property, Plant and Equipment

Our property, plant and equipment values and accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	September 30, 2009	December 31, 2008
Plants and pipelines (1)	3-45 (5)	$ 16,958.5	$ 15,266.7
Underground and other storage facilities (2)	5-40 (6)	1,254.9	1,203.9
Platforms and facilities (3)	20-31	637.6	634.8
Transportation equipment (4)	3-10	56.3	50.9
Marine vessels	20-30	527.0	453.0
Land		260.2	254.5
Construction in progress		1,226.8	2,015.4
Total		20,921.3	19,879.2
Less accumulated depreciation		3,624.3	3,146.4
Property, plant and equipment, net		$ 17,297.0	$ 16,732.8

(1) Plants and pipelines include processing plants; NGL, petrochemical, crude oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.
(2) Underground and other storage facilities include underground product storage caverns; storage tanks; water wells; and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets.
(4) Transportation equipment includes vehicles and similar assets used in our operations.
(5) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines and related equipment, 18-45 years (with some equipment at 5 years); terminal facilities, 10-35 years; delivery facilities, 20-40 years; office furniture and equipment, 3-20 years; buildings, 20-40 years; and laboratory and shop equipment, 5-35 years.
(6) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 20-35 years (with some components at 5 years); storage tanks, 10-40 years; and water wells, 25-35 years (with some components at 5 years).

In August 2008, our wholly owned subsidiaries, together with Oiltanking Holding Americas, Inc. (“Oiltanking”) formed the Texas Offshore Port System partnership (“TOPS”). Effective April 16, 2009, our wholly owned subsidiaries dissociated from TOPS. As a result, operating costs and expenses and net income for the nine months ended September 30, 2009 include a non-cash charge of $68.4 million. This loss represents the forfeiture of our cumulative investment in TOPS through the date of dissociation and reflects our capital contributions to TOPS for construction in progress amounts.

TOPS was a consolidated subsidiary of ours prior to the dissociation. The effect of deconsolidation was to remove the accounts of TOPS, including Oiltanking’s noncontrolling interest of $33.4 million, from our books and records, after reflecting the $68.4 million aggregate write-off of the investment. See Note 15 for information regarding expense amounts recognized in the third quarter of 2009 in connection with a settlement agreement involving TOPS.

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Depreciation expense (1)	$ 175.3	$ 148.8	$ 509.2	$ 431.8
Capitalized interest (2)	11.4	21.6	39.5	67.1

(1) Depreciation expense is a component of costs and expenses as presented in our Unaudited Supplemental Condensed Statements of Consolidated Operations.
(2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.

We recorded $18.3 million and $20.6 million of non-cash impairment charges related to our Petrochemical & Refined Products Services segment during the three and nine months ended September 30, 2009, respectively. See Note 4 for additional information.

Asset Retirement Obligations

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of certain tangible long-lived assets that result from acquisitions, construction, development and/or normal operations. The following table presents information regarding our AROs since December 31, 2008.

ARO liability balance, December 31, 2008	$	42.2
Liabilities incurred		0.4
Liabilities settled		(15.2)
Revisions in estimated cash flows		23.6
Accretion expense		2.1
ARO liability balance, September 30, 2009	$	53.1

The increase in our ARO liability balance during 2009 primarily reflects revised estimates of the cost to comply with regulatory abandonment obligations associated with our offshore facilities in the Gulf of Mexico. We incurred $13.6 million of costs through September 30, 2009 as a result of ARO settlement activities associated with certain pipeline laterals and a platform located in the Gulf of Mexico.

Our consolidated property, plant and equipment at September 30, 2009 and December 31, 2008 includes $26.3 million and $11.7 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. Based on information currently available, we estimate that accretion expense will approximate $0.9 million for the fourth quarter of 2009, $3.6 million for each of 2010 and 2011, $3.9 million for 2012 and $4.2 million for 2013.

Note 7. Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. Our investments in unconsolidated affiliates are grouped according to the business segment to which they relate. See Note 12 for a general discussion of our business segments. The following table shows our investments in unconsolidated affiliates at the dates indicated.

	Ownership Percentage at September 30, 2009	September 30, 2009	December 31, 2008
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 33.1	$ 37.7
K/D/S Promix, L.L.C. ("Promix")	50%	47.8	46.4
Baton Rouge Fractionators LLC	32.2%	23.6	24.2
Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu")	49%	37.4	36.0
Onshore Natural Gas Pipelines & Services:			
Evangeline (1)	49.5%	5.4	4.5
White River Hub, LLC	50%	27.1	21.4
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company ("Seaway")	50%	181.0	186.2
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C. ("Poseidon")	36%	61.3	60.2
Cameron Highway Oil Pipeline Company ("Cameron Highway")	50%	243.2	250.9
Deepwater Gateway, L.L.C.	50%	102.8	104.8
Neptune Pipeline Company, L.L.C. ("Neptune")	25.7%	54.4	52.7
Nemo Gathering Company, LLC	33.9%	--	0.4
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	11.4	12.6
La Porte (2)	50%	3.5	3.9
Centennial Pipeline LLC ("Centennial")	50%	66.8	69.7
Other	25%	0.5	0.3
Total		$ 899.3	$ 911.9

(1) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(2) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in unconsolidated affiliates. At September 30, 2009 and December 31, 2008, our investments in Promix, Skelly-Belvieu, La Porte, Neptune, Poseidon, Cameron Highway, Seaway and Centennial included excess cost amounts totaling $70.5 million and $75.6 million, respectively, all of which were attributable to the fair value of the underlying tangible assets of these entities exceeding their book carrying values at the time of our acquisition of interests in these entities. To the extent that we attribute all or a portion of an excess cost amount to higher fair values, we amortize such excess cost as a reduction in equity earnings in a manner similar to depreciation. To the extent we attribute an excess cost amount to goodwill, we do not amortize this amount but it is subject to evaluation for impairment. Amortization of excess cost amounts was $1.7 million and $1.8 million for the three months ended September 30, 2009 and 2008, respectively. For each of the nine months ended September 30, 2009 and 2008, amortization of such amounts was $5.1 million.

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
NGL Pipelines & Services	$ 4.0	$ 3.0	$ 7.5	$ 2.3
Onshore Natural Gas Pipelines & Services	1.4	0.4	3.9	0.8
Onshore Crude Oil Pipelines & Services	1.2	2.7	7.4	9.9
Offshore Pipelines & Services	10.6	6.0	22.1	27.9
Petrochemical & Refined Products Services	(2.2)	(2.0)	(8.9)	(9.1)
Total	$ 15.0	$ 10.1	$ 32.0	$ 31.8

Summarized Financial Information of Unconsolidated Affiliates

The following tables present unaudited income statement data for our current unconsolidated affiliates, aggregated by business segment, for the periods indicated (on a 100% basis):

	Summarized Income Statement Information for the Three Months Ended					
	September 30, 2009			September 30, 2008		
	Revenues	Operating Income	Net Income (Loss)	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 60.0	$ 10.9	$ 11.2	$ 75.1	$ 9.7	$ 6.8
Onshore Natural Gas Pipelines & Services	54.5	2.9	2.7	130.3	2.0	0.8
Onshore Crude Oil Pipelines & Services	20.7	6.8	6.9	24.6	11.6	11.7
Offshore Pipelines & Services	43.2	24.7	24.0	31.9	12.9	11.9
Petrochemical & Refined Products Services	12.2	2.2	(0.3)	15.0	3.6	0.9

	Summarized Income Statement Information for the Nine Months Ended					
	September 30, 2009			September 30, 2008		
	Revenues	Operating Income	Net Income (Loss)	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 161.7	$ 23.7	$ 24.2	$ 217.8	$ 17.7	$ 15.1
Onshore Natural Gas Pipelines & Services	137.1	8.0	7.6	315.5	5.5	1.5
Onshore Crude Oil Pipelines & Services	62.2	25.6	25.6	72.5	37.3	37.4
Offshore Pipelines & Services	106.4	39.2	37.7	115.0	62.4	57.2
Petrochemical & Refined Products Services	39.5	4.7	(3.0)	46.1	8.5	0.4

Note 8. Business Combinations

In May 2009, we acquired certain rail and truck terminal facilities located in Mont Belvieu, Texas from Martin Midstream Partners L.P ("Martin"). Cash consideration paid for this business combination was $23.7 million, all of which was recorded as additions to property, plant and equipment. We used our revolving credit facility to finance this acquisition.

In June 2009, TEPPCO expanded its marine transportation business with the acquisition of 19 tow boats and 28 tank barges from TransMontaigne Product Services Inc. for $50.0 million in cash. The acquired vessels provide marine vessel fueling services for cruise liners and cargo ships, referred to as bunkering, and other ship-assist services and transport fuel oil for electric generation plants. The newly acquired assets are generally supported by contracts that have a three to five year term and are based primarily in Miami, Florida, with additional assets located in Mobile, Alabama, and Houston, Texas. The cost of the acquisition has been recorded as property, plant and equipment based on estimated fair values. We used TEPPCO's revolving credit facility to finance this acquisition.

The results of operations of these acquisitions are included in our supplemental consolidated financial statements beginning at the date of acquisition. These acquisitions were accounted for as business combinations using the acquisition method of accounting. All of the assets acquired in these transactions were recognized at their acquisition-date fair values, while transaction costs associated with these transactions were expensed as incurred. Such fair values have been developed using recognized business valuation techniques.

On a pro forma consolidated basis, our revenues, costs and expenses, operating income, net income and earnings per unit amounts would not have differed materially from those we actually reported for the three and nine months ended September 30, 2009 and 2008 due to immaterial nature of our 2009 business combination transactions.

Note 9. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets by segment at the dates indicated:

	September 30, 2009			December 31, 2008		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 237.4	$ (82.2)	$ 155.2	$ 237.4	$ (68.7)	$ 168.7
Contract-based intangibles	320.5	(151.7)	168.8	320.3	(137.6)	182.7
Subtotal	557.9	(233.9)	324.0	557.7	(206.3)	351.4
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	372.0	(119.1)	252.9	372.0	(103.2)	268.8
Gas gathering agreements	464.0	(234.1)	229.9	464.0	(213.1)	250.9
Contract-based intangibles	101.3	(43.1)	58.2	101.3	(36.6)	64.7
Subtotal	937.3	(396.3)	541.0	937.3	(352.9)	584.4
Onshore Crude Oil Pipelines & Services:						
Contract-based intangibles	10.0	(3.4)	6.6	10.0	(3.1)	6.9
Subtotal	10.0	(3.4)	6.6	10.0	(3.1)	6.9
Offshore Pipelines & Services:						
Customer relationship intangibles	205.8	(101.8)	104.0	205.8	(90.7)	115.1
Contract-based intangibles	1.2	(0.2)	1.0	1.2	(0.1)	1.1
Subtotal	207.0	(102.0)	105.0	207.0	(90.8)	116.2
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.6	(17.6)	87.0	104.9	(13.8)	91.1
Contract-based intangibles	42.0	(12.4)	29.6	41.1	(8.2)	32.9
Subtotal	146.6	(30.0)	116.6	146.0	(22.0)	124.0
Total	$ 1,858.8	$ (765.6)	$ 1,093.2	$ 1,858.0	$ (675.1)	$ 1,182.9

The following table presents the amortization expense of our intangible assets by business segment for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
NGL Pipelines & Services	$ 9.4	$ 10.1	$ 27.6	$ 30.8
Onshore Natural Gas Pipelines & Services	13.9	15.2	43.4	46.9
Onshore Crude Oil Pipelines & Services	0.1	0.1	0.3	0.3
Offshore Pipelines & Services	3.6	4.1	11.2	12.9
Petrochemical & Refined Products Services	2.7	2.7	8.0	7.4
Total	$ 29.7	$ 32.2	$ 90.5	$ 98.3

Based on information currently available, we estimate that amortization expense will approximate $29.7 million for the fourth quarter 2009, $113.8 million for 2010, $106.3 million for 2011, $90.8 million for 2012 and $83.7 million for 2013.

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. We do not amortize goodwill; however, we test goodwill for impairment annually, or more frequently if circumstances indicate that it is more likely than not that the fair value of goodwill is less than its carrying value. The following table summarizes our goodwill amounts by business segment at the dates indicated:

	September 30, 2009	December 31, 2008
NGL Pipelines & Services	$ 341.2	$ 341.2
Onshore Natural Gas Pipelines & Services	284.9	284.9
Onshore Crude Oil Pipelines & Services	303.0	303.0
Offshore Pipelines & Services	82.1	82.1
Petrochemical & Refined Products Services	1,007.1	1,008.4
Total	$ 2,018.3	$ 2,019.6

Note 10. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated:

	September 30, 2009	December 31, 2008
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due November 2012	$ 638.0	$ 800.0
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010 (1)	54.0	54.0
Petal GO Zone Bonds, variable rate, due August 2037	57.5	57.5
Yen Term Loan, 4.93% fixed-rate, due March 2009 (2)	--	217.6
Senior Notes B, 7.50% fixed-rate, due February 2011	450.0	450.0
Senior Notes C, 6.375% fixed-rate, due February 2013	350.0	350.0
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes F, 4.625% fixed-rate, due October 2009 (1)	500.0	500.0
Senior Notes G, 5.60% fixed-rate, due October 2014	650.0	650.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes I, 5.00% fixed-rate, due March 2015	250.0	250.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes K, 4.950% fixed-rate, due June 2010 (1)	500.0	500.0
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes M, 5.65% fixed-rate, due April 2013	400.0	400.0
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes O, 9.75% fixed-rate, due January 2014	500.0	500.0
Senior Notes P, 4.60% fixed-rate, due August 2012	500.0	--
TEPPCO senior debt obligations: (3)		
TEPPCO Revolving Credit Facility, variable rate, due December 2012	791.7	516.7
TEPPCO Senior Notes, 7.625% fixed-rate, due February 2012	500.0	500.0
TEPPCO Senior Notes, 6.125% fixed-rate, due February 2013	200.0	200.0
TEPPCO Senior Notes, 5.90% fixed-rate, due April 2013	250.0	250.0
TEPPCO Senior Notes, 6.65% fixed-rate, due April 2018	350.0	350.0
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	400.0	400.0
Duncan Energy Partners' debt obligations:		
DEP Revolving Credit Facility, variable rate, due February 2011	180.5	202.0
DEP Term Loan, variable rate, due December 2011	282.3	282.3
Total principal amount of senior debt obligations	10,404.0	10,030.1
EPO Junior Subordinated Notes A, fixed/variable rate, due August 2066	550.0	550.0
EPO Junior Subordinated Notes B, fixed/variable rate, due January 2068	682.7	682.7
TEPPCO Junior Subordinated Notes, fixed/variable rate, due June 2067	300.0	300.0
Total principal amount of senior and junior debt obligations	11.936.7	11,562.8
Other, non-principal amounts:		
Change in fair value of debt-related derivative instruments	47.6	51.9
Unamortized discounts, net of premiums	(12.1)	(12.6)
Unamortized deferred net gains related to terminated interest rate swaps	27.0	35.8
Total other, non-principal amounts	62.5	75.1
Total long-term debt	$ 11,999.2	$ 11,637.9
Letters of credit outstanding	$ 109.3	$ 1.0

(1) In accordance with ASC 470, Debt, long-term and current maturities of debt reflect the classification of such obligations at September 30, 2009 after taking into consideration EPO's (i) $1.1 billion issuance of Senior Notes in October 2009 and (ii) ability to use available borrowing capacity under its Multi-Year Revolving Credit Facility.
(2) The Yen Term Loan matured on March 30, 2009.
(3) In October 2009, EPO completed an exchange offer for TEPPCO notes (see below).

Parent-Subsidiary Guarantor Relationships

Enterprise Products Partners L.P. acts as guarantor of the consolidated debt obligations of EPO with the exception of the DEP Revolving Credit Facility and the DEP Term Loan. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation.

Letters of Credit

At September 30, 2009, EPO had an outstanding $50.0 million letter of credit relating to its commodity derivative instruments and a $58.3 million letter of credit related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's credit facilities. In addition, at September 30, 2009, Duncan Energy Partners had an outstanding letter of credit in the amount of $1.0 million which reduces the amount available for borrowing under its credit facility.

EPO's Debt Obligations

Apart from that discussed below, there have been no significant changes in the terms of our debt obligations since those reported in this Current Report on Form 8-K under Exhibit 99.2.

$200.0 Million Term Loan. In April 2009, EPO entered into a $200.0 Million Term Loan, which was subsequently repaid and terminated in June 2009 using funds from the issuance of Senior Notes P (see below).

Senior Notes P. In June 2009, EPO issued $500.0 million in principal amount of 3-year senior unsecured notes ("Senior Notes P"). Senior Notes P were issued at 99.95% of their principal amount, have a fixed interest rate of 4.60% and mature on August 1, 2012. Net proceeds from the issuance of Senior Notes P were used (i) to repay amounts borrowed under the $200 Million Term Loan, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general partnership purposes.

Senior Notes P rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes P are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

364-Day Revolving Credit Facility. In November 2008, EPO executed a standby 364-Day Revolving Credit Agreement (the "364-Day Facility") that had a borrowing capacity of $375.0 million. The 364-Day Facility was terminated in June 2009 under its terms as a result of the issuance of Senior Notes P. No amounts were borrowed under this standby facility through its termination date.

Senior Notes Q and R. In October 2009, EPO issued $500.0 million in principal amount of 10-year senior unsecured notes ("Senior Notes Q") and $600.0 million in principal amount of 30-year senior unsecured notes ("Senior Notes R"). EPO used a portion of the net proceeds it received from the issuance of Senior Notes Q and R to repay its $500.0 million in principal amount unsecured notes ("Senior Notes F") that matured in October 2009. See Note 19 for additional information regarding these debt issuances.

TEPPCO's Debt Obligations

Exchange Offers for TEPPCO Notes. In September 2009, EPO commenced offers to exchange all outstanding notes issued by TEPPCO for a corresponding series of new notes to be issued by EPO and guaranteed by Enterprise Products Partners L.P. The aggregate principal amount of the TEPPCO notes subject to the exchange was $2 billion. The exchange offer was completed on October 27, 2009, resulting in the exchange of approximately $1.95 billion of new EPO notes for existing TEPPCO notes. See Note 19 for additional information regarding this exchange offer.

Upon the consummation of the TEPPCO Merger, EPO repaid and terminated indebtedness under the TEPPCO Revolving Credit Facility.

Dixie Revolving Credit Facility

The Dixie Revolving Credit Facility was terminated in January 2009. As of December 31, 2008, there were no debt obligations outstanding under this facility.

Covenants

We were in compliance with the covenants of our consolidated debt agreements at September 30, 2009.

Information Regarding Variable Interest Rates Paid

The following table shows the weighted-average interest rate paid on our consolidated variable-rate debt obligations during the nine months ended September 30, 2009.

	Weighted-Average Interest Rate Paid
EPO's Multi-Year Revolving Credit Facility	0.97%
DEP Revolving Credit Facility	1.64%
DEP Term Loan	1.20%
Petal GO Zone Bonds	0.76%
TEPPCO Revolving Credit Facility	0.86%

Consolidated Debt Maturity Table

The following table presents the scheduled contractual maturities of principal amounts of our debt obligations for the next five years and in total thereafter.

2009 (1)	$	500.0
2010 (1)		554.0
2011		912.8
2012		2,429.7
2013		1,200.0
Thereafter		6,340.2
Total scheduled principal payments	$	11,936.7

(1) Long-term and current maturities of debt reflect the classification of such obligations on our Unaudited Supplemental Condensed Consolidated Balance Sheet at September 30, 2009 after taking into consideration EPO's (i) $1.1 billion issuance of Senior Notes in October 2009 and (ii) ability to use available borrowing capacity under its Multi-Year Revolving Credit Facility.

