ENTERPRISE PRODUCTS PARTNERS L P
Form 10-K
February 27, 2006

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

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

For the fiscal year ended December 31, 2005

OR

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

For the transition period from __________ to __________.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of Registrant as Specified in Its Charter)

Delaware	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
2727 North Loop West, Houston, Texas	**77008**
(Address of Principal Executive Offices)	(Zip Code)

(713) 880-6500

(Registrant s Telephone Number, Including Area Code)

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

Title of Each Class	Name of Each Exchange On Which Registered
Common Units	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

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

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

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

The aggregate market value of the common units of *Enterprise Products Partners L.P.* (EPD) held by non-affiliates at June 30, 2005, based on the closing price of such equity securities in the daily composite list for transactions on the New York Stock Exchange on June 30, 2005, was approximately $6.3 billion. This figure excludes common units beneficially owned by certain affiliates, including (i) Dan L. Duncan, (ii) certain trusts established for the benefit of Mr. Duncan s family and (iii) directors of Enterprise Products GP, LLC (our general partner). There were 390,303,358 common units of EPD outstanding at February 15, 2006.

ENTERPRISE PRODUCTS PARTNERS L.P.
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Waiver of Provisions of the Conflicts Policies and Procedures of 3rd Amended Administrative Services Agreement
Computation of ratio of earnings to fixed charges
List of subsidiaries
Consent of Deloitte & Touche LLP
Section 302 Certification of Robert G. Phillips
Section 302 Certification of Michael A. Creel
Section 1350 certification of Robert G. Phillips
Section 1350 certification of Michael A. Creel

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PART I

Item 1. *Business.*

GENERAL

Enterprise Products Partners L.P. is a North American midstream energy company that provides a wide range of services to producers and consumers of natural gas, natural gas liquids (NGLs), and crude oil, and is an industry leader in the development of pipeline and other midstream infrastructure in the continental United States and Gulf of Mexico. Unless the context requires otherwise, references to we, us, our, or Enterprise Products Partners are intend to mean the consolidated business and operations of Enterprise Products Partners L.P. and its subsidiaries.

We are 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. We were formed in April 1998 to own and operate certain NGL related businesses of EPCO, Inc. (EPCO). Our principal executive offices are located at 2727 North Loop West, Houston, Texas 77008 and our telephone number is (713) 880-6500.

We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P. (our Operating Partnership). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as Enterprise Products GP). Enterprise Products GP is owned 100% by Enterprise GP Holdings L.P. (Enterprise GP Holdings), a publicly traded affiliate, the common 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 EPCO. We, Enterprise Products GP, Enterprise GP Holdings and EPE Holdings are affiliates and under common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO.

In September 2004, we completed the GulfTerra Merger transactions, whereby, among other transactions, GulfTerra Energy Partners, L.P. (GulfTerra) merged with one of our wholly owned subsidiaries. As a result of the GulfTerra Merger, GulfTerra and its subsidiaries and GulfTerra s general partner (GulfTerra GP) became our wholly owned subsidiaries. The GulfTerra Merger greatly expanded our asset base to include numerous natural gas and crude oil pipelines, offshore platforms and other midstream energy assets. Additionally, the GulfTerra Merger included the purchase of various midstream assets from El Paso Corporation (El Paso) that are located in South Texas.

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. From time-to-time, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC.

We provide electronic access to our periodic and current reports on our Internet website, www.epplp.com. These reports are available on our website 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 (713) 880-6521 for paper copies of these reports free of charge.

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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
Mdth	= thousand dekatherms
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet
Mcf	= thousand cubic feet

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report contains various forward-looking statements and information that are based on our beliefs and those of Enterprise Products GP, 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, goal, forecast, intend, could and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and Enterprise Products GP believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor Enterprise Products GP 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 of this annual report. 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.

BUSINESS STRATEGY

We operate an integrated midstream asset network within the United States that includes natural gas gathering, processing, transportation and storage; NGL fractionation (or separation), transportation, storage and import and export terminaling; crude oil transportation and offshore production platform services. Our business strategy is to:

§ capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountain region and Gulf of Mexico;

§ maintain a balanced and 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 that will provide the raw materials for these projects or purchase the project s end products; and

§ increase fee-based cash flows by investing in pipelines and other fee-based businesses and de-emphasize commodity-based activities.