Debt Obligations of Unconsolidated Affiliates

We have three unconsolidated affiliates with long-term debt obligations. The following table shows (i) the ownership interest in each entity at September 30, 2009, (ii) total debt of each unconsolidated affiliate at September 30, 2009 (on a 100% basis to the unconsolidated affiliate) and (iii) the corresponding scheduled maturities of such debt:

			Scheduled Maturities of Debt					
	Ownership Interest	Total	2009	2010	2011	2012	2013	After 2013
Poseidon	36%	$ 92.0	$ --	$ --	$ 92.0	$ --	$ --	$ --
Evangeline	49.5%	15.7	5.0	3.2	7.5	--	--	--
Centennial	50%	122.4	2.4	9.1	9.0	8.9	8.6	84.4
Total		$ 230.1	$ 7.4	$ 12.3	$ 108.5	$ 8.9	$ 8.6	$ 84.4

The credit agreements of these unconsolidated affiliates contain various affirmative and negative covenants, including financial covenants. These businesses were in compliance with such covenants at September 30, 2009. The credit agreements of these unconsolidated affiliates also restrict their ability to pay cash dividends or distributions if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend or distribution is scheduled to be paid.

There have been no significant changes in the terms of the debt obligations of our unconsolidated affiliates since those reported in this Current Report on Form 8-K under Exhibit 99.2.

Note 11. Equity and Distributions

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Fifth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the "Partnership Agreement"). We are managed by our general partner, EPGP.

Equity Offerings and Registration Statements

We have a universal shelf registration statement on file with the SEC that allows us to issue an unlimited amount of debt and equity securities for general partnership purposes. In January 2009, we issued 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit under this registration statement. We used the net proceeds of $225.6 million from the January 2009 equity offering to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes. In June 2009, EPO issued $500.0 million in principal amount of Senior Notes P under this registration statement. Net proceeds from this senior note offering were used to repay the $200.0 Million Term Loan, to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

In September 2009, we issued 8,337,500 common units (including an over-allotment of 1,087,500 common units) to the public at an offering price of $28.00 per unit under this registration statement. We used the net proceeds of $226.4 million from the September 2009 equity offering to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes. In October 2009, EPO issued $1.1 billion in principal amount of Senior Notes Q and R under this registration statement. Net proceeds from this senior note offering were used to repay $500.0 million in aggregate principal amount of Senior Notes F that matured in October 2009, to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

We also have a registration statement on file with the SEC authorizing the issuance of up to 40,000,000 common units in connection with our distribution reinvestment plan ("DRIP"). A total of 32,202,131 common units have been issued under this registration statement through September 30, 2009.

In addition, we have a registration statement on file related to our employee unit purchase plan ("EUPP"), under which we can issue up to 1,200,000 common units. A total of 792,809 common units have been issued to employees under this plan through September 30, 2009.

On September 4, 2009, we agreed to issue 5,940,594 common units in a private placement to EPCO Holdings, Inc., a privately held affiliate controlled by Dan L. Duncan, for $150.0 million, or $25.25 per unit. In accordance with the terms of the private placement, as approved by the Audit, Conflicts and Governance ("ACG") Committee of EPGP's Board of Directors on September 1, 2009, the per unit purchase price of $25.25 was calculated based on a five percent discount to the five-day volume weighted average price ("5-Day VWAP") of our common units, as reported by the NYSE at the close of business on September 4, 2009. The 5-Day VWAP was based on (i) the closing price for the common units on the

NYSE for each of the trading days in such five-day period and (ii) the total trading volume for the common units reported by the NYSE for each such trading day. The common units were issued on September 8, 2009.

The following table reflects the number of common units issued and the net proceeds received from underwritten and other common unit offerings completed during the nine months ended September 30, 2009:

		Net Proceeds from Sale of Common Units		
	Number of Common Units Issued	Contributed by Limited Partners	Contributed by General Partner	Total Net Proceeds
January underwritten offering	10,590,000	$ 225.6	$ 4.6	$ 230.2
February DRIP and EUPP	3,679,163	78.9	1.6	80.5
May DRIP and EUPP	3,671,679	86.1	1.8	87.9
August DRIP and EUPP	3,521,754	93.2	1.8	95.0
September private placement	5,940,594	150.0	3.1	153.1
September underwritten offering	8,337,500	226.4	4.6	231.0
Total 2009	35,740,690	$ 860.2	$ 17.5	$ 877.7

Net proceeds from the issuance of common units during 2009 have been used to temporarily reduce borrowings under EPO’s Multi-Year Revolving Credit Facility and for general partnership purposes.

Summary of Changes in Outstanding Units

The following table summarizes changes in our outstanding units since December 31, 2008:

	Common Units	Restricted Common Units	Treasury Units
Balance, December 31, 2008	439,354,731	2,080,600	--
Common units issued in connection with underwritten offerings	18,927,500	--	--
Common units issued in connection with private placement	5,940,594	--	--
Common units issued in connection with DRIP and EUPP	10,872,596	--	--
Common units issued in connection with equity awards	18,500	--	--
Restricted units issued	--	1,016,950	--
Forfeiture of restricted units	--	(194,400)	--
Conversion of restricted units to common units	244,300	(244,300)	--
Acquisition of treasury units	(64,223)	--	64,223
Cancellation of treasury units	--	--	(64,223)
Balance, September 30, 2009	475,293,998	2,658,850	--

Summary of Changes in Limited Partners' Equity

The following table details the changes in limited partners' equity since December 31, 2008:

	Common Units	Restricted Common Units	Total
Balance, December 31, 2008	$ 6,036.9	$ 26.2	$ 6,063.1
Net income	501.9	2.7	504.6
Operating leases paid by EPCO	0.5	--	0.5
Cash distributions to partners	(731.5)	(3.7)	(735.2)
Unit option reimbursements to EPCO	(0.5)	--	(0.5)
Net proceeds from issuance of common units	860.2	--	860.2
Proceeds from exercise of unit options	0.5	--	0.5
Acquisition of treasury units	--	(1.8)	(1.8)
Amortization of equity awards	2.8	10.7	13.5
Balance, September 30, 2009	$ 6,670.8	$ 34.1	$ 6,704.9

Distributions to Partners

We paid EPGP incentive distributions of $38.1 million and $32.0 million during the three months ended September 30, 2009 and 2008, respectively. During the nine months ended September 30, 2009 and 2008, we paid incentive distributions of $109.9 million and $92.8 million, respectively, to EPGP.

We paid aggregate distributions to our unitholders and our general partner of $860.1 million during the nine months ended September 30, 2009. These distributions pertained to the nine month period ended June 30, 2009 (i.e., the fourth quarter of 2008, and first and second quarters of 2009). On November 5, 2009, we paid a quarterly cash distribution of $0.5525 per unit with respect to the third quarter of 2009, to unitholders of record at the close of business on October 30, 2009, which included former TEPPCO unitholders who received our common units upon completion of the TEPPCO Merger. See Note 19 for additional information regarding the TEPPCO Merger.

Accumulated Other Comprehensive Loss

The following table presents the components of AOCI at the dates indicated:

	September 30, 2009	December 31, 2008
Commodity derivative instruments (1)	$ (84.7)	$ (114.1)
Interest rate derivative instruments (1)	(27.2)	(41.9)
Foreign currency derivative instruments (1)	0.3	10.6
Foreign currency translation adjustment (2)	0.4	(1.3)
Pension and postretirement benefit plans	(0.8)	(0.8)
Subtotal	(112.0)	(147.5)
Amount attributable to noncontrolling interest	44.9	50.3
Total accumulated other comprehensive loss in partners' equity	$ (67.1)	$ (97.2)

(1) See Note 4 for additional information regarding these components of accumulated other comprehensive loss.
(2) Relates to transactions of our Canadian NGL marketing subsidiary.

Noncontrolling Interest

The following table presents the components of noncontrolling interest as presented on our Unaudited Supplemental Condensed Consolidated Balance Sheets at the dates indicated:

	September 30, 2009	December 31, 2008
Former owners of TEPPCO (1)	$ 2,608.7	$ 2,827.6
Limited partners of Duncan Energy Partners (2)	416.9	281.1
Joint venture partners (3)	108.5	148.0
AOCI attributable to noncontrolling interest	(44.9)	(50.3)
Total noncontrolling interest on consolidated balance sheets	$ 3,089.2	$ 3,206.4

(1) Represents former ownership interests in TEPPCO and TEPPCO GP (see Note 1 - "Basis of Financial Statement Presentation").
(2) Represents non-affiliate public unitholders of Duncan Energy Partners. The increase in noncontrolling interest between periods is attributable to Duncan Energy Partners' equity offering in June 2009 (see Note 13).
(3) Represents third-party ownership interests in joint ventures that we consolidate, including Seminole Pipeline Company, Tri-States Pipeline L.L.C., Independence Hub LLC and Wilprise Pipeline Company LLC. The balance at December 31, 2008, included $35.6 million related to Oiltanking's ownership interest in TOPS, from which our wholly owned subsidiaries dissociated in April 2009 (see Note 6).

As a result of the dissociation of our wholly owned subsidiaries from TOPS (see Note 6), we discontinued the consolidation of TOPS during the second quarter of 2009. The effect of deconsolidation was to remove the accounts of TOPS, including Oiltanking's noncontrolling interest of $33.4 million, from our books and records, after reflecting a $68.4 million aggregate write-off of the investment.

The following table presents the components of net income (loss) attributable to noncontrolling interest as presented on our Unaudited Supplemental Condensed Statements of Consolidated Operations for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Former owners of TEPPCO	$ (42.1)	$ 47.1	$ 48.5	$ 158.8
Limited partners of Duncan Energy Partners	10.1	2.7	21.8	11.8
Joint venture partners	6.9	5.2	20.7	17.5
Total	$ (25.1)	$ 55.0	$ 91.0	$ 188.1

Net income attributable to the former owners of TEPPCO decreased during the three and nine months ended September 30, 2009 relative to the same periods in 2008 by $33.5 million and $66.9 million, respectively, primarily due to charges related to TOPS (see Notes 6 and 15). In addition, TEPPCO recorded $51.0 million in charges during the three months ended September 30, 2009 primarily related to its indefinite suspension of certain river terminal projects (see Notes 4 and 15).

The following table presents cash distributions paid to, and cash contributions from, noncontrolling interest as presented on our Unaudited Supplemental Condensed Statements of Consolidated Cash Flows and Unaudited Supplemental Condensed Statements of Consolidated Equity for the periods indicated:

	For the Nine Months Ended September 30,	
	2009	2008
Cash distributions paid to noncontrolling interest:		
Former owners of TEPPCO	$ 274.5	$ 236.8
Limited partners of Duncan Energy Partners	23.2	18.5
Joint venture partners	26.8	20.7
Total cash distributions paid to noncontrolling interest	$ 324.5	$ 276.0
Cash contributions from noncontrolling interest:		
Former owners of TEPPCO	3.5	271.3
Limited partners of Duncan Energy Partners	137.4	--
Total cash contributions from noncontrolling interest	$ 140.9	$ 271.3

Distributions paid to the limited partners of Duncan Energy Partners and former owners of TEPPCO primarily represent the quarterly cash distributions paid by these entities to their unitholders. Contributions from the limited partners of Duncan Energy Partners and former owners of TEPPCO primarily represent proceeds each entity received from unit offerings.

Duncan Energy Partners issued an aggregate 8,943,400 of its common units in June and July 2009, which generated net proceeds of approximately $137.4 million. Duncan Energy Partners used the net proceeds from its issuance of these units to repurchase and cancel an equal number of its common units beneficially owned by EPO.

Contributions from the former owners of TEPPCO decreased during the nine months ended September 30, 2009 relative to the nine months ended September 30, 2008 due to net proceeds that TEPPCO received from its unit offering in September 2008.

Note 12. Business Segments

As previously mentioned in Note 1, we revised our business segments as a result of the TEPPCO Merger. We have five reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Onshore Crude Oil Pipelines & Services, Offshore Pipelines & Services and Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues (1)	$ 6,789.4	$ 10,499.1	$ 17,110.6	$ 29,544.1
Less: Operating costs and expenses (1)	(6,395.8)	(10,074.3)	(15,796.9)	(28,150.2)
Add: Equity in income (loss) of unconsolidated affiliates (1)	15.0	10.1	32.0	31.8
Depreciation, amortization and accretion in operating costs and expenses (2)	206.0	181.3	602.9	532.3
Impairment charges included in operating costs and expenses (2)	24.0	--	26.3	--
Operating lease expense paid by EPCO (2)	0.2	0.5	0.5	1.6
Gain from asset sales and related transactions in operating costs and expenses (2)	(0.1)	(1.1)	(0.5)	(2.0)
Total segment gross operating margin	$ 638.7	$ 615.6	$ 1,974.9	$ 1,957.6

(1) These amounts are taken from our Unaudited Supplemental Condensed Statements of Consolidated Operations.
(2) These non-cash expenses are taken from the operating activities section of our Unaudited Supplemental Condensed Statements of Consolidated Cash Flows.

A reconciliation of our total segment gross operating margin to operating income and income before provision for income taxes follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Total segment gross operating margin	$ 638.7	$ 615.6	$ 1,974.9	$ 1,957.6
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(206.0)	(181.3)	(602.9)	(532.3)
Impairment charges included in operating costs and expenses	(24.0)	--	(26.3)	--
Operating lease expense paid by EPCO	(0.2)	(0.5)	(0.5)	(1.6)
Gain from asset sales and related transactions in operating costs and expenses	0.1	1.1	0.5	2.0
General and administrative costs	(52.3)	(33.9)	(133.3)	(100.4)
Operating income	356.3	401.0	1,212.4	1,325.3
Other expense, net	(160.8)	(135.2)	(469.8)	(391.1)
Income before provision for income taxes	$ 195.5	$ 265.8	$ 742.6	$ 934.2

Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Reportable Segments						
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:							
Three months ended September 30, 2009	$ 3,141.7	$ 708.1	$ 2,007.0	$ 101.7	$ 720.5	$ --	$ 6,679.0
Three months ended September 30, 2008	4,300.5	886.5	3,994.1	64.9	1,000.1	--	10,246.1
Nine months ended September 30, 2009	7,767.6	2,007.6	5,003.1	247.5	1,662.6	--	16,688.4
Nine months ended September 30, 2008	12,581.9	2,636.3	10,628.9	205.1	2,760.2	--	28,812.4
Revenues from related parties:							
Three months ended September 30, 2009	47.2	60.2	3.0	--	--	--	110.4
Three months ended September 30, 2008	93.6	154.7	4.7	--	--	--	253.0
Nine months ended September 30, 2009	245.3	173.1	3.8	--	--	--	422.2
Nine months ended September 30, 2008	409.2	314.7	7.8	--	--	--	731.7
Intersegment and intrasegment revenues:							
Three months ended September 30, 2009	1,640.5	125.5	11.1	0.4	158.6	(1,936.1)	--
Three months ended September 30, 2008	2,366.9	303.4	23.0	0.4	219.5	(2,913.2)	--
Nine months ended September 30, 2009	4,535.5	392.8	34.7	1.0	393.8	(5,357.8)	--
Nine months ended September 30, 2008	6,541.5	677.3	52.3	1.1	538.0	(7,810.2)	--
Total revenues:							
Three months ended September 30, 2009	4,829.4	893.8	2,021.1	102.1	879.1	(1,936.1)	6,789.4
Three months ended September 30, 2008	6,761.0	1,344.6	4,021.8	65.3	1,219.6	(2,913.2)	10,499.1
Nine months ended September 30, 2009	12,548.4	2,573.5	5,041.6	248.5	2,056.4	(5,357.8)	17,110.6
Nine months ended September 30, 2008	19,532.6	3,628.3	10,689.0	206.2	3,298.2	(7,810.2)	29,544.1
Equity in income (loss) of unconsolidated affiliates:							
Three months ended September 30, 2009	4.0	1.4	1.2	10.6	(2.2)	--	15.0
Three months ended September 30, 2008	3.0	0.4	2.7	6.0	(2.0)	--	10.1
Nine months ended September 30, 2009	7.5	3.9	7.4	22.1	(8.9)	--	32.0
Nine months ended September 30, 2008	2.3	0.8	9.9	27.9	(9.1)	--	31.8
Gross operating margin:							
Three months ended September 30, 2009	403.4	108.4	34.1	22.8	70.0	--	638.7
Three months ended September 30, 2008	342.4	133.0	35.4	16.4	88.4	--	615.6
Nine months ended September 30, 2009	1,118.1	391.5	126.7	83.0	255.6	--	1,974.9
Nine months ended September 30, 2008	970.9	452.8	109.5	133.3	291.1	--	1,957.6
Segment assets:							
At September 30, 2009	6,280.3	5,761.5	391.6	1,488.4	2,148.4	1,226.8	17,297.0
At December 31, 2008	5,622.4	5,223.6	386.9	1,394.5	2,090.0	2,015.4	16,732.8
Investments in unconsolidated affiliates: (see Note 7)							
At September 30, 2009	141.9	32.5	181.0	461.7	82.2	--	899.3
At December 31, 2008	144.3	25.9	186.2	469.0	86.5	--	911.9
Intangible assets, net: (see Note 9)							
At September 30, 2009	324.0	541.0	6.6	105.0	116.6	--	1,093.2
At December 31, 2008	351.4	584.4	6.9	116.2	124.0	--	1,182.9
Goodwill: (see Note 9)							
At September 30, 2009	341.2	284.9	303.0	82.1	1,007.1	--	2,018.3
At December 31, 2008	341.2	284.9	303.0	82.1	1,008.4	--	2,019.6

The following table provides additional information regarding our consolidated revenues (net of adjustments and eliminations) and expenses for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
NGL Pipelines & Services:				
Sales of NGLs	$ 3,015.4	$ 4,212.6	$ 7,527.6	$ 12,433.2
Sales of other petroleum and related products	0.6	0.5	1.5	1.9
Midstream services	172.9	181.0	483.8	556.0
Total	3,188.9	4,394.1	8,012.9	12,991.1
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	585.8	859.2	1,645.4	2,400.4
Midstream services	182.5	182.0	535.3	550.6
Total	768.3	1,041.2	2,180.7	2,951.0
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	1,991.3	3,980.5	4,946.1	10,580.7
Midstream services	18.7	18.3	60.8	56.0
Total	2,010.0	3,998.8	5,006.9	10,636.7
Offshore Pipelines & Services:				
Sales of natural gas	0.3	0.9	0.9	2.5
Sales of other petroleum and related products	2.0	3.7	3.1	10.7
Midstream services	99.4	60.3	243.5	191.9
Total	101.7	64.9	247.5	205.1
Petrochemical Services:				
Sales of other petroleum and related products	597.2	848.4	1,272.0	2,329.2
Midstream services	123.3	151.7	390.6	431.0
Total	720.5	1,000.1	1,662.6	2,760.2
Total consolidated revenues	$ 6,789.4	$ 10,499.1	$ 17,110.6	$ 29,544.1
Consolidated cost and expenses:				
Operating costs and expenses:				
Cost of sales for our marketing activities	$ 5,008.5	$ 8,473.0	$ 12,248.3	$ 23,705.2
Depreciation, amortization and accretion	206.0	181.4	602.8	532.3
Gain on sale of assets and related transactions	(0.1)	(1.1)	(0.5)	(2.0)
Non-cash impairment charge	24.0	--	26.3	--
Other operating costs and expenses	1,157.4	1,421.0	2,920.0	3,914.7
General and administrative costs	52.3	33.9	133.3	100.4
Total consolidated costs and expenses	$ 6,448.1	$ 10,108.2	$ 15,930.2	$ 28,250.6

Note 13. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues from consolidated operations:				
Energy Transfer Equity and subsidiaries	$ 54.5	$ 99.6	$ 266.5	$ 413.0
Unconsolidated affiliates	55.9	153.4	155.7	318.7
Total	$ 110.4	$ 253.0	$ 422.2	$ 731.7
Cost of sales:				
EPCO and affiliates	$ 19.5	$ 10.3	$ 46.4	$ 31.0
Energy Transfer Equity and subsidiaries	100.6	50.6	286.5	119.4
Unconsolidated affiliates	13.9	25.5	38.2	80.3
Total	$ 134.0	$ 86.4	$ 371.1	$ 230.7
Operating costs and expenses:				
EPCO and affiliates	$ 119.9	$ 105.4	$ 338.2	$ 318.2
Energy Transfer Equity and subsidiaries	12.5	5.9	23.6	15.0
Cenac and affiliates	6.0	13.0	33.0	30.2
Unconsolidated affiliates	(4.8)	(11.5)	(15.4)	(37.4)
Total	$ 133.6	$ 112.8	$ 379.4	$ 326.0
General and administrative expenses:				
EPCO and affiliates	$ 24.9	$ 20.7	$ 74.9	$ 68.9
Cenac and affiliates	0.5	0.8	2.1	2.1
Total	$ 25.4	$ 21.5	$ 77.0	$ 71.0
Other expense:				
EPCO and affiliates	$ --	$ --	$ --	$ 0.3

The following table summarizes our related party receivable and payable amounts at the dates indicated:

	September 30, 2009	December 31, 2008
Accounts receivable - related parties:		
EPCO and affiliates	$ --	$ 0.2
Energy Transfer Equity and subsidiaries	6.4	35.0
Other	3.2	0.1
Total	$ 9.6	$ 35.3
Accounts payable - related parties:		
EPCO and affiliates	$ 12.0	$ 14.1
Energy Transfer Equity and subsidiaries	27.2	0.1
Other	5.0	3.2
Total	$ 44.2	$ 17.4

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Significant Relationships and Agreements with EPCO and affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not a part of our consolidated group of companies:

§ EPCO and its privately held affiliates;

§ EPGP, our general partner;

§ Enterprise GP Holdings, which owns and controls our general partner; and

§ the Employee Partnerships.

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with our own financial statements. Our transactions with Duncan Energy Partners are eliminated in consolidation. A description of our relationship with Duncan Energy Partners is presented within this Note 13.

EPCO is a privately held company controlled by Dan L. Duncan, who is also a director and Chairman of EPGP, our general partner. At September 30, 2009, EPCO and its affiliates beneficially owned 168,005,206 (or 35.2%) of our outstanding common units, which includes 13,952,402 of our common units owned by Enterprise GP Holdings. In addition, at September 30, 2009, EPCO and its affiliates beneficially owned 77.8% of the limited partner interests of Enterprise GP Holdings and 100% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of EPGP. The principal business activity of EPGP is to act as our managing partner. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO.

As our general partner, EPGP received cash distributions of $124.9 million and $106.4 million from us during the nine months ended September 30, 2009 and 2008, respectively. These amounts include incentive distributions of $109.9 million and $92.8 million for the nine months ended September 30, 2009 and 2008, respectively.

See Note 11 for information regarding the private placement of 5,940,594 common units with a privately held affiliate of EPCO in September 2009.

We and EPGP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its privately held subsidiaries depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its privately held affiliates received from us and Enterprise GP Holdings $354.9 million and $300.2 million in cash distributions during the nine months ended September 30, 2009 and 2008, respectively.

EPCO ASA. We have no employees. Substantially all of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA. We, Duncan Energy Partners, Enterprise GP Holdings and our respective general partners are among the parties to the ASA. Our operating costs and expenses include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of EPCO's employees to the extent that such employees spend time on our businesses. We reimbursed EPCO $138.9 million for operating costs and expenses and $24.9 million for general and administrative costs for the three months ended September 30, 2009. For the nine months ended September 30, 2009, we reimbursed EPCO $384.1 million for operating costs and expenses and $74.9 million for general and administrative costs.

Relationship with Energy Transfer Equity

In May 2007, Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner. As a result of common control of us and Enterprise GP Holdings, Energy Transfer Equity and its consolidated subsidiaries are related parties to our consolidated businesses.

We recorded $54.5 million and $99.6 million, respectively, of revenues from Energy Transfer Partners, L.P. ("ETP"), primarily from NGL marketing activities for the three months ended September 30, 2009 and 2008. For the nine months ended September 30, 2009 and 2008, we recorded $266.5 million and $413.0 million, respectively, of revenues from ETP, primarily from NGL marketing activities. We incurred $113.1 million and $56.5 million for the three months ended September 30, 2009 and 2008, respectively, in costs of sales and operating costs and expenses. For the nine months ended September 30, 2009 and 2008, we incurred $310.1 million and $134.4 million, respectively, in costs of sales and operating costs and expenses. We have a long-term revenue generating contract with Titan Energy Partners, L.P. ("Titan"), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract continues until March 31, 2010 and contains renewal and extension options. We and Energy Transfer Company ("ETC OLP") transport natural gas on each other's systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

Relationship with Duncan Energy Partners

Duncan Energy Partners was formed in September 2006 and did not acquire any assets prior to February 5, 2007, which was the date it completed its initial public offering and acquired controlling interests in five midstream energy businesses from EPO in a dropdown transaction (the "DEP I Midstream Businesses"). On December 8, 2008, through a second dropdown transaction, Duncan Energy Partners acquired controlling interests in three additional midstream energy businesses from EPO (the "DEP II Midstream Businesses"). The business purpose of Duncan Energy Partners is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates under common control. Duncan Energy Partners is engaged in (i) the gathering, transportation and storage of natural gas; (ii) NGL transportation and fractionation; (iii) the storage of NGL and petrochemical products; (iv) the transportation of petrochemical products; and (v) the marketing of NGLs and natural gas.

At September 30, 2009, Duncan Energy Partners was owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP Operating Partnership, L.P., a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business. At September 30, 2009, EPO beneficially owned approximately 58% of Duncan Energy Partners' limited partner interests and 100% of its general partner.

Enterprise Products Partners has continued involvement with all of the subsidiaries of Duncan Energy Partners, including the following types of transactions: (i) it utilizes Duncan Energy Partners' storage services to support its Mont Belvieu fractionation and other businesses; (ii) it buys from, and sells to, Duncan Energy Partners natural gas in connection with its normal business activities; and (iii) it is currently the sole shipper on an NGL pipeline system located in South Texas that is owned by Duncan Energy Partners.

Duncan Energy Partners issued an aggregate 8,943,400 of its common units in June and July 2009, which generated net proceeds of approximately $137.4 million. Duncan Energy Partners used the net proceeds from its issuance of these units to repurchase and cancel an equal number of its common units beneficially owned by EPO. The repurchase of Duncan Energy Partners' common units beneficially owned by EPO was reviewed and approved by the ACG Committees of EPGP and DEP GP.

Omnibus Agreement. Under the Omnibus Agreement, EPO agreed to make additional contributions to Duncan Energy Partners as reimbursement for Duncan Energy Partners' 66% share of any excess construction costs above the (i) $28.6 million of estimated capital expenditures to complete Phase II expansions of the DEP South Texas NGL Pipeline System and (ii) $14.1 million of estimated construction costs for additional brine production capacity and above-ground storage reservoir projects at Mont Belvieu, Texas. Both projects were underway at the time of Duncan Energy Partners' initial public offering. EPO made cash contributions to Duncan Energy Partners of $1.4 million and $32.5 million in connection with the Omnibus Agreement during the nine months ended September 30, 2009 and 2008, respectively. The majority of these contributions related to funding the Phase II expansion costs of the DEP South Texas NGL Pipeline System. EPO will not receive an increased allocation of earnings or cash flows as a result of these contributions to South Texas NGL and Mont Belvieu Caverns.

Mont Belvieu Caverns' LLC Agreement. EPO made cash contributions of $14.1 million and $86.4 million under the Mont Belvieu Caverns limited liability company agreement during the nine months ended September 30, 2009 and 2008, respectively, to fund 100% of certain storage-related projects for the benefit of EPO's NGL marketing activities. At present, Mont Belvieu Caverns is not expected to generate any identifiable incremental cash flows in connection with these projects; thus, the sharing ratio for Mont Belvieu Caverns is not expected to change from the current sharing ratio of 66% for Duncan Energy Partners and 34% for EPO. EPO expects to make additional contributions of approximately $9.1 million to fund such projects during the fourth quarter of 2009. The constructed assets will be the property of Mont Belvieu Caverns.

Company and Limited Partnership Agreements – DEP II Midstream Businesses. Enterprise Holdings III, LLC ("Enterprise III") has not yet participated in expansion project spending with respect to the DEP II Midstream Businesses, although it may elect to invest in existing or future expansion projects at a later date. As a result, Enterprise GTM Holdings L.P. has funded 100% of such growth capital spending and its Distribution Base has increased from $473.4 million at December 31, 2008 to $745.7 million at September 30, 2009. The Enterprise III Distribution Base was unchanged at $730.0 million at September 30, 2009.

Relationships with Unconsolidated Affiliates

Our significant related party revenue and expense transactions with unconsolidated affiliates consist of the sale of natural gas to Evangeline and Promix. In addition, we purchase NGL storage, transportation and fractionation services from Promix. For additional information regarding our unconsolidated affiliates, see Note 7.

Relationship with Cenac

In connection with our marine services acquisition in February 2008, Cenac and affiliates became a related party of ours due to their ownership of TEPPCO units through October 26, 2009, which converted to our common units, and other considerations. We entered into a transitional operating agreement with Cenac in which our fleet of tow boats and tank barges (acquired from Cenac) continued to be operated by employees of Cenac for a period of up to two years following the acquisition. Under this agreement, we paid Cenac a monthly operating fee and reimbursed Cenac for personnel salaries and related employee benefit expenses, certain repairs and maintenance expenses and insurance premiums on the equipment. Effective August 1, 2009, the transitional operating agreement was terminated. Personnel providing services pursuant to the agreement became employees of EPCO and will continue to provide services under the ASA. Concurrently with the termination of the transitional operating agreement, we entered into a two-year consulting agreement with Mr. Cenac and Cenac Marine Services, L.L.C. under which Mr. Cenac has agreed to supervise the day-to-day operations of our marine services business on a part-time basis and, at our request, provide related management and transitional services.

Note 14. Earnings Per Unit

The following table presents the net income available to EPGP for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income attributable to Enterprise Products Partners L.P.	$ 212.9	$ 203.1	$ 624.8	$ 726.0
Less incentive earnings allocations to EPGP	(38.1)	(32.0)	(109.9)	(92.8)
Net income available after incentive earnings allocation	174.8	171.1	514.9	633.2
Multiplied by EPGP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to EPGP	$ 3.5	$ 3.4	$ 10.3	$ 12.7
Incentive earnings allocation to EPGP	$ 38.1	$ 32.0	$ 109.9	$ 92.8
Standard earnings allocation to EPGP	3.5	3.4	10.3	12.7
Net income available to EPGP	41.6	35.4	120.2	105.5
Adjustment for ASC 260 (1)	2.5	1.1	5.3	3.2
Net income available to EPGP for EPU purposes	$ 44.1	$ 36.5	$ 125.5	$ 108.7

(1) For purposes of computing basic and diluted earnings per unit, the master limited partnerships subsections of ASC 260 have been applied.

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated and does not include any pro forma impact relating to outstanding TEPPCO units:

	For the Three Month Ended September 30,		For the Nine Month Ended September 30,	
	2009	2008	2009	2008
BASIC EARNINGS PER UNIT				
Numerator				
Net income attributable to Enterprise Products Partners L.P.	$ 212.9	$ 203.1	$ 624.8	$ 726.0
Net income available to EPGP for EPU purposes	(44.1)	(36.5)	(125.5)	(108.7)
Net income available to limited partners	$ 168.8	$ 166.6	$ 499.3	$ 617.3
Denominator				
Weighted – average common units	461.5	435.3	456.0	434.6
Weighted – average time-vested restricted units	2.8	2.3	2.4	2.0
Total	464.3	437.6	458.4	436.6
Basic earnings per unit				
Net income per unit before EPGP earnings allocation	$ 0.45	$ 0.46	$ 1.36	$ 1.66
Net income available to EPGP	(0.09)	(0.08)	(0.27)	(0.25)
Net income available to limited partners	$ 0.36	$ 0.38	$ 1.09	$ 1.41
DILUTED EARNINGS PER UNIT				
Numerator				
Net income attributable to Enterprise Products Partners L.P.	$ 212.9	$ 203.1	$ 624.8	$ 726.0
Net income available to EPGP for EPU purposes	(44.1)	(36.5)	(125.5)	(108.7)
Net income available to limited partners	$ 168.8	$ 166.6	$ 499.3	$ 617.3
Denominator				
Weighted – average common units	461.5	435.3	456.0	434.6
Weighted – average time-vested restricted units	2.8	2.3	2.4	2.0
Incremental option units	0.1	0.2	0.1	0.3
Total	464.4	437.8	458.5	436.9
Diluted earnings per unit				
Net income per unit before EPGP earnings allocation	$ 0.45	$ 0.46	$ 1.36	$ 1.66
Net income available to EPGP	(0.09)	(0.08)	(0.27)	(0.25)
Net income available to limited partners	$ 0.36	$ 0.38	$ 1.09	$ 1.41

Note 15. Commitments and Contingencies

Litigation

On occasion, we or our unconsolidated affiliates are named as a defendant in litigation and legal proceedings, including regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We are unaware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our financial position, results of operations or cash flows.

We evaluate our ongoing litigation based upon a combination of litigation and settlement alternatives. These reviews are updated as the facts and combinations of the cases develop or change. Assessing and predicting the outcome of these matters involves substantial uncertainties. In the event that the assumptions we used to evaluate these matters change in future periods or new information becomes available, we may be required to record a liability for an adverse outcome. In an effort to mitigate potential adverse consequences of litigation, we could also seek to settle legal proceedings brought against us. We have not recorded any significant reserves for any litigation in our supplemental financial statements.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of the State of Delaware (the “Delaware Court”), in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and us or our affiliates. Mr. Brinckerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants (i) TEPPCO, certain of its current and former directors, and certain of its affiliates, (ii) us and certain of our affiliates, (iii) EPCO and (iv) Dan L. Duncan.

The amended complaint alleges, among other things, that the defendants caused TEPPCO to enter into specified transactions that were unfair to TEPPCO or otherwise unfairly favored us or our affiliates over TEPPCO. These transactions are alleged to include: (i) the joint venture to further expand the Jonah system entered into by TEPPCO and us in August 2006 (the plaintiff alleges that TEPPCO did not receive fair value for allowing us to participate in the joint venture); (ii) the sale by TEPPCO of its Pioneer natural gas processing plant and certain gas processing rights to us in March 2006 (the plaintiff alleges that the purchase price we paid did not provide fair value to TEPPCO); and (iii) certain amendments to TEPPCO’s partnership agreement, including a reduction in the maximum tier of TEPPCO’s incentive distribution rights in exchange for TEPPCO units. The amended complaint seeks (i) rescission of the amendments to TEPPCO’s partnership agreement, (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the amended complaint and (iii) an award to plaintiff of the costs of the action, including fees and expenses of his attorneys and experts. By its Opinion and Order dated November 25, 2008, the Delaware Court dismissed Mr. Brinckerhoff’s individual and putative class action claims with respect to the amendments to TEPPCO’s partnership agreement. We refer to this action and the remaining claims in this action as the “Derivative Action.”

On April 29, 2009, Peter Brinckerhoff and Renee Horowitz, as Attorney in Fact for Rae Kenrow, purported unitholders of TEPPCO, filed separate complaints in the Delaware Court as putative class actions on behalf of other unitholders of TEPPCO, concerning the TEPPCO Merger. On May 11, 2009, these actions were consolidated under the caption Texas Eastern Products Pipeline Company, LLC Merger Litigation, C.A. No. 4548-VCL (“Merger Action”). The complaints name as defendants us, EPGP, TEPPCO GP, the directors of TEPPCO GP, EPCO and Dan L. Duncan.

The Merger Action complaints allege, among other things, that the terms of the merger (as proposed as of the time the Merger Action complaints were filed) are grossly unfair to TEPPCO's unitholders and that the TEPPCO Merger is an attempt to extinguish the Derivative Action without consideration. The complaints further allege that the process through which the Special Committee of the ACG Committee of TEPPCO GP was appointed to consider the TEPPCO Merger is contrary to the spirit and intent of TEPPCO's partnership agreement and constitutes a breach of the implied covenant of fair dealing.

The complaints seek relief (i) enjoining the defendants and all persons acting in concert with them from pursuing the TEPPCO Merger, (ii) rescinding the TEPPCO Merger to the extent it is consummated, or awarding rescissory damages in respect thereof, (iii) directing the defendants to account for all damages suffered or to be suffered by the plaintiffs and the purported class as a result of the defendants' alleged wrongful conduct, and (iv) awarding plaintiffs' costs of the actions, including fees and expenses of their attorneys and experts.

On June 28, 2009, the parties entered into a Memorandum of Understanding pursuant to which we, TEPPCO, EPCO, TEPPCO GP, all other individual defendants and the plaintiffs have proposed to settle the Merger Action and the Derivative Action. The Memorandum of Understanding contemplated that the parties would enter into a stipulation of settlement within 30 days from the date of the Memorandum of Understanding. On August 5, 2009, the parties entered into a Stipulation and Agreement of Compromise, Settlement and Release (the "Settlement Agreement") contemplated by the Memorandum of Understanding. Pursuant to the Settlement Agreement, the board of directors of TEPPCO GP recommended to TEPPCO's unitholders that they approve the adoption of the merger agreement and took all necessary steps to seek unitholder approval for the merger as soon as practicable. Pursuant to the Settlement Agreement, approval of the merger required, in addition to votes required under TEPPCO's partnership agreement, that the actual votes cast in favor of the proposal by holders of TEPPCO's outstanding units, excluding those held by defendants to the Derivative Action, exceed the actual votes cast against the proposal by those holders. The Settlement Agreement further provides that the Derivative Action was considered by TEPPCO GP's Special Committee to be a significant TEPPCO benefit for which fair value was obtained in the merger consideration.

The Settlement Agreement is subject to customary conditions, including Delaware Court approval. A hearing regarding approval of the Settlement Agreement by the Delaware Court was held on October 12, 2009, but the Delaware Court has yet to rule on the settlement. There can be no assurance that the Delaware Court will approve the settlement in the Settlement Agreement. In such event, the proposed settlement as contemplated by the Settlement Agreement may be terminated. Among other things, the plaintiffs' agreement to settle the Derivative Action and Merger Action litigation, including their agreement to the fairness of the terms and process of the merger negotiations, is subject to (i) the drafting and execution of other such documentation as may be required to obtain final Delaware Court approval and dismissal of the actions, (ii) Delaware Court approval and the mailing of the notice of settlement which sets forth the terms of settlement to TEPPCO's unitholders, (iii) consummation of the TEPPCO Merger and (iv) final Delaware Court certification and approval of the settlement and dismissal of the actions. See Notes 1 and 19 for additional information regarding our relationship with TEPPCO, including information related to the TEPPCO Merger.

Additionally, on June 29 and 30, 2009, respectively, M. Lee Arnold and Sharon Olesky, purported unitholders of TEPPCO, filed separate complaints in the District Courts of Harris County, Texas, as putative class actions on behalf of other unitholders of TEPPCO, concerning the TEPPCO Merger (the "Texas Actions"). The complaints name as defendants us, TEPPCO, TEPPCO GP, EPGP, EPCO, Dan L. Duncan, Jerry Thompson, and the board of directors of TEPPCO GP. The allegations in the complaints are similar to the complaints filed in Delaware on April 29, 2009 and seek similar relief. The named plaintiffs in the two Texas Actions (the "Texas Plaintiffs/Objectors") have also appeared in the Delaware proceedings as objectors to the settlement of those cases which are awaiting court approval. On October 7, 2009, the Texas Plaintiffs/Objectors and the parties to the Settlement Agreement entered into a Stipulation to Withdraw Objection (the "Stipulation"). In accordance with the Stipulation, TEPPCO made certain supplemental disclosures and, if the Settlement Agreement obtains Final Court Approval (as defined in the Settlement Agreement), the Texas Plaintiffs/Objectors have agreed to dismiss the Texas Actions with prejudice and, pending such Final Court Approval, will take no action to prosecute the Texas Actions.

In February 2007, EPO received a letter from the Environment and Natural Resources Division of the U.S. Department of Justice related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third party, Magellan Ammonia Pipeline, L.P. (“Magellan”), and a previous release of ammonia on September 27, 2004 from the same pipeline. EPO was the operator of this pipeline until July 1, 2008. This matter was settled in September 2009, and Magellan has agreed to pay all assessed penalties.

The Attorney General of Colorado on behalf of the Colorado Department of Public Health and Environment filed suit against us and others on April 15, 2008 in connection with the construction of a pipeline near Parachute, Colorado. The State sought a temporary restraining order and an injunction to halt construction activities since it alleged that the defendants failed to install measures to minimize damage to the environment and to follow requirements for the pipeline’s stormwater permit and appropriate stormwater plan. We have entered into a settlement agreement with the State that dismisses the suit and assesses a fine of approximately $0.2 million.