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, please read *Capital Spending* included under Item 7 of this annual report.

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RECENT DEVELOPMENTS

For information regarding significant events affecting us during 2005, please read *Recent Developments* included under Item 7 of this annual report, which is incorporated by reference into this Item 1.

SEGMENT DISCUSSION

Our midstream 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. We have four reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Offshore Pipelines & Services; and (iv) Petrochemical Services. Our business segments are generally organized and managed along our asset base according to the type of services rendered (or technology 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 key risk factors, please read Item 1A of this annual report. For listings and descriptions of our principal plant, pipeline and other properties by segment, please read Item 2 of this annual report.

For information regarding our general revenue recognition policies and other segment-related matters, please read Notes 4 and 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental and other matters. For a discussion of the principal effects of regulation on each of our business segments, please read *Regulation and Environmental* within each of the following segment disclosures. For a general discussion of environmental matters, please read *Other Matters Other Environmental* included within this Item 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 12,810 miles and related storage facilities including our Mid-America Pipeline System, Seminole Pipeline and Dixie Pipeline systems and (iii) NGL fractionation facilities located in Texas and Louisiana. 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, 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.

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Natural gas processing and related NGL marketing activities. At the core of our natural gas processing business are twenty-four processing plants located in Texas, Louisiana, Mississippi and New Mexico. Natural gas produced at the wellhead and 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 transmission pipeline and commercial quality specifications. In addition, on an energy equivalent basis, NGLs generally have a greater economic value as a raw material for petrochemicals and motor gasoline than their value as components of the natural gas stream. After extraction, we typically transport the mixed NGLs to a centralized facility for fractionation (or separation) 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 gas processing plants are higher than the incremental value of the NGL products that would be received by NGL extraction, 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 (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 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 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 producer s sale of the mixed NGLs we extract on their 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 extract and retain 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 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 financial instruments.

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 terminalling operations include approximately 12,810 miles of NGL pipelines, 150 million barrels of underground NGL and related product storage working capacity and two import/export facilities.

Our NGL pipelines transport mixed NGLs and other hydrocarbons to fractionation plants; distribute and collect NGL products to and from 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 consolidation). 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 in 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. Under our NGL and related product storage agreements, we collect a fee based on the number of days a customer has volumes in storage multiplied by a storage rate for each product. Accordingly, the profitability of our storage operations is primarily dependent upon the volume of material stored 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 to be delivered to our NGL storage and processing 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 charges. Accordingly, the profitability of our import and export activities primarily depends upon 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 nine NGL fractionation facilities located in Texas and Louisiana. 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.

Recoveries of mixed NGLs by 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 and Rocky Mountain 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). We are exposed to fluctuations in NGL prices to the extent we fractionate volumes for customers under percent-of-liquids arrangements. Our tolling (or fee-based) customers generally retain title to the NGLs that we process for them.

Regulation and Environmental. Our Mid-America, Seminole, Dixie, Chunchula, Lou-Tex NGL pipelines and certain pipelines in which we own equity interests, along with certain pipelines of the Louisiana Pipeline System, are interstate common carrier liquids pipelines subject to regulation by the FERC under the Interstate Commerce Act (ICA). As interstate common carriers, these liquids pipelines must provide service to any shipper who requests transportation services, provided that products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. We are required to maintain tariffs on file with the FERC that set forth the rates we charge for providing transportation services on our interstate common carrier liquids pipelines as well as the rules and regulations governing these services.

We believe that the rates charged for transportation services on our interstate common carrier liquids pipelines we own or have an interest in are just and reasonable under the ICA. However, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier liquids pipelines. Furthermore, because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

Intrastate movements of products on the Seminole, Mid-America, Belle Rose and certain pipelines of the Louisiana Pipeline System are subject to various other state laws and regulations that affect the rates we charge and the terms of service. 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.