In January 2009, the State of New Mexico filed suit in District Court in Santa Fe County, New Mexico, under the New Mexico Air Quality Control Act. The lawsuit arose out of a February 27, 2008 Notice Of Violation issued to Marathon Oil Corp. (“Marathon”) as operator of the Indian Basin natural gas processing facility located in Eddy County, New Mexico. We own a 42.4% undivided interest in the assets comprising the Indian Basin facility. The State alleges violations of its air laws, and Marathon is attempting to negotiate an acceptable resolution with the state. The State seeks penalties and remedial projects above $0.1 million. Marathon continues to work with the State to determine if resolution of the case is possible. We believe that any potential penalties will not have a material impact on our consolidated financial position, results of operations or cash flows.

In connection with our dissociation from TOPS (see Note 6), Oiltanking filed an original petition against Enterprise Offshore Port System, LLC, EPO, TEPPCO O/S Port System, LLC, TEPPCO and TEPPCO GP in the District Court of Harris County, Texas, 61st Judicial District (Cause No. 2009-31367), asserting, among other things, that the dissociation was wrongful and in breach of the TOPS partnership agreement, citing provisions of the agreement that, if applicable, would continue to obligate us and TEPPCO to make capital contributions to fund the project and impose liabilities on us and TEPPCO. On September 17, 2009, we and TEPPCO entered into a settlement agreement with certain affiliates of Oiltanking and TOPS that resolved all disputes between the parties related to the business and affairs of the TOPS project (including the litigation described above). We recognized approximately $66.9 million of expense during the third quarter of 2009 in connection with this settlement. This charge is classified within our Offshore Pipelines & Services business segment.

Regulatory Matters

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases” or “GHGs” and including carbon dioxide and methane, may be contributing to climate change. On April 17, 2009, the U.S. Environmental Protection Agency (“EPA”) issued a notice of its proposed finding and determination that emission of carbon dioxide, methane, and other GHGs present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere. The EPA’s finding and determination would allow it to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. Although it may take the EPA several years to adopt and impose regulations limiting emissions of GHGs, any such regulation could require us to incur costs to reduce emissions of GHGs associated with our operations. In addition, on June 26, 2009, the U.S. House of Representatives approved adoption of the “American Clean Energy and Security Act of 2009,” also known as the “Waxman-Markey cap-and-trade legislation” or “ACESA.” ACESA would establish an economy-wide cap on emissions of GHGs in the

United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. The U.S. Senate has also begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs, and may have an adverse effect on our business, financial position, demand for our operations, results of operations and cash flows.

Contractual Obligations

Scheduled maturities of long-term debt. See Notes 10 and 19 for information regarding changes in our consolidated debt obligations.

Operating lease obligations. During the second quarter of 2009, we entered into a 20-year right-of-way agreement with the Jicarilla Apache Nation in support of continued natural gas gathering activities on our San Juan gathering system in Northwest New Mexico. Pending approval of this agreement by the U.S. Department of the Interior, our minimum lease obligations will be $3.0 million for the first year and $2.0 million per year for each of the next succeeding four years. Aggregate minimum lease commitments are $43.3 million over the 20-year contractual term. The agreement also provides for contingent rentals that are calculated annually based on actual throughput volumes and then current natural gas and NGL prices. Our agreement with the Jicarilla Apache Nation does not provide for renewal options beyond the 20-year lease term.

Prior to May 2009, we leased rail and truck terminal facilities in Mont Belvieu, Texas from Martin. At December 31, 2008, our remaining aggregate minimum lease commitments under this agreement were $56.8 million through the contractual term ending in 2023. The lease agreement with Martin was terminated upon our acquisition of such facilities in May 2009. See Note 8 for additional information regarding our acquisition of certain rail and truck terminal facilities from Martin.

Except for the foregoing, there have been no material changes in our operating lease commitments since December 31, 2008. Lease and rental expense was $16.2 million and $13.2 million during the three months ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009 and 2008, lease and rental expense was $45.0 million and $42.7 million, respectively.

Purchase obligations. Apart from that discussed below, there have been no material changes in our consolidated purchase obligations since December 31, 2008.

As a result of our dissociation from TOPS, capital expenditure commitments decreased by an estimated $203.0 million from that reported in this Current Report on Form 8-K under Exhibit 99.2. See Note 6 for additional information regarding TOPS.

In January 2008, TEPPCO entered into an amended throughput and deficiency agreement with Colonial Pipeline Company ("Colonial") related to our Boligee river terminal. Under terms of the agreement, Colonial agreed to provide transportation services to the Boligee terminal for a period of 10-years effective January 1, 2009. The minimum annual throughput commitment to Colonial was approximately 8.0 million barrels of product. We agreed to pay annual deficiency charges if it failed to meet its minimum annual volume throughput commitment.

The contractual annual minimum commitment of 8.0 million barrels was premised upon expected throughput volumes at the Boligee terminal, which was designed to serve several planned river terminals to be constructed. In September 2009, the expansion river terminal construction projects were suspended. Based on the current level of terminal volumes, we forecast that the Boligee terminal will not be able to meet its annual minimum commitment to Colonial over the term of the contract. As a result, we accrued a liability of $28.7 million for deficiency fees that it reasonably estimates will be incurred due to the expected level of throughput volumes at Boligee. In accordance with applicable accounting standards, we will adjust its accrual if it determines that it is probable that the amount it is obligated to pay Colonial changes in the future.

At September 30, 2009, the accrued liability was recorded as a component of other current liabilities and other long-term liabilities, as appropriate, on our Unaudited Supplemental Condensed Consolidated Balance Sheets. The accrued deficiency charges are included in operating costs and expenses for the three and nine months ended September 30, 2009. There was no impact on net income attributable to Enterprise Products Partners, as all of this charge was absorbed by noncontrolling interests in consolidation (i.e., by former owners of TEPPCO).

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of September 30, 2009, claims against us totaled approximately $4.8 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters, if any, that might result from the resolution of such disputes have not been reflected in our supplemental consolidated financial statements.

Note 16. Significant Risks and Uncertainties

Insurance Matters

EPCO completed its annual insurance renewal process during the second quarter of 2009. In light of recent hurricane and other weather-related events, the renewal of policies for weather-related risks resulted in significant increases in premiums and certain deductibles, as well as changes in the scope of coverage.

EPCO's deductible for onshore physical damage from windstorms increased from $10.0 million per storm to $25.0 million per storm. EPCO's onshore program currently provides $150.0 million per occurrence for named windstorm events compared to $175.0 million per occurrence in the prior year. With respect to offshore assets, the windstorm deductible increased significantly from $10.0 million per storm (with a one-time aggregate deductible of $15.0 million) to $75.0 million per storm. EPCO's offshore program currently provides $100.0 million in the aggregate compared to $175.0 million in the aggregate for the prior year. For non-windstorm events, EPCO's deductible for both onshore and offshore physical damage remained at $5.0 million per occurrence. For certain of our major offshore assets, our producer customers have agreed to provide a specified level of physical damage insurance for named windstorms. For example, the producers associated with our Independence Hub and Marco Polo platforms have agreed to cover windstorm generated physical damage costs up to $250.0 million for each platform.

Business interruption coverage in connection with a windstorm event remains in place for onshore assets, but was eliminated for offshore assets. Onshore assets covered by business interruption insurance must be out-of-service in excess of 60 days before any losses from business interruption will be covered. Furthermore, pursuant to the current policy, we will now absorb 50% of the first $50.0 million of any loss in excess of deductible amounts for our onshore assets.

In the third quarter of 2008, certain of our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were damaged by Hurricanes Gustav and Ike. The disruptions in hydrocarbon production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which in turn caused a decrease in gross operating margin from these operations. As a result of our share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined cumulative total of $48.8 million of repair costs for property damage in connection with these two storms through September 30, 2009. We continue to file property damage claims in connection with the damage caused by these storms. We recognize business interruption proceeds as income when they are received in cash.

The following table summarizes proceeds we received during the periods indicated from business interruption and property damage insurance claims with respect to certain named storms:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Business interruption proceeds:				
Hurricane Katrina	$ --	$ --	$ --	$ 0.5
Hurricane Rita	--	--	--	0.7
Hurricane Ike	19.2	--	19.2	--
Total business interruption proceeds	19.2	--	19.2	1.2
Property damage proceeds:				
Hurricane Ivan	0.7	--	0.7	--
Hurricane Katrina	3.5	2.5	26.7	9.4
Hurricane Rita	--	--	--	2.7
Total property damage proceeds	4.2	2.5	27.4	12.1
Total	$ 23.4	$ 2.5	$ 46.6	$ 13.3

At September 30, 2009, we had $22.6 million of estimated property damage claims outstanding related to storms that we believe are probable of collection during the next twelve months and $45.2 million thereafter. To the extent we estimate the dollar value of such damages, please be aware that a change in our estimates may occur, if and when additional information becomes available.

Credit Risk due to Industry Concentrations

On January 6, 2009, LyondellBasell Industries and its affiliates ("LBI") announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. At the time of the bankruptcy filing, we had approximately $10.0 million of net credit exposure to LBI. We resolved our outstanding claims with LBI in October 2009 with no gain or loss being recorded in connection with the settlement. We continue to do business with this important customer; however, we continue to monitor our credit exposure to LBI. LBI accounted for 5.9% of our consolidated revenues during 2008.

Note 17. Supplemental Cash Flow Information

The following table provides information regarding the net effect of changes in our operating assets and liabilities for the periods indicated:

	For the Nine Months Ended September 30,	
	2009	2008
Decrease (increase) in:		
Accounts and notes receivable – trade	$ (551.2)	$ (242.0)
Accounts receivable – related parties	36.0	22.3
Inventories	(830.1)	(383.6)
Prepaid and other current assets	(6.4)	(59.0)
Other assets	(14.1)	18.6
Increase (decrease) in:		
Accounts payable – trade	(3.1)	(36.4)
Accounts payable – related parties	18.9	30.4
Accrued product payables	817.1	381.8
Accrued interest payable	(25.6)	(15.2)
Other accrued expenses	(11.0)	35.3
Other current liabilities	(26.7)	11.7
Other liabilities	21.3	(5.0)
Net effect of changes in operating accounts	$ (574.9)	$ (241.1)

We incurred liabilities for construction in progress that had not been paid at September 30, 2009 and December 31, 2008 of $122.2 million and $109.0 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Supplemental Condensed Statements of Consolidated Cash Flows.

Note 18. Supplemental Condensed Consolidated Financial Information of EPO

EPO conducts substantially all of our business. Currently, we have no independent operations or material assets outside those of EPO. EPO consolidates the financial statements of Duncan Energy Partners with its own financial statements.

Immediately after the closing of the TEPPCO Merger (see Note 19), Enterprise Products Partners L.P. contributed its ownership interests in TEPPCO and TEPPCO GP to EPO. The following supplemental condensed consolidated financial information for EPO has been recast to include TEPPCO and TEPPCO GP using the same basis of presentation described in Note 1 for our consolidated financial statements.

Enterprise Products Partners L.P. guarantees the debt obligations of EPO, with the exception of Duncan Energy Partners’ debt obligations. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation. See Note 10 for additional information regarding our consolidated debt obligations.

The reconciling items between our supplemental consolidated financial statements and those of EPO are insignificant.

The following table presents supplemental condensed consolidated balance sheet data for EPO at the dates indicated:

	September 30, 2009	December 31, 2009
ASSETS		
Current assets	$ 4,358.9	$ 3,114.6
Property, plant and equipment, net	17,297.0	16,732.8
Investments in unconsolidated affiliates	899.3	911.9
Intangible assets, net	1,093.2	1,182.9
Goodwill	2,018.3	2,019.6
Other assets	265.1	261.1
Total	$ 25,931.8	$ 24,222.9
LIABILITIES AND EQUITY		
Current liabilities	$ 3,840.3	$ 3,100.8
Long-term debt	11,999.2	11,637.9
Other long-term liabilities	220.9	176.5
Equity	9,871.4	9,307.7
Total	$ 25,931.8	$ 24,222.9
Total EPO debt obligations guaranteed Enterprise Products Partners L.P.	$ 8,682.2	$ 8,561.8

The following table presents supplemental condensed consolidated statements of operations data for EPO for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues	$ 6,789.4	$ 10,499.1	$ 17,110.6	$ 29,544.2
Costs and expenses	6,439.8	10,107.9	15,915.4	28,249.1
Equity in income of unconsolidated affiliates	15.0	10.0	32.0	31.8
Operating income	364.6	401.2	1,227.2	1,326.9
Other expense	(160.8)	(135.2)	(469.8)	(391.2)
Income before provision for income taxes	203.8	266.0	757.4	935.7
Provision for income taxes	(7.7)	(7.7)	(26.8)	(20.1)
Net income	196.1	258.3	730.6	915.6
Net (income) loss attributable to the noncontrolling interest	25.1	(55.0)	(91.2)	(188.2)
Net income attributable to EPO	$ 221.2	$ 203.3	$ 639.4	$ 727.4

Note 19. Subsequent Events

Issuance of Senior Notes Q and R

On October 5, 2009, EPO issued $500.0 million in principal amount of 10-year unsecured Senior Notes Q and $600.0 million in principal amount of 30-year unsecured Senior Notes R. Senior Notes Q were issued at 99.355% of their principal amount, have a fixed interest rate of 5.25% and mature on January 31, 2020. Senior Notes R were issued at 99.386% of their principal amount, have a fixed interest rate of 6.125% and mature on October 15, 2039. Net proceeds from the issuance of Senior Notes Q and R were used (i) to repay $500.0 million in aggregate principal amount of Senior Notes F that matured in October 2009, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general partnership purposes.

Senior Notes Q and R rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes Q and R are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Completion of TEPPCO Merger

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 of our common units for each TEPPCO unit. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. TEPPCO's units, which had been trading on the NYSE under the ticker symbol TPP, have been delisted and are no longer publicly traded.

A privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

Under the terms of the TEPPCO Merger agreements, Enterprise GP Holdings received 1,331,681 of our common units and an increase in the capital account of EPGP to maintain its 2% general partner interest in us as consideration for 100% of the membership interests of TEPPCO GP. Following the closing of the TEPPCO Merger, affiliates of EPCO owned approximately 31.3% of our outstanding limited partner units, including 3.4% owned by Enterprise GP Holdings.

The post-merger partnership, which retains the name Enterprise Products Partners L.P., accesses the largest producing basins of natural gas, NGLs and crude oil in the U.S., and serves some of the largest consuming regions for natural gas, NGLs, refined products, crude oil and petrochemicals. The post-merger partnership owns almost 48,000 miles of pipelines comprised of over 22,000 miles of NGL, refined product and petrochemical pipelines, over 20,000 miles of natural gas pipelines and more than 5,000 miles of crude oil pipelines. The merged partnership's logistical assets include approximately 200 MMBbls of NGL, refined product and crude oil storage capacity; 27 Bcf of natural gas storage capacity; one of the largest NGL import/export terminals in the U.S., located on the Houston Ship Channel; 60 NGL, refined product and chemical terminals spanning the U.S. from the west coast to the east coast; and crude oil import terminals on the Texas Gulf Coast. The post-merger partnership owns interests in 17 fractionation plants with over 600 thousand barrels per day ("MBPD") of net capacity; 25 natural gas processing plants with a net capacity of approximately 9 Bcf/d; and 3 butane isomerization facilities with a capacity of 116 MBPD. The post-merger partnership is also one of the largest inland tank barge companies in the U.S.

The merger transactions will be accounted for as a reorganization of entities under common control. The financial and operating activities of Enterprise Products Partners, TEPPCO and Enterprise GP Holdings and their respective general partners, and EPCO and its privately held subsidiaries, are under the common control of Dan L. Duncan.

We incurred $26.8 million of merger-related expenses during the nine months ended September 30, 2009 that are reflected as a component of general and administrative costs.

In connection with the TEPPCO Merger, EPO commenced offers in September 2009 to exchange all of TEPPCO's outstanding notes for a corresponding series of new EPO notes. The purpose of the exchange offer was to simplify our capital structure following the TEPPCO Merger. The exchanges were completed on October 27, 2009. The new EPO notes are guaranteed by Enterprise Products Partners L.P.

As presented in the following table, the aggregate principal amount of the TEPPCO notes was $2 billion, of which $1.95 billion was exchanged:

TEPPCO Notes Exchanged	Principal Amount Exchanged	Principal Amount Not Exchanged
7.625% Senior Notes due 2012	$ 490.5	$ 9.5
6.125% Senior Notes due 2013	182.5	17.5
5.90% Senior Notes due 2013	237.6	12.4
6.65% Senior Notes due 2018	349.7	0.3
7.55% Senior Notes due 2038	399.6	0.4
7.00% Junior Fixed/Floating Subordinated Notes due 2067	285.8	14.2
	$ 1,945.7	$ 54.3

The EPO notes issued in the exchange will be recorded at the same carrying value as the TEPPCO notes being replaced. Accordingly, we will recognize no gain or loss for accounting purposes related to this exchange. All note exchange direct costs paid to third parties will be expensed.

In addition to the debt exchange, we gained approval from the requisite TEPPCO noteholders to eliminate substantially all of the restrictive covenants and reporting requirements associated with the remaining TEPPCO notes.

Upon the consummation of the TEPPCO Merger, EPO repaid and terminated indebtedness under TEPPCO’s Revolving Credit Facility.

EXHIBIT 99.4

ENTERPRISE PRODUCTS PARTNERS L.P.
RECAST OF CERTAIN SECTIONS OF THE QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTERLY PERIOD ENDING SEPTEMBER 30, 2009

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Recast of Item 2.

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

For the three and nine months ended September 30, 2009 and 2008.

The following information should be read in conjunction with our unaudited supplemental condensed consolidated financial statements and accompanying notes included in this Current Report on Form 8-K under Exhibit 99.3. In addition, the following information and such unaudited condensed consolidated financial statements should also be read in conjunction with the audited financial statements and related notes, together with our discussion and analysis of financial position and results of operations included in this Current Report on Form 8-K under Exhibits 99.1 and 99.2.

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

Key References Used in this Report

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our," or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries, which now includes TEPPCO Partners, L.P. and its general partner.

References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts substantially all of its business.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO and a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "DEP." References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to "EPGP" mean Enterprise Products GP, LLC, which is our general partner.

References to "Enterprise GP Holdings" mean Enterprise GP Holdings L.P., a publicly traded limited partnership, the units of which are listed on the NYSE under the ticker symbol "EPE." Enterprise GP Holdings owns EPGP. References to "EPE Holdings" mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO) prior to their mergers with our subsidiaries. On October 26, 2009, we completed our merger with TEPPCO and TEPPCO GP (such related mergers referred to herein individually and together as the "TEPPCO Merger"). For additional information regarding the TEPPCO Merger, see "Recent Developments" included within this Item 2.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). Enterprise GP Holdings owns a noncontrolling interest in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to "EPCO" mean EPCO, Inc. and its wholly owned, privately held affiliates, which are related parties to all of the foregoing named entities.

We, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings, EPE Holdings, TEPPCO and TEPPCO GP are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

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
MBPD	= thousand barrels per day
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet
Bcf	= billion cubic feet

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A "Risk Factors" included under Exhibit 99.1 of this Current Report on Form 8-K. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. Except as required by 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.

Critical Accounting Policies and Estimates

A summary of the significant accounting policies we have adopted and followed in the preparation of our supplemental consolidated financial statements is included under Exhibit 99.1 of this Current Report on Form 8-K. Certain of these accounting policies require the use of estimates. As more fully described therein, the following estimates, in our opinion, are subjective in nature, require the exercise of judgment and involve complex analysis: depreciation methods and estimated useful lives of property, plant and equipment; measuring recoverability of long-lived assets and equity method investments; amortization methods and estimated useful lives of qualifying intangible assets; methods we employ to measure the fair value of goodwill; revenue recognition policies and use of estimates for revenues and expenses; reserves for environmental matters; and natural gas imbalances. These estimates are based on our current knowledge and understanding and may change as a result of actions we may take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial position, results of operations and cash flows.

Overview of Business

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs"), crude oil, refined products and certain petrochemicals. Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD."

In connection with the TEPPCO Merger, we revised our business segments. Our reorganized business segments reflect the manner in which these businesses are managed and reviewed by the chief executive officer of our general partner. Under our new business segment structure, we have five reportable business segments: NGL Pipelines & Services; Onshore Natural Gas Pipelines & Services; Onshore Crude Oil Pipelines & Services; Offshore Pipelines & Services; and Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We conduct substantially all of our business through EPO. We are owned 98% by our limited partners and 2% by our general partner, EPGP. EPGP is owned 100% by Enterprise GP Holdings.

Basis of Presentation

Since Enterprise Products Partners, TEPPCO and TEPPCO GP are under common control of Mr. Duncan, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. The inclusion of TEPPCO and TEPPCO GP in our supplemental consolidated financial statements was effective January 1, 2005 because an affiliate of EPCO under common control with Enterprise Products Partners originally acquired ownership interests in TEPPCO GP in February 2005.

Our consolidated financial statements prior to the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third party and related party ownership interests in TEPPCO and TEPPCO GP prior to the merger have been reflected as "Former owners of TEPPCO" a component of noncontrolling interest.

The financial statements of TEPPCO and TEPPCO GP were prepared from the separate accounting records maintained by TEPPCO and TEPPCO GP. All intercompany balances and transactions have been eliminated in consolidation.

As previously noted, the TEPPCO Merger was accounted for as a reorganization of entities under common control. The following information is provided to reconcile total revenues and total gross operating margin for the three and nine months ended September 30, 2009 and 2008, as currently presented with those we previously presented. There was no change in net income attributable to Enterprise Products Partners L.P. for such periods since net income attributable to TEPPCO and TEPPCO GP was allocated to noncontrolling interests. Additionally, there was no change in our reported earnings per unit for such periods. See “Other Items” included within this Item 2 for information regarding total segment gross operating margin, which is a non-generally accepted account principle (“non-GAAP”) financial measure of segment performance.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Total revenues, as previously reported	$ 4,596.1	$ 6,297.9	$ 11,527.1	$ 18,322.1
Revenues from TEPPCO	2,205.3	4,205.7	5,576.1	11,194.7
Revenues from Jonah Gas Gathering Company (“Jonah”) (1)	60.2	58.7	180.8	177.0
Eliminations (2)	(72.2)	(63.2)	(173.4)	(149.7)
Total revenues, as currently reported	$ 6,789.4	$ 10,499.1	$ 17,110.6	$ 29,544.1
Total segment gross operating margin, as previously reported	$ 560.9	$ 478.9	$ 1,618.8	$ 1,535.5
Gross operating margin from TEPPCO	62.5	122.9	309.9	379.7
Gross operating margin from Jonah	46.6	40.7	137.8	121.9
Eliminations (3)	(31.3)	(26.9)	(91.6)	(79.5)
Total segment gross operating margin, as currently reported	$ 638.7	$ 615.6	$ 1,974.9	$ 1,957.6

(1) Prior to the TEPPCO Merger, we and TEPPCO were joint venture partners in Jonah. As a result of the TEPPCO Merger, Jonah became a consolidated subsidiary.
(2) Represents the eliminations of revenues between us, TEPPCO and Jonah.
(3) Represents equity earnings from Jonah recorded by us and TEPPCO prior to the merger.

Recent Developments

The following information highlights our significant developments since January 1, 2009 through November 9, 2009 (the original filing date of our Quarterly Report on Form 10-Q for the nine months ended September 30, 2009).

Merger of TEPPCO and TEPPCO GP with Enterprise Products Partners

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPGO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 of our common units for each TEPPCO unit. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. TEPPCO’s units, which had been trading on the NYSE under the ticker symbol TPP, have been delisted and are no longer publicly traded.

A privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

Under the terms of the TEPPCO Merger agreements, Enterprise GP Holdings received 1,331,681 of our common units and an increase in the capital account of EPGP to maintain its 2% general partner interest in us as consideration for 100% of the membership interests of TEPPCO GP. Following the closing of the TEPPCO Merger, affiliates of EPCO owned approximately 31.3% of our outstanding limited partner units, including 3.4% owned by Enterprise GP Holdings.

The post-merger partnership, which retains the name Enterprise Products Partners L.P., accesses the largest producing basins of natural gas, NGLs and crude oil in the U.S., and serves some of the largest consuming regions for natural gas, NGLs, refined products, crude oil and petrochemicals. The post-merger partnership owns almost 48,000 miles of pipelines comprised of over 22,000 miles of NGL, refined product and petrochemical pipelines, over 20,000 miles of natural gas pipelines and more than 5,000 miles of crude oil pipelines. The merged partnership's logistical assets include approximately 200 MMBbls of NGL, refined product and crude oil storage capacity; 27 Bcf of natural gas storage capacity; one of the largest NGL import/export terminals in the U.S., located on the Houston Ship Channel; 60 NGL, refined product and chemical terminals spanning the U.S. from the west coast to the east coast; and crude oil import terminals on the Texas Gulf Coast. The post-merger partnership owns interests in 17 fractionation plants with over 600 MBPD of net capacity; 25 natural gas processing plants with a net capacity of approximately 9 Bcf/d; and 3 butane isomerization facilities with a capacity of 116 MBPD. The post-merger partnership is also one of the largest inland tank barge companies in the U.S.

The merger transactions will be accounted for as a reorganization of entities under common control in a manner similar to a pooling of interests. The financial and operating activities of Enterprise Products Partners, TEPPCO and Enterprise GP Holdings and their respective general partners, and EPCO and its privately held subsidiaries, are under the common control of Dan L. Duncan. See Note 18 of the Notes to Unaudited Supplemental Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K for selected financial information, including selected unaudited pro forma data, related to the merger.

In connection with the TEPPCO Merger, EPO commenced offers in September 2009 to exchange all of TEPPCO's outstanding notes (a combined principal amount of $2 billion) for a corresponding series of new EPO notes. The purpose of the exchange offer was to simplify our capital structure following the TEPPCO Merger. The exchanges were completed on October 27, 2009. The new EPO notes are guaranteed by Enterprise Products Partners L.P. The EPO notes issued in the exchange will be recorded at the same carrying value as the TEPPCO notes being replaced. Accordingly, we will recognize no gain or loss for accounting purposes related to this exchange. All note exchange direct costs paid to third parties will be expensed. In addition to the debt exchange, we gained approval from the requisite TEPPCO noteholders to eliminate substantially all of the restrictive covenants and reporting requirements associated with the remaining TEPPCO notes. Upon the consummation of the TEPPCO Merger, EPO repaid and terminated indebtedness under TEPPCO's revolving credit facility.

Enterprise Products Partners and Duncan Energy Partners Announce Extension of Acadian Gas System into Haynesville Shale Play

In October 2009, we and our affiliate, Duncan Energy Partners, announced plans for our jointly owned Acadian Gas System to extend its Louisiana intrastate natural gas pipeline system into Northwest Louisiana to provide producers in the rapidly expanding Haynesville Shale resource basin with access to additional markets through connections with the Acadian Gas System in South Louisiana and nine major interstate natural gas pipelines ("Haynesville Extension"). The Haynesville Shale covers about 2 million acres in Northwest Louisiana, almost all of which is under lease. Production from the approximately 200 wells drilled to date is estimated at more than 1 Bcf/d. Over 400 locations are in various stages of drilling and completion with approximately 150 rigs now working in the region.

As currently designed, our Haynesville Extension pipeline project will have the capacity to transport up to 1.4 Bcf/d of natural gas from the Haynesville area through a 249-mile pipeline that will connect with our existing Acadian Gas System. Subject to additional long-term commitments received before pipe orders are placed, the capacity of the Haynesville Extension could be increased to 2.0 Bcf/d. The pipeline is expected to be in service in September 2011.

The Acadian Gas System serves major natural gas markets along the Mississippi River corridor between Baton Rouge and New Orleans and has the ability to make physical deliveries into the Henry Hub. The Haynesville Extension will also have interconnects with major interstate pipelines include Florida Gas, Texas Eastern, Transco, Sonat, Columbia Gulf, Trunkline, ANR, Tennessee Gas and Texas Gas. Together with the capacity of the existing Acadian Gas System, the extension project will provide approximately 5.5 Bcf/d of redelivery capacity into an estimated 12 Bcf/d of available downstream pipeline takeaway capacity. Initially, the project will connect to nine Haynesville Shale producer locations in DeSoto and Red River parishes.

Along with providing much needed natural gas takeaway capacity for growing Haynesville production, the new pipeline is expected to provide shippers the opportunity to benefit from more favorable pricing points and diverse service options and access to the South Louisiana marketplace. For producers, the more flexible contracting options associated with an intrastate pipeline environment would help facilitate a seamless transaction for the producer from the field to the end user.

Currently, Duncan Energy Partners owns a 66% equity interest in the entities that own the Acadian Gas System, with EPO owning the remaining 34% equity interests. Duncan Energy Partners and EPO are in discussions as to the funding of the Haynesville Extension project.

EPO Issues $1.1 Billion of Senior Notes

In October 2009, EPO issued $500.0 million in principal amount of 5.25% fixed-rate, unsecured senior notes due January 2020 ("Senior Notes Q") and $600.0 million in principal amount of 6.125% fixed-rate, unsecured senior notes due October 2039 ("Senior Notes R"). Net proceeds from this offering were used (i) to repay $500.0 million in aggregate principal amount of senior notes that matured in October 2009 ("Senior Notes F"), (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general partnership purposes. For additional information regarding these issuances of debt, see Note 19 of the Notes to Unaudited Supplemental Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K.

Enterprise Products Partners Issues $226.4 million of Common Units

In September 2009, we issued 8,337,500 common units (including an overallotment amount of 1,087,500 common units) in an underwritten public offering at a price of $28.00 per unit. We used the combined net offering proceeds of $226.4 million to reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Enterprise Products Partners to Provide Natural Gas Transportation and Processing Services for Major Eagle Ford Shale Producer

In September 2009, we announced that we had entered into a long-term agreement to provide natural gas transportation and processing services on dedicated acreage owned by one of the largest and most active producers in the developing Eagle Ford Shale natural gas play in South Texas. The agreement covers more than 150,000 acres in the heart of the Eagle Ford Shale natural gas play. Stretching from the Mexico border along the Gulf Coast to near Louisiana, the Eagle Ford Shale production area covers more than 10 million acres in Texas and lies beneath or near our existing natural gas and NGL asset infrastructure in the region.

Enterprise Products Partners Enters into Agreement for $150.0 Million Private Placement of Common Units

On September 4, 2009, we agreed to issue 5,940,594 common units in a private placement to EPCO Holdings, Inc., a privately held affiliate controlled by Dan L. Duncan, for approximately $150.0 million, or $25.25 per unit. In accordance with the terms of the private placement, as approved by the Audit, Conflicts and Governance Committee of EPGP's Board of Directors on September 1, 2009, the per unit purchase price of $25.25 was calculated based on a five percent discount to the five-day volume weighted average price ("5-Day VWAP") of our common units, as reported by the NYSE at the close of business on September 4, 2009. The 5-Day VWAP was based on (i) the closing price for the common units on the NYSE for each of the trading days in such five-day period and (ii) the total trading volume for the common units reported by the NYSE for each such trading day. We used the net proceeds from this private placement to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for other general partnership purposes. The common units were issued on September 8, 2009.

Enterprise Products Partners Announces Expansion of NGL Fractionation Capacity at Mont Belvieu, Texas Complex

In August 2009, we announced plans to build a new 75 MBPD NGL fractionator at our Mont Belvieu, Texas complex that will provide us with additional capacity to handle growing NGL volumes from producing areas in the Rockies, the Barnett Shale and the emerging Eagle Ford Shale play in South Texas. This expansion, which is supported by long-term contracts, will be based on the design of our 75 MBPD Hobbs fractionator in Gaines County, Texas that began service in August 2007. When completed, the project will increase our NGL fractionation capacity at Mont Belvieu to approximately 300 MBPD and net system-wide capacity to approximately 600 MBPD. The project is expected to be completed in the first quarter of 2011.

Duncan Energy Partners' Equity Offering

In June 2009, Duncan Energy Partners completed an offering of 8,000,000 of its common units, which generated net proceeds of approximately $122.9 million. In July 2009, the underwriters to this offering exercised their option to purchase an additional 943,400 common units, which generated $14.5 million of additional net proceeds for Duncan Energy Partners. Duncan Energy Partners used the aggregate net proceeds from this offering to repurchase an equal number of its common units that were beneficially owned by EPO. Duncan Energy Partners subsequently cancelled the common units it repurchased from EPO.

Jicarilla Apache Nation and Enterprise Products Partners Announce Long-Term Right-of-Way Agreement

In June 2009, the Jicarilla Apache Nation and an affiliate of ours announced they had signed a 20-year right-of-way agreement that will allow us to continue our natural gas gathering operations on the Nation's reservation lands in Northwest New Mexico. Under the terms of the agreement, we will continue to own and operate existing infrastructure and related assets located on tribal land, including 545 miles of gathering lines connected to our San Juan Gathering system that have current throughput in excess of 30 MMcf/d of natural gas.

EPO Issues $500.0 Million of Senior Notes

In June 2009, EPO issued $500.0 million in principal amount of 4.60% fixed-rate, unsecured senior notes due August 2012 ("Senior Notes P"). Net proceeds from this offering were used (i) to repay the $200.0 Million Term Loan, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general partnership purposes. For additional information regarding this issuance of debt, see Note 10 of the Notes to Unaudited Supplemental Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K.

Acquisition of Marine Assets; Termination of Transitional Operating Agreement

In June 2009, TEPPCO acquired 19 tow boats and 28 tank barges from TransMontaigne Product Services Inc. ("TransMontaigne") for $50.0 million in cash. The acquired assets provide marine vessel fueling services (referred to as bunkering) for cruise liners and cargo ships and other ship-assist services and transport fuel oil for electric generation plants. The acquisition complements TEPPCO's existing fleet of marine vessels, which transport petroleum products along the nation's inland waterway system and in the Gulf of Mexico. In general, the newly acquired marine assets are supported by contracts that have a three to five year term and are based primarily in Miami, Florida, with additional assets located in Mobile, Alabama, and Houston, Texas. See Note 8 of the Notes to Unaudited Supplemental Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K for additional information regarding this business combination.

Effective August 1, 2009, personnel providing services to TEPPCO under a transitional operating agreement with Cenac Towing Co., L.L.C., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. (collectively, "Cenac") became employees of EPCO. The transitional operating agreement was then terminated. Concurrently with the termination, our marine services business entered into a two-year consulting agreement with Mr. Cenac and Cenac Marine Services, L.L.C. under which Mr. Cenac has agreed to supervise our marine services business' day-to-day operations on a part-time basis and, at our marine services business' request, provide related management and transitional services. The agreement entitles Mr. Cenac to $500,000 per year in fees, plus a one-time retainer of $200,000. The consulting agreement contains noncompetition and nonsolitation provisions similar to those contained in the transitional operating agreement, which apply until the expiration of the two-year period following the date of last service provided under the consulting agreement.

Enterprise Products Partners and TEPPCO Exit Texas Offshore Port System Partnership

In August 2008, our wholly owned subsidiaries together with Oiltanking Holding Americas, Inc. ("Oiltanking") formed the Texas Offshore Port System partnership ("TOPS"). Effective April 16, 2009, our wholly owned subsidiaries dissociated (exited) from TOPS. As a result, operating costs and expenses and net income for the nine months ended September 30, 2009 reflect a non-cash charge of $68.4 million. This loss represented the forfeiture of our cumulative investment in TOPS through the date of dissociation and reflected our capital contributions to TOPS for construction in progress amounts. On September 17, 2009, we entered into a settlement agreement with certain affiliates of Oiltanking that resolved all disputes between the parties related to the business and affairs of the TOPS project. We recognized approximately $66.9 million of expense during the third quarter of 2009 in connection with the payment of this cash settlement.

Service Begins on Shenzi Crude Oil Export Pipeline

In April 2009, we announced that construction of our crude oil pipeline serving the Shenzi field in the Gulf of Mexico had been completed and is now transporting production from the deepwater discovery. The 83-mile pipeline has a transportation capacity of 230 MBPD of crude oil and gives Shenzi producers access to the Cameron Highway Oil Pipeline and Poseidon Oil Pipeline systems, in which we have ownership interests and operate.

Service Begins on Sherman Extension Pipeline

In late February 2009, we and Duncan Energy Partners announced that construction had been completed on the 174-mile Sherman Extension expansion of our Texas Intrastate System, which extends through the heart of the prolific Barnett Shale natural gas play of North Texas. The completion of the Sherman Extension adds 1.1 Bcf/d of incremental natural gas takeaway capacity from the region, while providing producers in the Barnett Shale, and as far away as the Waha area of West Texas, with greater flexibility to reach the most attractive natural gas markets. The Texas Intrastate System is part of our Onshore Natural Gas Pipelines & Services business segment.

Initially, the Sherman Extension was in very limited service due to pipeline integrity issues on the connecting third party take-away pipeline, the Gulf Crossing Pipeline owned by Boardwalk Pipeline Partners, LP ("Boardwalk"). The Gulf Crossing Pipeline began ramping up its operations on August 1, 2009. As a result, the Sherman Extension started billing its demand charges at 95% of contracted volumes, which are 950 MMcf/d. Effective September 1, 2009, the Sherman Extension started billing demand charges at 100% of contracted volumes irrespective of actual transportation volumes. We are currently flowing approximately 700 MMcf/d. The demand charges are approximately $5.0 million a month.

Review of Consolidated Results

We have five reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Onshore Crude Oil Pipelines & Services, Offshore Pipelines & Services and Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold. For additional information regarding our business segments, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K.

Selected Price and Volumetric Data

The following table illustrates selected annual and quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods presented:

	Natural Gas, $/MMBtus (1)	NYMEX Crude Oil, $/barrel (2)	Ethane, $/gallon (1)	Propane, $/gallon (1)	Normal Butane, $/gallon (1)	Isobutane, $/gallon (1)	Natural Gasoline, $/gallon (1)	Polymer Grade Propylene, $/pound (1)	Refinery Grade Propylene, $/pound (1)
2008									
1st Quarter	$ 8.03	$ 97.82	$ 1.01	$ 1.47	$ 1.80	$ 1.87	$ 2.12	$ 0.61	$ 0.54
2nd Quarter	$ 10.94	$ 123.80	$ 1.05	$ 1.70	$ 2.05	$ 2.08	$ 2.64	$ 0.70	$ 0.67
3rd Quarter	$ 10.25	$ 118.22	$ 1.09	$ 1.68	$ 1.97	$ 1.99	$ 2.52	$ 0.78	$ 0.66
4th Quarter	$ 6.95	$ 59.08	$ 0.42	$ 0.80	$ 0.90	$ 0.96	$ 1.09	$ 0.37	$ 0.22
2008 Averages	$ 9.04	$ 99.73	$ 0.89	$ 1.41	$ 1.68	$ 1.72	$ 2.09	$ 0.62	$ 0.52
2009									
1st Quarter	$ 4.91	$ 43.31	$ 0.36	$ 0.68	$ 0.87	$ 0.97	$ 0.96	$ 0.26	$ 0.20
2nd Quarter	$ 3.51	$ 59.79	$ 0.43	$ 0.73	$ 0.93	$ 1.11	$ 1.21	$ 0.34	$ 0.28
3rd Quarter	$ 3.39	$ 68.24	$ 0.47	$ 0.87	$ 1.12	$ 1.19	$ 1.42	$ 0.48	$ 0.43
2009 Averages	$ 3.93	$ 57.11	$ 0.42	$ 0.76	$ 0.97	$ 1.09	$ 1.20	$ 0.36	$ 0.30

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including Oil Price Information Service (“OPIS”) and Chemical Market Associates, Inc. (“CMAI”). Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents a weighted-average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.

(2) Crude oil price is representative of an index price for West Texas Intermediate as measured on the New York Mercantile Exchange (“NYMEX”).