Our NGL pipelines and services are subject to various safety and environmental statutes, including: the Hazardous Materials Transportation Act, the Hazardous Liquid Pipeline Safety Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Oil Pollution Act of 1990, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning, Pipeline Safety Improvement Act of 2002 and Community Right-to-Know Act and similar state statutes. We have ongoing programs designed to keep our gas processing plants, NGL pipelines and NGL fractionation, NGL storage and related product storage operations in compliance with environmental and safety requirements, and we believe that our facilities are in material compliance with the applicable requirements.

The U.S. Department of Transportation issued final rules (effective March 2001 with respect to hazardous liquids pipelines, which include NGL and petrochemical pipelines, and February 2004 with respect to natural gas pipelines) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and to take measures (including repairs) to protect pipeline segments located in what the rules refer to as high consequence areas. We have ongoing programs designed to keep our pipelines in compliance with environmental and safety requirements, and we believe that our facilities are in material compliance with the applicable requirements. For information regarding the costs of our pipeline integrity management program, please read Item 7 of this annual report.

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 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 in summer months 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. Our inventory cycle begins in late-February to mid-March (the seasonal low point); builds through September; 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 area 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 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.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 17,200 miles of onshore natural gas pipeline systems that provide for the gathering and transmission of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. In addition, we own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana.

Onshore natural gas pipelines. Our onshore natural gas pipeline systems provide for the gathering and transmission of natural gas from onshore developments, such as the San Juan, Barnett Shale and Permian supply basins in the Western U.S., or 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 customers or to other onshore pipelines.

Certain of our onshore natural gas pipelines generate revenue 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. 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.

Our Acadian Gas and Alabama Intrastate pipelines are exposed to commodity price risk to the extent they take title to natural gas volumes through certain of their contracts. In addition, our San Juan Gathering and Permian Basin pipeline systems 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, approximately 94% of the fee-based gathering arrangements of our San Juan Gathering System are calculated using a percentage of a regional price index for natural gas. We use commodity financial instruments from time to time to mitigate our exposure to risks related to commodity prices.

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. These facilities (our Petal Gas Storage (Petal) and 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. The high injection and withdrawal rates of such facilities also allow customers to take advantage of favorable natural gas prices and to quickly respond in situations where they have natural gas imbalance issues on pipelines connected to the storage facility. Our salt dome storage facilities permit sustained periods of high natural gas deliveries, 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) fixed monthly demand payments, which are associated with storage capacity reservation and paid regardless of the customer s usage of the storage facilities, and (ii) storage fees per unit of volume stored at the facilities.

Regulation and Environmental. Certain of our interstate natural gas pipelines and the Petal natural gas storage facility are regulated by the FERC, which approves rates, terms and other conditions under which these systems can provide services to customers. 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 any proposed rate increase by our offshore natural gas pipelines may be challenged by protest. The FERC s authority over companies that provide natural gas pipeline transportation or storage services also includes certification and construction of new facilities; the acquisition, extension, disposition or abandonment of facilities; the maintenance of accounts and records; the initiation, extension and discontinuation of covered services; and various other matters. As noted, our regulated natural gas pipelines have tariffs established through FERC filings that have a variety of terms and conditions, each of which affect the operations and profitability of each system. Generally, changes to these fees or terms are subject to approval by the FERC. In addition, our intrastate natural gas pipelines and natural gas storage facilities are subject to a variety of state and local regulations, including those that affect the rates we charge and terms of service.

Our onshore natural gas pipelines and storage facilities are subject to various safety and environmental statutes, including: the Natural Gas Act, the Natural Gas Policy Act, the Hazardous Materials Transportation Act, the Hazardous Liquid Pipeline Safety Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Oil Pollution Act of 1990, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning, Pipeline Safety Improvement Act of 2002 and Community Right-to-Know Act and similar state statutes. Our onshore natural gas pipelines and storage facilities are also subject to pipeline integrity programs as described under *NGL Pipelines & Services Regulation and Environmental.*

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At December 31, 2005 and 2004, we had a reserve of approximately $21 million for environmental remediation costs expected to be incurred by GulfTerra over time associated with mercury meters. Remediation activities were started during 2005 and are expected to take four years to complete.