The following table presents our material average throughput, production and processing volumetric data. These statistics are reported on a net basis, taking into account our ownership interests in certain joint ventures and reflect the periods in which we owned an interest in such operations. Our operating statistics include volumes for newly constructed assets since the dates such assets were placed into service and for recently purchased assets since the date of acquisition.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	2,179	1,944	2,098	1,991
NGL fractionation volumes (MBPD)	467	424	456	436
Equity NGL production (MBPD)	116	109	116	108
Fee-based natural gas processing (MMcf/d)	2,247	2,064	2,685	2,469
Onshore Natural Gas Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	10,495	9,766	10,502	9,422
Onshore Crude Oil Pipelines & Services, net:				
Crude oil transportation volumes (MBPD)	654	618	683	690
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	1,374	1,244	1,458	1,449
Crude oil transportation volumes (MBPD)	369	147	278	190
Platform natural gas processing (MMcf/d)	694	583	741	588
Platform crude oil processing (MBPD)	17	14	10	19
Petrochemical & Refined Products Services, net:				
Butane isomerization volumes (MBPD)	104	71	98	85
Propylene fractionation volumes (MBPD)	67	58	67	59
Octane enhancement production volumes (MBPD)	13	8	9	9
Transportation volumes, primarily petrochemicals and refined products (MBPD)	762	761	797	815
Total transportation volumes, net:				
NGL, crude oil, petrochemical and refined products transportation volumes (MBPD)	3,964	3,470	3,856	3,686
Natural gas transportation volumes (BBtus/d)	11,869	11,010	11,960	10,871
Equivalent transportation volumes (MBPD) (1)	7,087	6,367	7,003	6,547

(1) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

Comparison of Consolidated Results of Operations

The following table summarizes key components of our consolidated income statement for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues	$ 6,789.4	$ 10,499.1	$ 17,110.6	$ 29,544.1
Operating costs and expenses	6,395.8	10,074.3	15,796.9	28,150.2
General and administrative costs	52.3	33.9	133.3	100.4
Equity in income of unconsolidated affiliates	15.0	10.1	32.0	31.8
Operating income	356.3	401.0	1,212.4	1,325.3
Interest expense	161.0	137.0	472.0	396.3
Provision for income taxes	7.7	7.7	26.8	20.1
Net income	187.8	258.1	715.8	914.1
Net income (loss) attributable to noncontrolling interest	(25.1)	55.0	91.0	188.1
Net income attributable to Enterprise Products Partners L.P.	212.9	203.1	624.8	726.0

Effective January 1, 2009, we adopted new accounting guidance that has been codified under ASC 810, which established accounting and reporting standards for noncontrolling interests, which were previously identified as minority interest in our financial statements. The new guidance requires, among other things, that (i) noncontrolling interests be presented as a component of equity on our consolidated balance sheet (i.e., elimination of the “mezzanine” presentation previously used for minority interest); (ii) minority interest amounts be eliminated as a deduction in deriving net income or loss and, as a result, that net income or loss be allocated between controlling and noncontrolling interests; and (iii) comprehensive income or loss to be allocated between controlling and noncontrolling interest. Earnings per unit amounts are not affected by these changes. See Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K for additional information regarding the establishment of the ASC by the Financial Accounting Standards Board ("FASB"). See Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K for additional information regarding noncontrolling interest.

The new presentation and disclosure requirements pertaining to noncontrolling interests have been applied retroactively to the consolidated financial information presented within Exhibits 99.3 and 99.4. As a result, net income reported for the three and nine months ended September 30, 2008 in these financial statements is higher than that disclosed previously; however, the allocation of such net income results in our unitholders, general partner and noncontrolling interests (i.e., the former minority interest) receiving the same amounts as they did previously.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

Our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners on a 100% basis. Volumetric data associated with the operations of Duncan Energy Partners are also included on a 100% basis in our consolidated statistical data.

Our gross operating margin by segment and in total is as follows for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Gross operating margin by segment:				
NGL Pipelines & Services	$ 403.4	$ 342.4	$ 1,118.1	$ 970.9
Onshore Natural Gas Pipelines & Services	108.4	133.0	391.5	452.8
Onshore Crude Oil Pipelines & Services	34.1	35.4	126.7	109.5
Offshore Pipelines & Services	22.8	16.4	83.0	133.3
Petrochemical & Refined Products Services	70.0	88.4	255.6	291.1
Total segment gross operating margin	$ 638.7	$ 615.6	$ 1,974.9	$ 1,957.6

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes, see "Other Items – Non-GAAP Reconciliations" included within this Item 2.

The following table summarizes the contribution to revenues from each business segment (including the effects of eliminations and adjustments) during the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
NGL Pipelines & Services:				
Sales of NGLs	$ 3,015.4	$ 4,212.6	$ 7,527.6	$ 12,433.2
Sales of other petroleum and related products	0.6	0.5	1.5	1.9
Midstream services	172.9	181.0	483.8	556.0
Total	3,188.9	4,394.1	8,012.9	12,991.1
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	585.8	859.2	1,645.4	2,400.4
Midstream services	182.5	182.0	535.3	550.6
Total	768.3	1,041.2	2,180.7	2,951.0
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	1,991.3	3,980.5	4,946.1	10,580.7
Midstream services	18.7	18.3	60.8	56.0
Total	2,010.0	3,998.8	5,006.9	10,636.7
Offshore Pipelines & Services:				
Sales of natural gas	0.3	0.9	0.9	2.5
Sales of crude oil	2.0	3.7	3.1	10.7
Midstream services	99.4	60.3	243.5	191.9
Total	101.7	64.9	247.5	205.1
Petrochemical and Refined Products Services:				
Sales of products	597.2	848.4	1,272.0	2,329.2
Midstream services	123.3	151.7	390.6	431.0
Total	720.5	1,000.1	1,662.6	2,760.2
Total consolidated revenues	$ 6,789.4	$ 10,499.1	$ 17,110.6	$ 29,544.1

Comparison of Three Months Ended September 30, 2009 with Three Months Ended September 30, 2008

Revenues for the third quarter of 2009 were $6.79 billion compared to $10.50 billion for the third quarter of 2008. The $3.71 billion quarter-to-quarter decrease in consolidated revenues is primarily due to lower energy commodity sales prices associated with our NGL, natural gas, crude oil and petrochemical marketing activities during the third quarter of 2009 compared to the third quarter of 2008. Consolidated revenues for the third quarter of 2009 include $19.2 million of cash proceeds from business interruption insurance due to the effects of Hurricane Ike on our operations.

Operating costs and expenses were $6.39 billion for the third quarter of 2009 versus $10.07 billion for the third quarter of 2008, a $3.68 billion quarter-to-quarter decrease. The cost of sales of our marketing activities decreased $3.46 billion quarter-to-quarter primarily due to lower energy commodity prices. Likewise, the operating costs and expenses of our natural gas processing plants decreased $316.1 million quarter-to-quarter primarily due to lower plant thermal reduction (i.e., PTR) costs attributable to the decline in energy commodity prices. Consolidated operating costs and expenses for the third quarter of 2009 include $66.9 million of expenses related to the settlement of litigation involving TOPS. General and administrative costs increased $18.4 million quarter-to-quarter primarily due to expenses we incurred during the third quarter of 2009 related to the TEPPCO Merger.

Changes in our revenues and costs and expenses quarter-to-quarter are primarily explained by fluctuations in energy commodity prices. The weighted-average indicative market price for NGLs was $0.88 per gallon during the third quarter of 2009 versus $1.68 per gallon during the third quarter of 2008 – a 48% decrease quarter-to-quarter. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in

Louisiana) decreased 67% quarter-to-quarter to an average of $3.39 per MMBtu during the third quarter of 2009 versus $10.25 per MMBtu during the third quarter of 2008. The market price of crude oil (as measured on the NYMEX) averaged $68.24 per barrel during the third quarter of 2009 compared to $118.22 per barrel during the third quarter of 2008. See "Results of Operations - Selected Price and Volumetric Data" within this Item 2 for additional historical energy commodity pricing information.

Equity in income from our unconsolidated affiliates was $15.0 million for the third quarter of 2009 compared to $10.1 million for the third quarter of 2008, a $4.9 million quarter-to-quarter increase. Collectively, equity in income from our investments in Cameron Highway Oil Pipeline Company ("Cameron Highway") and Poseidon Oil Pipeline, L.L.C. ("Poseidon") increased $8.7 million quarter-to-quarter due to higher transportation volumes during the third quarter of 2009 relative to the third quarter of 2008. Our investments in White River Hub, LLC ("White River Hub") and Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu") contributed equity in income of $0.9 million and $0.3 million, respectively, for the third quarter of 2009. The assets owned by White River Hub began commercial operations in December 2008. We acquired a 49% equity interest in Skelly-Belvieu during December 2008. Collectively, equity in income from our other equity investments decreased $5.0 million quarter-to-quarter primarily due to expiration of demand fee revenues in March 2009 at our Marco Polo platform and lower crude oil transportation volumes on the pipeline owned by Seaway Crude Pipeline Company ("Seaway"). The Marco Polo platform is owned through our investment in Deepwater Gateway, L.L.C. ("Deepwater Gateway").

Operating income for the third quarter of 2009 was $356.3 million compared to $401.0 million for the third quarter of 2008. Consolidated revenues and certain operating costs and expenses can fluctuate significantly due to changes in energy commodity prices without necessarily affecting our operating income to the same degree. Consequently, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $44.7 million quarter-to-quarter decrease in operating income.

Interest expense increased to $161.0 million for the third quarter of 2009 from $137.0 million for the third quarter of 2008. The $24.0 million quarter-to-quarter increase in interest expense is primarily due to our issuance of Senior Notes O in the fourth quarter of 2008, Senior Notes P in the second quarter of 2009 and a $10.2 million decrease in capitalized interest during the third quarter of 2009 relative to the third quarter of 2008. Average debt principal outstanding increased to $12.20 billion during the third quarter of 2009 from $10.63 billion during the third quarter of 2008 primarily due to debt incurred to fund growth capital projects.

As a result of items noted in the previous paragraphs, net income decreased $70.3 million quarter-to-quarter to $187.8 million for the third quarter of 2009 compared to $258.1 million for the third quarter of 2008. Net loss attributable to noncontrolling interests was $25.1 million for the third quarter of 2009 compared to net income attributable to noncontrolling interests of $55.0 million for the third quarter of 2008. Net loss attributable to noncontrolling interests for the third quarter of 2009 reflects a net loss of $42.1 million attributable to TEPPCO Partners, L.P. Likewise, net income attributable to noncontrolling interest for the third quarter of 2008 includes $47.1 million attributable to TEPPCO Partners, L.P. Net income attributable to Enterprise Products Partners increased $9.8 million quarter-to-quarter to $212.9 million for the third quarter of 2009 compared to $203.1 million for the third quarter of 2008.

In general, Hurricanes Gustav and Ike had an adverse effect on our operations in the Gulf of Mexico and onshore along the U.S. Gulf Coast during the third quarter of 2008. Storm-related disruptions in natural gas, NGL and crude oil production in these regions resulted in reduced volumes available to our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which in turn caused a decrease in gross operating margin for certain operations. In addition, property damage caused by these hurricanes resulted in lower revenues due to facility downtime as well as higher operating costs and expenses at certain of our plants and pipelines. As a result of insurance deductibles for windstorm damage, gross operating margin for the third quarter of 2008 includes $46.4 million of repair expenses for property damage sustained by our assets as a result of Hurricanes Gustav and Ike. Gross operating margin for the third quarter of 2009 includes $19.2 million of proceeds from business interruption insurance due to the effects of Hurricane Ike on our operations. For more information regarding our insurance program and claims related to these storms, see “Other Items – Insurance Matters” included within this Item 2.

The following information highlights significant quarter-to-quarter variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $403.4 million for the third quarter of 2009 compared to $342.4 million for the third quarter of 2008, a $61.0 million quarter-to-quarter increase. In general, this business segment benefited from a quarter-to-quarter increase in NGL transportation and fractionation volumes, improved results from our NGL marketing activities and lower fuel costs during the third quarter of 2009 compared to the third quarter of 2008. The third quarter of 2009 includes $1.2 million of cash proceeds from business interruption insurance claims. The following paragraphs provide a discussion of segment results excluding cash proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $238.0 million for the third quarter of 2009 compared to $237.6 million for the third quarter of 2008. Equity NGL production increased to 116 MBPD during the third quarter of 2009 from 109 MBPD during the third quarter of 2008. Gross operating margin from our NGL marketing activities increased $16.5 million quarter-to-quarter due to higher NGL sales margins and volumes during the third quarter of 2009 relative to the third quarter of 2008. Gross operating margin from our South Louisiana natural gas processing plants increased $8.1 million quarter-to-quarter. These facilities were negatively impacted by downtime and property damage repair expenses caused by Hurricanes Gustav and Ike during the third quarter of 2008. Collectively, gross operating margin from the remainder of our natural gas processing plants decreased $24.2 million quarter-to-quarter primarily due to lower processing margins in South Texas, the Permian Basin and Rocky Mountains.

Gross operating margin from our NGL pipelines and related storage business was $131.0 million for the third quarter of 2009 compared to $77.2 million for the third quarter of 2008, a $53.8 million quarter-to-quarter increase. Total NGL transportation volumes increased to 2,179 MBPD during the third quarter of 2009 from 1,944 MBPD during the third quarter of 2008. Gross operating margin from our Mid-America and Seminole pipeline systems increased $24.9 million quarter-to-quarter due to higher volumes and lower fuel costs. Collectively, gross operating margin from the remainder of our NGL pipelines, export dock and storage assets increased $28.9 million quarter-to-quarter largely due to increased storage volumes and fees at our Mont Belvieu storage complex, increased NGL export volumes, improved results from our assets in South Louisiana and lower fuel costs during the third quarter of 2009.

Gross operating margin from our NGL fractionation business was $33.2 million for the third quarter of 2009 compared to $27.6 million for the third quarter of 2008. Fractionation volumes increased to 467 MBPD during the third quarter of 2009 from 424 MBPD during the third quarter of 2008. The $5.6 million quarter-to-quarter increase in gross operating margin from this business is primarily due to increased fractionation volumes at our Mont Belvieu, Norco and Promix fractionators and lower fuel costs during the third quarter of 2009 relative to the third quarter of 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $108.4 million for the third quarter of 2009 compared to $133.0 million for the third quarter of 2008, a $24.6 million quarter-to-quarter decrease. Our onshore natural gas transportation volumes were 10,495 BBtus/d during the third quarter of 2009 compared to 9,766 BBtus/d during the third quarter of 2008.

Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $94.9 million for the third quarter of 2009 compared to $122.3 million for the third quarter of 2008, a $27.4 million quarter-to-quarter decrease. The Sherman Extension pipeline segment of our Texas Intrastate System began commercial operations on August 1, 2009 and contributed $9.0 million of gross operating margin during the third quarter of 2009, primarily from firm capacity fee revenues. Gross operating margin from our San Juan gathering system decreased $27.0 million quarter-to-quarter primarily due to lower commodity prices, which resulted in reduced revenues earned from natural gas gathering contracts where fees are indexed to regional natural gas prices and lower condensate sales revenues. Collectively, gross operating margin from the remainder of this business decreased $9.4 million quarter-to-quarter largely due to a decrease in natural gas transportation volumes and condensate sales revenues, both of which relate primarily to our Texas operations, during the third quarter of 2009 compared to the third quarter of 2008.

Gross operating margin from our natural gas storage business was $13.5 million for the third quarter of 2009 compared to $10.7 million for the third quarter of 2008. The $2.8 million quarter-to-quarter increase in gross operating margin is primarily due to increased storage activity at our Petal and Wilson natural gas storage facilities.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $34.1 million for the third quarter of 2009 compared to $35.4 million for the third quarter of 2008. Total onshore crude oil transportation volumes were 654 MBPD during the third quarter of 2009 compared to 618 MBPD during the third quarter of 2008. Gross operating margin decreased $1.3 million quarter-to-quarter primarily as a result of operational measurement gains recorded during the third quarter of 2008 compared to nominal operational measurement losses during the third quarter of 2009

Offshore Pipelines & Services. Gross operating margin from this business segment was $22.8 million for the third quarter of 2009 compared to $16.4 million for the third quarter of 2008. Results from this business segment for the third quarter of 2009 include $18.0 million of cash proceeds from business interruption insurance claims and $66.9 million of expenses for the TOPS litigation settlement. Results for the third quarter of 2008 were negatively impacted by downtime, reduced volumes and $35.5 million of property damage repair expenses resulting from Hurricanes Gustav and Ike. The following paragraphs provide a discussion of segment results excluding the effect of cash proceeds from business interruption insurance claims.

Gross operating margin from our offshore natural gas pipeline business was $8.7 million for the third quarter of 2009 compared to a loss of $22.8 million for the third quarter of 2008. The $31.5 million quarter-to-quarter increase in gross operating margin is primarily due to the impact of Hurricanes Gustav and Ike on this business during the third quarter of 2008, which includes $32.1 million of hurricane-related property damage repair expenses. Gross operating margin from our Independence Trail pipeline increased $6.3 million quarter-to-quarter due to higher transportation volumes. Collectively, gross operating margin from our other offshore natural gas pipelines decreased $6.9 million quarter-to-quarter primarily due to higher maintenance and repair expenses during the third quarter of 2009 associated with our Anaconda and HIOS pipeline systems. Offshore natural gas transportation volumes were 1,374 BBtus/d during the third quarter of 2009 compared to 1,244 BBtus/d during the third quarter of 2008.

Gross operating margin from our offshore crude oil pipeline business was a loss of $39.1 million for the third quarter of 2009 compared to earnings of $4.6 million for the third quarter of 2008, a $43.7 million quarter-to-quarter decrease. Excluding the $66.9 million of expenses we recorded during the third quarter of 2009 as a result of the TOPS litigation settlement, gross operating margin from this business increased $23.2 million quarter-to-quarter primarily due to the start-up of our Shenzi crude oil pipeline and higher transportation volumes on Cameron Highway and Poseidon crude oil pipelines, which were both impacted by last year’s hurricanes. We completed the Shenzi crude oil pipeline and began commercial operation during April 2009. Offshore crude oil transportation volumes were 369 MBPD during the third quarter of 2009 versus 147 MBPD during the third quarter of 2008.

We completed the Shenzi crude oil pipeline and began commercial operation during April 2009. Collectively, gross operating margin from our crude oil pipelines increased $23.2 million quarter-to-quarter primarily due to the start-up of our Shenzi crude oil pipeline and higher transportation volumes on Cameron Highway and Poseidon crude oil pipelines, which were both impacted by last year’s hurricanes. Offshore crude oil transportation volumes were 369 MBPD during the third quarter of 2009 versus 147 MBPD during the third quarter of 2008.

Gross operating margin from our offshore platform services business was $35.2 million for the third quarter of 2009 compared to $34.6 million for the third quarter of 2008, a $0.6 million quarter-to-quarter increase. Gross operating margin from our Independence Hub platform increased $3.1 million quarter-to-quarter due to higher natural gas processing volumes during the third quarter of 2009 relative to the third quarter of 2008. Collectively, gross operating margin from our other offshore platforms decreased $2.5 million quarter-to-quarter primarily due to the expiration of demand fee revenues at our Marco Polo platform in March 2009. Our net platform natural gas processing volumes increased to 694 MMcf/d during the third quarter of 2009 from 583 MMcf/d during the third quarter of 2008. Our net platform crude oil processing volumes increased to 17 MBPD during the third quarter of 2009 compared to 14 MBPD during the third quarter of 2008.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $70.0 million for the third quarter of 2009 compared to $88.4 million for the third quarter of 2008.

Gross operating margin from propylene fractionation and related activities was $23.2 million for the third quarter of 2009 compared to $31.3 million for the third quarter of 2008. The $8.1 million quarter-to-quarter decrease in gross operating margin is due to lower propylene sales margins, which more than offset the benefit of increased propylene fractionation volumes. Propylene fractionation volumes increased to 67 MBPD during the third quarter of 2009 from 58 MBPD during the third quarter of 2008.

Gross operating margin from butane isomerization was $22.5 million for the third quarter of 2009 compared to $19.1 million for the third quarter of 2008. The $3.4 million quarter-to-quarter increase in gross operating margin from this business is attributable to increased isomerization volumes, partially offset by lower by-product revenues. Butane isomerization volumes increased to 104 MBPD during the third quarter of 2009 from 71 MBPD during the third quarter of 2008.

Gross operating margin from octane enhancement was $5.3 million for the third quarter of 2009 compared to a loss of $12.9 million for the third quarter of 2008. The $18.2 million quarter-to-quarter increase in gross operating margin is due to higher volumes and lower operating expenses in the third quarter of 2009 compared to the third quarter of 2008. During the third quarter of 2008, in addition to downtime associated with Hurricane Ike, the octane enhancement facility had operational issues that resulted in higher operating expenses, downtime and decreased production volumes. Octane enhancement production volumes increased to 13 MBPD during the third quarter of 2009 from 8 MBPD during the third quarter of 2008.

Gross operating margin from refined products pipelines and related activities was $2.4 million for the third quarter of 2009 compared to $31.2 million for the third quarter of 2008, a $28.8 million quarter-to-quarter decrease. Gross operating margin for the third quarter of 2009 includes $28.7 million of expenses to accrue a liability for pipeline transportation deficiency fees owed to a third party. See Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K for information related to the liability for pipeline transportation deficiency fees. Transportation volumes on our refined products pipelines were 630 MBPD during the third quarter of 2009 compared to 661 MBPD during the third quarter of 2008.

Gross operating margin from marine transportation and other services was $16.6 million for the third quarter of 2009 compared to $19.7 million for the third quarter of 2008, a $3.1 million quarter-to-quarter decrease. Gross operating margin from marine transportation decreased $1.6 million quarter-to-quarter primarily due to higher operating expenses. The utilization of our fleet of marine vessels averaged 88% during the third quarter of 2009 versus 92% during the third quarter of 2008. Gross operating margin from the distribution of lubrication oils and specialty chemicals decreased $1.5 million quarter-to-quarter primarily due to lower margins from the sale of specialty chemicals during the third quarter of 2009 relative to the third quarter of 2008.

Comparison of Nine Months Ended September 30, 2009 with
Nine Months Ended September 30, 2008

Revenues for the first nine months of 2009 were $17.11 billion compared to $29.54 billion for the first nine months of 2008. The $12.43 billion period-to-period decrease in consolidated revenues is primarily due to lower energy commodity sales prices associated with our NGL, natural gas, crude oil and petrochemical marketing activities during the first nine months of 2009 compared to the first nine months of 2008.

Operating costs and expenses were $15.80 billion for the first nine months of 2009 compared to $28.15 billion for the first nine months of 2008, a $12.35 billion period-to-period decrease. The cost of sales of our marketing activities decreased $11.46 billion period-to-period primarily due to lower energy commodity prices. Likewise, the operating costs and expenses of our natural gas processing plants decreased $981.9 million period-to-period primarily due to lower PTR costs attributable to the decline in energy commodity prices. Consolidated operating costs and expenses for the first nine months of 2009 include $66.9 million of expenses related to the settlement of litigation involving TOPS and $68.4 million of expenses related to the forfeiture of our interest in TOPS. General and administrative costs increased $32.9 million period-to-period primarily due to expenses we incurred during the first nine months of 2009 in connection with the TEPPCO Merger.

Changes in our revenues and costs and expenses period-to-period are primarily explained by fluctuations in energy commodity prices. The weighted-average indicative market price for NGLs was $0.77 per gallon during the first nine months of 2009 versus $1.62 per gallon during the first nine months of 2008. The Henry Hub market price of natural gas decreased 60% period-to-period to an average of $3.93 per MMBtu during the first nine months of 2009 versus $9.74 per MMBtu during the first nine months of 2008. The NYMEX market price of crude oil averaged $57.11 per barrel during the first nine months of 2009 compared to $113.28 per barrel during the first nine months of 2008.

Equity in income from our unconsolidated affiliates was $32.0 million for the first nine months of 2009 compared to $31.8 million for the first nine months of 2008. Equity in income from our investment in Poseidon increased $5.0 million period-to-period due to higher transportation volumes during the first nine months of 2009 relative to the first nine months of 2008. Our investments in White River Hub and Skelly-Belvieu contributed equity in income of $2.9 million and $1.4 million, respectively, for the first nine months of 2009. Equity in income decreased $11.9 million period-to-period from our Marco Polo platform due to the expiration of demand fee revenues during March 2009. Collectively, equity in income of unconsolidated affiliates from our other equity investments increased $2.8 million period-to-period.

Operating income for the first nine months of 2009 was $1.21 billion compared to $1.33 billion for the first nine months of 2008. Consolidated revenues and certain operating costs and expenses can fluctuate significantly due to changes in energy commodity prices without necessarily affecting our operating income to the same degree. Consequently, the aforementioned changes in revenues, costs and expenses and equity in income of unconsolidated affiliates contributed to the $112.9 million period-to-period decrease in operating income.

Interest expense increased to $472.0 million for the first nine months of 2009 from $396.3 million for the first nine months of 2008. The $75.7 million period-to-period increase in interest expense is primarily due to our issuance of Senior Notes M and N in the second quarter of 2008, Senior Notes O in the fourth quarter of 2008 and a $27.8 million decrease in capitalized interest during the first nine months of 2009 relative to the first nine months of 2008. Average debt principal outstanding increased to $11.99 billion during the first nine months of 2009 from $9.83 billion during the first nine months of 2008 primarily due to debt incurred to fund growth capital investments. Provision for income taxes increased $6.7 million period-to-period primarily due to a one-time charge of $6.6 million associated with taxable gains arising from Dixie Pipeline Company's ("Dixie") sale of certain assets during the first nine months of 2009.

As a result of items noted in the previous paragraphs, net income decreased $198.3 million period-to-period to $715.8 million for the first nine months of 2009 compared to $914.1 million for the first nine months of 2008. Net income attributable to noncontrolling interests was $91.0 million for the first nine months of 2009 compared to $188.1 million for the first nine months of 2008. Such amounts reflect $48.5 million and $158.8 million of net income for the first nine months of 2009 and 2008, respectively, attributable to TEPPCO Partners, L.P. Net income attributable to Enterprise Products Partners decreased $101.2 million period-to-period to $624.8 million for the first nine months of 2009 compared to $726.0 million for the first nine months of 2008.

The following information highlights significant period-to-period variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $1.12 billion for the first nine months of 2009 compared to $970.9 million for the first nine months of 2008, a $147.2 million period-to-period increase. In general, this business segment benefited from a period-to-period increase in gross operating margin from our recently constructed Rocky Mountain natural gas processing plants and related hedging program, improved results from our NGL marketing activities and lower fuel costs during the first nine months of 2009 compared to the first nine months of 2008. The first nine months of 2009 include $1.2 million of proceeds from business interruption insurance claims compared to $1.1 million of proceeds during the first nine months of 2008. The following paragraphs provide a discussion of segment results excluding the effect of cash proceeds from business interruption insurance.

Gross operating margin from our natural gas processing and related NGL marketing business was $652.0 million for the first nine months of 2009 compared to $611.8 million for the first nine months of 2008. Equity NGL production increased to 116 MBPD during the first nine months of 2009 from 108 MBPD during the first nine months of 2008. The $40.2 million period-to-period increase in gross operating margin from this business is attributable to our Rocky Mountain natural gas processing facilities and related hedging program and our NGL marketing activities, which benefited from higher sales margins and increased equity NGL production.

Gross operating margin from our NGL pipelines and related storage business was $363.8 million for the first nine months of 2009 compared to $275.6 million for the first nine months of 2008, an $88.2 million period-to-period increase. Total NGL transportation volumes increased to 2,098 MBPD during the first nine months of 2009 from 1,991 MBPD during the first nine months of 2008. Gross operating margin from our Mid-America and Seminole Pipeline Systems increased $33.6 million period-to-period due to increased volumes and lower fuel costs. Gross operating margin from our Mont Belvieu storage complex increased $13.4 million period-to-period primarily due to higher volumes and fees. Collectively, gross operating margin from the remainder of our NGL pipelines, export dock and related storage assets increased $41.2 million period-to-period largely due to lower fuel costs, higher NGL export volumes and higher volumes and fees at certain of our South Louisiana assets during the first nine months of 2009 relative to the first nine months of 2008.

Gross operating margin from our NGL fractionation business was $101.1 million for the first nine months of 2009 compared to $82.4 million for the first nine months of 2008. Fractionation volumes increased to 456 MBPD during the first nine months of 2009 from 436 MBPD during the first nine months of 2008. Gross operating margin from this business increased $18.7 million period-to-period largely due to higher NGL fractionation volumes at our Mont Belvieu and Baton Rouge fractionators and lower fuel costs during the first nine months of 2009 relative to the first nine months of 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $391.5 million for the first nine months of 2009 compared to $452.8 million for the first nine months of 2008, a $61.3 million period-to-period decrease. Our onshore natural gas transportation volumes were 10,502 BBtus/d during the first nine months of 2009 compared to 9,422 BBtus/d during the first nine months of 2008.

Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $352.6 million for the first nine months of 2009 compared to $423.8 million for the first nine months of 2008, a $71.2 million period-to-period decrease. Gross operating margin from our Jonah gathering system increased $15.9 million period-to-period due to increased gathering volumes and lower fuel costs. The Sherman Extension pipeline segment of our Texas Intrastate System began commercial operations on August 1, 2009 and contributed $9.0 million of gross operating margin during 2009, primarily from firm capacity fee revenues. Gross operating margin from our San Juan gathering system decreased $89.2 million period-to-period due to lower fees indexed to regional natural gas prices and condensate sales revenues as a result of the period-to-period decrease in commodity prices. Lower natural gas gathering volumes in the Permian Basin resulted in a $9.2 million period-to-period decrease in gross operating margin on our Carlsbad gathering system. Collectively, gross operating margin from the remainder of the businesses classified within this segment increased $2.3 million period-to-period.

Gross operating margin from our natural gas storage business was $38.9 million for the first nine months of 2009 compared to $29.0 million for the first nine months of 2008. The $9.9 million period-to-period increase in gross operating margin is primarily due to increased storage activity at our Petal and Wilson natural gas storage facilities.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $126.7 million for the first nine months of 2009 compared to $109.5 million for the first nine months of 2008. Total onshore crude oil transportation volumes were 683 MBPD during the first nine months of 2009 compared to 690 MBPD during the first nine months of 2008. The $17.2 million period-to-period increase in segment gross operating margin is primarily due to increased crude oil sales margins during the first nine months of 2009 relative to the first nine months of 2008.

Offshore Pipelines & Services. Gross operating margin from this business segment was $83.0 million for the first nine months of 2009 compared to $133.3 million for the first nine months of 2008, a $50.3 million period-to-period decrease. Results for the first nine months of 2009 include $18.0 million of cash proceeds from business interruption insurance claims and $135.3 million of total expenses related to TOPS. Results for the first nine months of 2008 include $0.2 million of proceeds from business interruption insurance claims and $35.5 million of property damage repair expenses resulting from Hurricanes Gustav and Ike. Combined gross operating margin from our Independence Hub platform and Trail pipeline increased $55.1 million period-to-period reflecting downtime and repair expenses incurred during the first nine months of 2008. The following paragraphs provide a discussion of segment results excluding cash proceeds from business interruption insurance.

Gross operating margin from our offshore natural gas pipeline business was $43.1 million for the first nine months of 2009 compared to a loss of $8.3 million for the first nine months of 2008, a $51.4 million period-to-period increase. Offshore natural gas transportation volumes were 1,458 BBtus/d during the first nine months of 2009 versus 1,449 BBtus/d during the first nine months of 2008. Gross operating margin from our Independence Trail pipeline increased $37.4 million period-to-period. Collectively, gross operating margin from our other offshore natural gas pipelines increased $14.0 million period-to-period primarily due to hurricane-related property damage repair expenses recorded during the first nine months of 2008.

Gross operating margin from our offshore crude oil pipeline business was a loss of $88.0 million for the first nine months of 2009 compared to earnings of $31.6 million for the first nine months of 2008, a $119.6 million period-to-period decrease. Results for the first nine months of 2009 include $135.3 million of expenses related to TOPS. Gross operating margin from our offshore crude oil pipelines increased $15.7 million period-to-period primarily due to the start-up of our Shenzi crude oil pipeline and higher transportation volumes on our Poseidon crude oil pipeline. Total offshore crude oil transportation volumes were 278 MBPD during the first nine months of 2009 versus 190 MBPD during the first nine months of 2008.

Gross operating margin from our offshore platform services business was $109.9 million for the first nine months of 2009 compared to $109.8 million for the first nine months of 2008. Gross operating margin from our Independence Hub platform increased $17.7 million period-to-period. Collectively, gross operating margin from our other offshore platforms and related assets decreased $17.6 million period-to-period primarily due to lower natural gas and crude oil processing volumes at our Marco Polo platform as a result of continuing hurricane-related disruptions and the expiration of demand fee revenues at our Marco Polo and Falcon platforms. Our net platform natural gas processing volumes increased to 741 MMcf/d during the first nine months of 2009 compared to 588 MMcf/d during the first nine months of 2008. Our net platform crude oil processing volumes decreased to 10 MBPD during the first nine months of 2009 compared to 19 MBPD during the first nine months of 2008.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $255.6 million for the first nine months of 2009 compared to $291.1 million for the first nine months of 2008.

Gross operating margin from propylene fractionation and related activities was $68.8 million for the first nine months of 2009 compared to $66.2 million for the first nine months of 2008. The $2.6 million period-to-period increase in gross operating margin is largely due to higher propylene sales volumes during the first nine months of 2009 relative to the first nine months of 2008. Propylene fractionation volumes increased to 67 MBPD during the first nine months of 2009 from 59 MBPD during the first nine months of 2008.

Gross operating margin from butane isomerization was $56.5 million for the first nine months of 2009 compared to $77.9 million for the first nine months of 2008. The $21.4 million period-to-period decrease in gross operating margin from this business is primarily due to lower proceeds from the sale of plant by-products as a result of lower commodity prices. Butane isomerization volumes increased to 98 MBPD during the first nine months of 2009 from 85 MBPD during the first nine months of 2008.

Gross operating margin from octane enhancement was $4.1 million for the first nine months of 2009 compared to a loss of $5.7 million for the first nine months of 2008. The $9.8 million period-to-period increase in gross operating margin is due to lower operating expenses during the first nine months of 2009 compared to the first nine months of 2008. During the third quarter of 2008, in addition to downtime associated with Hurricane Ike, the octane enhancement facility had operational issues that resulted in higher operating expenses, downtime and decreased production volumes.

Gross operating margin from refined products pipelines and related activities was $78.2 million for the first nine months of 2009 compared to $103.3 million for the first nine months of 2008, a $25.1 million period-to-period decrease. Gross operating margin for the first nine months of 2009 includes $28.7 million of expenses to accrue a liability for pipeline transportation deficiency fees owed to a third party. Gross operating margin from the remainder of this business increased $3.6 primarily due lower operating expenses on our Products Pipeline System. Transportation volumes on our refined products pipelines were 674 MBPD during the first nine months of 2009 compared to 699 MBPD during the first nine months of 2008.

Gross operating margin from marine transportation and other services was $48.0 million for the first nine months of 2009 compared to $49.4 million for the first nine months of 2008. Gross operating margin from marine transportation increased $0.6 million period-to-period. The utilization of our fleet of marine vessels averaged 88% during the first nine months of 2009 versus 92% during the same period in 2008. Gross operating margin from the distribution of lubrication oils and specialty chemicals decreased $2.0 million period-to-period primarily due to lower margins from the sale of specialty chemicals and higher operating expense during the first nine months of 2009 compared to the first nine months of 2008.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and revolving credit arrangements. Capital expenditures for long-term needs resulting from business expansion projects and acquisitions are expected to be funded by a variety of sources (either separately or in combination) including operating cash flows, borrowings under credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interests in assets to affiliates or third parties. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At September 30, 2009, we had $77.3 million of unrestricted cash on hand and approximately $1.36 billion of available credit under our revolving credit facilities, which includes the available borrowing capacity of our consolidated subsidiaries such as Duncan Energy Partners. We had approximately $11.94 billion in principal outstanding under consolidated debt agreements at September 30, 2009. In total, our consolidated liquidity at September 30, 2009 was approximately $1.44 billion.

Registration Statements

We have a universal shelf registration statement on file with the SEC that allows us to issue an unlimited amount of debt and equity securities for general partnership purposes. In January 2009, we issued 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit under this registration statement. We used the net proceeds of $225.6 million from the January 2009 equity offering to temporarily reduce borrowings outstanding under EPO’s Multi-Year Revolving Credit Facility and for general partnership purposes. In June 2009, EPO issued $500.0 million in principal amount of Senior Notes P under this registration statement. Net proceeds from this senior note offering were used to repay the $200.0 Million Term Loan, to temporarily reduce borrowings outstanding under EPO’s Multi-Year Revolving Credit Facility and for general partnership purposes.

In September 2009, we issued 8,337,500 common units (including an over-allotment of 1,087,500 common units) to the public at an offering price of $28.00 per unit under this registration statement. We used the net proceeds of $226.4 million from the September 2009 equity offering to temporarily reduce borrowings outstanding under EPO’s Multi-Year Revolving Credit Facility and for general partnership purposes. In October 2009, EPO issued $1.1 billion in principal amount of Senior Notes Q and R under this registration statement. Net proceeds from this senior note offering were used to repay $500.0 million in aggregate principal amount of Senior Notes F that matured in October 2009, to temporarily reduce borrowings outstanding under EPO’s Multi-Year Revolving Credit Facility and for general partnership purposes.

We also have a registration statement on file with the SEC authorizing the issuance of up to 40,000,000 common units in connection with our distribution reinvestment plan (“DRIP”). During the nine months ended September 30, 2009, we issued 10,731,084 common units in connection with our DRIP, which generated proceeds of $254.7 million from plan participants. Affiliates of EPCO reinvested $226.5 million in connection with the DRIP during the nine months ended September 30, 2009.

In addition, we have a registration statement on file related to our employee unit purchase plan (“EUPP”), under which we can issue up to 1,200,000 common units. During the nine months ended September 30, 2009, we issued 141,512 common units to employees under this plan, which generated proceeds of $3.5 million.

Duncan Energy Partners has a universal shelf registration statement filed with the SEC that allows it to issue up to $1 billion of debt and equity securities. In June 2009, Duncan Energy Partners completed an offering of 8,000,000 of its common units, which generated net proceeds of approximately $122.9 million. In July 2009, the underwriters to this offering exercised their option to purchase an additional 943,400 common units, which generated approximately $14.5 million of additional net proceeds for Duncan Energy Partners. Duncan Energy Partners used the aggregate net proceeds from this offering to repurchase an equal number of its common units that were beneficially owned by EPO. Duncan Energy Partners subsequently cancelled the common units it repurchased from EPO. At September 30, 2009, Duncan Energy Partners can issue approximately $856.4 million of additional securities under its registration statement.

For information regarding our public debt obligations or partnership equity, see Notes
10 and 11, respectively, of the Notes to Unaudited Supplemental Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report of Form 8-K.

Letter of Credit Facilities

At September 30, 2009, EPO had outstanding a $50.0 million letter of credit relating to its commodity derivative instruments and a $58.3 million letter of credit related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's credit facilities. In addition, Duncan Energy Partners had an outstanding letter of credit in the amount of $1.0 million at September 30, 2009, which reduces the amount available for borrowing under its credit facility.

Credit Ratings of EPO

EPO's senior notes are rated investment-grade. Moody's Investor Services has assigned a rating of Baa3 and Standard & Poor's and Fitch Ratings have each assigned a rating of BBB-. Such ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any security. 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.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (dollars in millions). For information regarding the individual components of our cash flow amounts, see the Unaudited Condensed Statements of Consolidated Cash Flows included under Exhibit 99.3 of this Current Report on Form 8-K.

	For the Nine Months Ended September 30,	
	2009	**2008**
Net cash flows provided by operating activities	$ 891.7	$ 1,251.1
Cash used in investing activities	1,072.2	2,364.5
Cash provided by financing activities	196.5	1,130.7

The following information highlights the significant period-to-period variances in our cash flow amounts:

Comparison of Nine Months Ended September 30, 2009
with Nine Months Ended September 30, 2008

Operating Activities. Net cash flows provided by operating activities were $891.7 million for the nine months ended September 30, 2009 compared to $1.25 billion for the nine months ended September 30, 2008. This $359.4 million decrease in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding cash payments for interest and distributions received from unconsolidated affiliates) decreased $397.7 million period-to-period. Although our gross operating margin increased period-to-period (see "Results of Operations" within this Item 2), the reduction in operating cash flow is generally due to the timing of related cash receipts and disbursements and an increase cash outlays for in forward sales inventory. As a result of energy market conditions, we significantly increased our physical inventory purchases and related forward physical sales commitments during 2009. In general, the significant increase in volumes dedicated to forward physical sales contracts improves the overall utilization and profitability of our fee-based assets.

- § Cash payments for interest increased $33.6 million period-to-period primarily due to increased borrowings to finance our capital spending program and for general partnership purposes.

- § Distributions received from unconsolidated affiliates increased $4.7 million period-to-period primarily due to higher distributions received from Cameron Highway and Seaway, partially offset by lower distributions received from Deepwater Gateway.

Investing Activities. Cash used in investing activities was $1.07 billion for the nine months ended September 30, 2009 compared to $2.36 billion for the nine months ended September 30, 2008. This $1.29 billion decrease in cash used in investing activities was primarily due to the following:

- § Capital spending for property, plant and equipment, net of contributions in aid of construction costs, decreased $734.6 million period-to-period. For additional information related to our capital spending program, see "Capital Spending" included within this Item 2.

- § Restricted cash related to our hedging activities decreased $100.8 million (a cash inflow) during the nine months ended September 30, 2009 primarily due to the reduction of margin requirements related to derivative instruments we utilized. For the nine months ended September 30, 2008, restricted cash related to our hedging activities increased $112.2 million (a cash outflow).

- § Cash used for business combinations decreased $334.3 million period-to-period primarily due to reduced business combination activity in 2009. During the nine months ended September 30, 2009, we acquired rail and truck terminal facilities located in Mont Belvieu, Texas in May 2009 for $23.7 million and tow boats and tank barges primarily located in Miami, Florida in June 2009 for $50.0 million. During the nine months ended September 30, 2008, our combinations primarily involved marine assets in February 2008 for a total of $345.6 million and additional interests in Dixie in August 2008 for $57.0 million.

Financing Activities. Cash provided by financing activities was $196.5 million for the nine months ended September 30, 2009 compared to $1.13 billion for the nine months ended September 30, 2008. The $934.2 million decrease in cash provided by financing activities was primarily due to the following:

- § Net borrowings under our consolidated debt agreements were $369.8 million during the nine months ended September 30, 2009 compared to $1.94 billion during the nine months ended September 30, 2008. The $1.57 billion decrease in net borrowings was primarily attributable to lower amounts of senior notes issued period-to-period. During the nine months ended September 30, 2008, EPO and TEPPCO issued $2.1 billion in senior notes, compared to $500.0 million in senior notes during the nine months ended September 30, 2009.

- § Cash distributions to our partners increased $89.8 million period-to-period due to increases in our common units outstanding and quarterly distribution rates.

- § Cash distributions to the noncontrolling interest increased $48.5 million period-to-period primarily due to increases in the units outstanding and quarterly cash distribution rates to limited partners of Duncan Energy Partners and former owners of TEPPCO.

- § Net proceeds from the issuance of common units increased $878.2 million period-to-period primarily due to (i) the January and September 2009 issuances of common units that generated net proceeds of $452.0 million, (ii) the September 2009 private placement of common units that generated net proceeds of $150.0 million and (iii) an increase of $206.9 million in proceeds generated by our DRIP and EUPP period-to-period. Affiliates of EPCO reinvested $226.5 million of their distributions through the DRIP during the nine months ended September 30, 2009.

- § Contributions from noncontrolling interests were $140.9 million for the nine months ended September 30, 2009 compared to $271.3 million for the nine months ended September 30, 2008. This $130.4 million decrease is primarily attributable to the net proceeds that Duncan Energy Partners received from the issuance of an aggregate 8,943,400 of its common units in June and July 2009 compared to net proceeds of $271.3 million received from unit offerings to former owners of TEPPCO during the nine months ended September 30, 2008.

Capital Spending

The following table summarizes our capital spending by activity for the periods indicated (dollars in millions):

	For the Nine Months Ended September 30,	
	2009	**2008**
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 1,087.6	$ 1,822.2
Capital spending for business combinations	74.5	408.8
Capital spending for intangible assets	1.4	5.4
Capital spending for investments in unconsolidated affiliates	13.9	23.9
Total capital spending	$ 1,177.4	$ 2,260.3

Based on information currently available, we estimate our consolidated capital spending for the fourth quarter of 2009 will approximate $700.0 million, which includes estimated expenditures of $630.0 million for growth capital projects and acquisitions and $70.0 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our current announced strategic operating and growth plans. Our strategic operating and growth plans are dependent upon our ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements, issuance of equity, and potential divestitures of certain assets to third and/or related parties. Our forecast of capital expenditures may change due to factors beyond our control, such as weather-related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast may change as a result of decisions made by management at a later date, which may include acquisitions or decisions to take on additional partners.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor that determines how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs, and although we currently intend to make the forecasted expenditures discussed above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At September 30, 2009, we had approximately $497.0 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These remaining commitments primarily relate to construction of our Barnett Shale and Piceance Basin natural gas pipeline projects and the construction of a new NGL fractionator in Mont Belvieu, Texas.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Pipeline and Hazardous Materials Safety Administration, and participating state agencies. These federal and state agencies have issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain areas (such as high consequence areas as defined by the regulations) and to perform any necessary repairs.

The following table summarizes our accrued pipeline integrity costs for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Expensed	$ 11.7	$ 16.1	$ 33.4	$ 42.6
Capitalized	11.4	19.8	26.6	52.1
Total	$ 23.1	$ 35.9	$ 60.0	$ 94.7

We expect our cash outlays for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $39.4 million for the remainder of 2009.

Other Items

Contractual Obligations

For information regarding year-to-date changes in our contractual obligations, please see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K.

Off-Balance Sheet Arrangements

There have been no significant changes with regards to our off-balance sheet arrangements since those presented under Exhibit 99.2 of this Current Report on Form 8-K.

Summary of Related Party Transactions

On October 26, 2009, the TEPPCO Merger was completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became our wholly owned subsidiaries. For additional information regarding this material related party transaction, see "Recent Developments – Merger of TEPPCO and TEPPCO GP with Enterprise Products Partners" within this Item 2. The following table summarizes other related party transactions for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues from consolidated operations:				
Energy Transfer Equity and subsidiaries	$ 54.5	$ 99.6	$ 266.5	$ 413.0
Unconsolidated affiliates	55.9	153.4	155.7	318.7
Total	$ 110.4	$ 253.0	$ 422.2	$ 731.7
Cost of sales:				
EPCO and affiliates	$ 19.5	$ 10.3	$ 46.4	$ 31.0
Energy Transfer Equity and subsidiaries	100.6	50.6	286.5	119.4
Unconsolidated affiliates	13.9	25.5	38.2	80.3
Total	$ 134.0	$ 86.4	$ 371.1	$ 230.7
Operating costs and expenses:				
EPCO and affiliates	$ 119.9	$ 105.4	$ 338.2	$ 318.2
Energy Transfer Equity and subsidiaries	12.5	5.9	23.6	15.0
Cenac and affiliates	6.0	13.0	33.0	30.2
Unconsolidated affiliates	(4.8)	(11.5)	(15.4)	(37.4)
Total	$ 133.6	$ 112.8	$ 379.4	$ 326.0
General and administrative expenses:				
EPCO and affiliates	$ 24.9	$ 20.7	$ 74.9	$ 68.9
Cenac and affiliates	0.5	0.8	2.1	2.1
Total	$ 25.4	$ 21.5	$ 77.0	$ 71.0
Other expense:				
EPCO and affiliates	$ --	$ --	$ --	$ 0.3

The following table summarizes our related party receivable and payable amounts at the dates indicated:

	September 30, 2009	December 31, 2008
Accounts receivable - related parties:		
EPCO and affiliates	$ --	$ 0.2
Energy Transfer Equity and subsidiaries	6.4	35.0
Other	3.2	0.1
Total	$ 9.6	$ 35.3
Accounts payable - related parties:		
EPCO and affiliates	$ 12.0	$ 14.1
Energy Transfer Equity and subsidiaries	27.2	0.1
Other	5.0	3.2
Total	$ 44.2	$ 17.4

For additional information regarding our related party transactions, see Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K.

Non-GAAP Reconciliations

The following table presents a reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Total segment gross operating margin	$ 638.7	$ 615.6	$ 1,974.9	$ 1,957.6
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(206.0)	(181.3)	(602.9)	(532.3)
Impairment charges included in operating costs and expenses	(24.0)	--	(26.3)	--
Operating lease expense paid by EPCO	(0.2)	(0.5)	(0.5)	(1.6)
Gain from asset sales and related transactions in operating costs and expenses	0.1	1.1	0.5	2.0
General and administrative costs	(52.3)	(33.9)	(133.3)	(100.4)
Operating income	356.3	401.0	1,212.4	1,325.3
Other expense, net	(160.8)	(135.2)	(469.8)	(391.1)
Income before provision for income taxes	$ 195.5	$ 265.8	$ 742.6	$ 934.2

Recent Accounting Developments

The accounting standard setting bodies have recently issued accounting guidance since those reported in this Current Report on Form 8-K under Exhibit 99.2 that will or may affect our future financial statements. The recently issued accounting guidance relates to:

§ The hierarchy of GAAP and the establishment of the ASC (codified under ASC 105, Generally Accepted Accounting Principles);

§ Estimating fair value when the volume and level of activity for the asset or liability have significantly decreased and identifying circumstances that indicate a transaction is not orderly (codified under ASC 820, Fair Value Measurement and Disclosures);

§ Measuring liabilities at fair value (codified under ASC 820);

- § Providing quarterly disclosures about fair value estimates for all financial instruments not measured on the balance sheet at fair value (codified under ASC 825, Financial Instruments);

- § The accounting for, and disclosure of, events that occur after the balance sheet date but before financial statements are issued or are available to be issued (codified under ASC 855, Subsequent Events); and

- § Consolidation of variable interest entities (codified under ASC 810).

For additional information regarding recent accounting developments, see Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K.

Insurance Matters

EPCO completed its annual insurance renewal process during the second quarter of 2009. In light of recent hurricane and other weather-related events, the renewal of policies for weather-related risks resulted in significant increases in premiums and certain deductibles, as well as changes in the scope of coverage.

EPCO's deductible for onshore physical damage from windstorms increased from $10.0 million per storm to $25.0 million per storm. EPCO's onshore program currently provides $150.0 million per occurrence for named windstorm events compared to $175.0 million per occurrence in the prior year. With respect to offshore assets, the windstorm deductible increased significantly from $10.0 million per storm (with a one-time aggregate deductible of $15.0 million) to $75.0 million per storm. EPCO's offshore program currently provides $100.0 million in the aggregate compared to $175.0 million in the aggregate for the prior year. For non-windstorm events, EPCO's deductible for both onshore and offshore physical damage remained at $5.0 million per occurrence. For certain of our major offshore assets, our producer customers have agreed to provide a specified level of physical damage insurance for named windstorms. For example, the producers associated with our Independence Hub and Marco Polo platforms have agreed to cover windstorm generated physical damage costs up to $250.0 million for each platform.

Business interruption coverage in connection with a windstorm event remains in place for onshore assets, but was eliminated for offshore assets. Onshore assets covered by business interruption insurance must be out-of-service in excess of 60 days before any losses from business interruption will be covered. Furthermore, pursuant to the current policy, we will now absorb 50% of the first $50.0 million of any loss in excess of deductible amounts for our onshore assets.

For additional information regarding weather-related risks, including insurance matters in connection with Hurricanes Ivan, Katrina, Rita, Gustav and Ike, see Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K.

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

In the course of our normal business operations, we are exposed to certain risks, including changes in interest rates, commodity prices and, to a limited extent, foreign exchange rates. In order to manage risks associated with certain identifiable and anticipated transactions, we use derivative instruments. Derivatives are financial instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Typical derivative instruments include futures, forward contracts, swaps and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities. See Note 4 of the Notes to Unaudited Supplemental Condensed Consolidated Financial Statements included under Exhibit 99.3 of this Current Report on Form 8-K for additional information regarding our derivative instruments and hedging activities.

Our exposures to market risk have not changed materially since those reported under Item 7A "Quantitative and Qualitative Disclosures About Market Risk" under Exhibit 99.1 of this Current Report on Form 8-K.

Interest Rate Derivative Instruments

We utilize interest rate swaps, treasury locks and similar derivative instruments to manage our exposure to changes in the interest rates of certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following tables show the effect of hypothetical price movements on the estimated fair value ("FV") of interest rate swap portfolios at the dates presented (dollars in millions):

Enterprise Products Partners

Scenario	Resulting Classification	Swap Fair Value at September 30, 2009	Swap Fair Value at October 20, 2009
FV assuming no change in underlying interest rates	*Asset*	$ 46.5	$ 43.7
FV assuming 10% increase in underlying interest rates	*Asset*	40.4	37.7
FV assuming 10% decrease in underlying interest rates	*Asset*	52.7	49.6

Duncan Energy Partners

Scenario	Resulting Classification	Swap Fair Value at September 30, 2009	Swap Fair Value at October 20, 2009
FV assuming no change in underlying interest rates	*Liability*	$ (6.0)	$ (6.2)
FV assuming 10% increase in underlying interest rates	*Liability*	(5.8)	(6.0)
FV assuming 10% decrease in underlying interest rates	*Liability*	(6.2)	(6.4)

The following table shows the effect of hypothetical price movements on the estimated fair value of our forward starting swap portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Swap Fair Value at September 30, 2009	Swap Fair Value at October 20, 2009
FV assuming no change in underlying interest rates	*Asset*	$ 8.1	$ 10.4
FV assuming 10% increase in underlying interest rates	*Asset*	16.4	20.3
FV assuming 10% decrease in underlying interest rates	*Asset*	0.1	0.5

Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risk associated with such products, we enter into commodity derivative instruments such as forwards, basis swaps and futures contracts.

The following table shows the effect of hypothetical price movements on the estimated fair value of our natural gas marketing portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at September 30, 2009	Portfolio Fair Value at October 20, 2009
FV assuming no change in underlying commodity prices	*Liability*	$ (2.8)	$ (4.2)
FV assuming 10% increase in underlying commodity prices	*Liability*	(11.6)	(13.1)
FV assuming 10% decrease in underlying commodity prices	*Asset*	6.1	4.7

The following table shows the effect of hypothetical price movements on the estimated fair value of our NGL and petrochemical operations portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at September 30, 2009	Portfolio Fair Value at October 20, 2009
FV assuming no change in underlying commodity prices	*Liability*	$ (84.1)	$ (119.2)
FV assuming 10% increase in underlying commodity prices	*Liability*	(114.6)	(162.1)
FV assuming 10% decrease in underlying commodity prices	*Liability*	(53.6)	(76.3)

The following table shows the effect of hypothetical price movements on the estimated fair value of our crude oil marketing portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at September 30, 2009	Portfolio Fair Value at October 20, 2009
FV assuming no change in underlying commodity prices	*Asset*	$ 1.1	$ 0.5
FV assuming 10% increase in underlying commodity prices	*Asset*	1.3	0.6
FV assuming 10% decrease in underlying commodity prices	*Asset*	0.9	0.4

Foreign Currency Derivative Instruments

We are exposed to foreign currency exchange risk in connection with our NGL marketing activities in Canada. As a result, we could be adversely affected by fluctuations in currency rates between the U.S. dollar and Canadian dollar. In order to manage this risk, we may enter into foreign exchange purchase contracts to lock in the exchange rate.

In addition, we were exposed to foreign currency exchange risk in connection with a term loan denominated in Japanese yen. We entered into this loan agreement in November 2008 and the loan matured in March 2009. The derivative instrument used to hedge this risk was accounted for as a cash flow hedge and settled upon repayment of the loan.

At September 30, 2009, we had foreign currency derivative instruments with a notional amount of $5.5 million Canadian outstanding. The fair market value of this instrument was an asset of $0.3 million at September 30, 2009.

ENTERPRISE PRODUCTS PARTNERS L.P.
RECAST OF SELECTED FINANCIAL DATA FOR THE
THREE MONTHS ENDED MARCH 31, 2009 AND JUNE 30, 2009

Enterprise Products Partners L.P.
Supplemental Condensed Statements of Consolidated Operations – UNAUDITED
($ in millions, except per unit amounts)

	For the Three Months Ended March 31, 2009	For the Three Months Ended June 30, 2009
Revenues	$ 4,886.9	$ 5,434.3
Costs and expenses:		
Operating costs and expenses	4,376.6	5,024.5
General and administrative costs	34.9	46.1
Total costs and expenses	4,411.5	5,070.6
Equity in earnings of unconsolidated affiliates	7.4	9.6
Operating income	482.8	373.3
Other income (expense):		
Interest expense	(152.5)	(158.5)
Other, net	1.2	0.8
Total other expense	(151.3)	(157.7)
Income before provision for income taxes	331.5	215.6
Provision for income taxes	(16.0)	(3.1)
Net income	315.5	212.5
Net income attributable to noncontrolling interests	(90.2)	(25.9)
Net income attributable to Enterprise Products Partners L.P.	$ 225.3	$ 186.6
Net income allocated to:		
Limited partners	$ 186.3	$ 147.0
General partner	$ 39.0	$ 39.6
Per unit data (fully diluted): (1)		
Earnings per unit	$ 0.41	$ 0.32
Average LP units outstanding (in millions)	452.7	458.5

(1) For purposes of computing diluted earnings per unit, we used the provisions of Emerging Issues Task Force 07-4, Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships.

Enterprise Products Partners L.P.
Supplemental Condensed Operating Data – UNAUDITED
($ in millions)

	For the Three Months Ended March 31, 2009	For the Three Months Ended June 30, 2009
Gross operating margin by segment:		
NGL Pipelines & Services	$ 350.9	$ 363.8
Onshore Natural Gas Pipelines & Services	161.9	121.2
Onshore Crude Oil Pipelines & Services	50.5	42.1
Offshore Pipelines & Services	61.3	(1.1)
Petrochemical & Refined Products Services	89.5	96.1
Total gross operating margin	714.1	622.1
Adjustments to reconcile gross operating margin to operating income:		
Depreciation, amortization and accretion in operating costs and expenses	(196.4)	(200.5)
Impairment charges included in operating costs and expenses	--	(2.3)
Operating lease expense paid by EPCO in operating costs and expenses	(0.2)	(0.1)
Gain from asset sales and related transactions in operating costs and expenses	0.2	0.2
General and administrative costs	(34.9)	(46.1)
Operating income	$ 482.8	$ 373.3
Selected operating data: (1)		
NGL Pipelines & Services, net:		
NGL transportation volumes (MBPD)	2,121	1,993
NGL fractionation volumes (MBPD)	441	459
Equity NGL production (MBPD)	114	118
Fee-based natural gas processing (MMcf/d)	3,104	2,714
Onshore Natural Gas Pipelines & Services, net:		
Natural gas transportation volumes (BBtus/d)	10,339	10,672
Onshore Crude Oil Pipelines & Services, net:		
Crude oil transportation volumes (MBPD)	645	750
Offshore Pipelines & Services, net:		
Natural gas transportation volumes (BBtus/d)	1,542	1,460
Crude oil transportation volumes (MBPD)	126	244
Platform natural gas processing (MMcf/d)	777	753
Platform crude oil processing (MBPD)	3	10
Petrochemical & Refined Products Services, net:		
Butane isomerization volumes (MBPD)	90	100
Propylene fractionation volumes (MBPD)	68	67
Octane additive production volumes (MBPD)	5	10
Transportation volumes, primarily petrochemicals and refined products (MBPD)	841	788
Total, net:		
NGL, crude oil, petrochemical and refined products transportation volumes (MBPD)	3,733	3,775
Natural gas transportation volumes (BBtus/d)	11,881	12,132
Equivalent transportation volumes (MBPD) (2)	6,860	6,968

(1) Operating rates are reported on a net basis, taking into account our ownership interests in certain joint ventures, and include volumes for newly constructed assets from the related in-service dates and for recently purchased assets from the related acquisition dates.

(2) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.