Seasonality. Typically, our onshore natural gas pipelines experience higher throughput rates during the summer months as gas-fired power generation facilities increase output for residential and commercial demand for electricity for air conditioning. Likewise, seasonality impacts the timing of injections and withdrawals at our natural gas storage facilities. In the winter months, natural gas is needed as fuel for residential and commercial heating, and during the summer months, natural gas is needed by power generation facilities due to the demand for electricity for air conditioning.

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.

Offshore Pipelines & Services

Our Offshore Pipelines & Services business segment includes (i) approximately 1,190 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 870 miles of offshore Gulf of Mexico crude oil pipeline systems and (iii) seven multi-purpose offshore hub platforms located in the Gulf of Mexico.

Offshore natural gas pipelines. Our offshore natural gas pipeline systems provide for the gathering and transmission 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 transmission 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 (typically 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 they 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 oil to either onshore locations or to other offshore interconnecting pipelines.

The majority of revenues from our offshore crude oil pipelines are derived from purchase and sale arrangements whereby we purchase oil from shippers at various receipt points along our crude oil pipelines for an index-based price (less a price differential) and sell the oil back to the shippers at various redelivery points at the same index-based price. Net revenue recognized from such arrangements is based on a price differential per unit of volume (typically in barrels) multiplied by the volume delivered. In addition, certain of our offshore crude oil pipelines generate revenues based upon a gathering 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 production from reserves committed under long-term contracts for the productive life of the relevant field or contracts for the purchase and sale of crude oil with terms from two to twelve months. The revenues we earn for our services are dependent on the volume of crude oil to be delivered and the amount and term of the reserve commitment by the customer.

Offshore platforms. We have ownership interests in seven multi-purpose offshore hub platforms located in the Gulf of Mexico. Offshore platforms are critical components of the offshore 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, 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 fees and commodity charges. Demand fees represent fixed-fees charged to customers who use 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 fees and commodity charges, but demand fees generally expire after a contractually fixed period of time.

Regulation and Environmental. Certain of our offshore natural gas pipelines (primarily our High Island Offshore System) are regulated by the FERC. The jurisdiction of the FERC over these operations is similar to the FERC s jurisdiction over our interstate natural gas pipelines and the Petal natural gas storage facility as described under *Onshore Natural Gas Pipelines & Services Regulation and Environmental*.

Our offshore pipeline systems are also subject to federal regulation under the Outer Continental Shelf Lands Act (OCSLA), which calls for nondiscriminatory transportation on pipelines operating in the outer continental shelf region of the Gulf of Mexico. Each of our oil pipeline systems has continuing programs of inspection and compliance designed to keep all of our facilities in compliance with pipeline safety and pollution control requirements. We believe that our oil pipeline systems are in material compliance with the applicable requirements of these regulations.

Our offshore pipelines and platforms are subject to various safety and environmental statutes, including: the OCSLA, the Hazardous Liquid Pipeline Safety Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Oil Pollution Act of 1990, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act and similar state statutes. We have ongoing programs designed to keep our oil and natural gas pipelines and offshore platform operations in compliance with environmental and safety requirements, and we believe that our facilities are in material compliance with the applicable requirements.

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 area, 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.

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Petrochemical Services

Our Petrochemical Services business segment includes four propylene fractionation facilities, an isomerization complex, and an octane additive production facility. This segment also includes approximately 690 miles of petrochemical pipeline systems.

Propylene fractionation. Our propylene fractionation business consists primarily of four propylene fractionation facilities located in Texas and Louisiana, and approximately 620 miles of various propylene pipeline systems. These operations also include an export facility located on the Houston Ship Channel and our petrochemical marketing activities.

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 propylene can also be produced from chemical grade propylene feedstock. Chemical grade propylene is also a by-product of olefin (ethylene) production. The demand for polymer grade propylene is attributable 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 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. 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, the sales prices referenced in these contracts are market-related and can 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.

Isomerization. Our 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 normal butane, isobutane and high purity isobutane. The principal uses of isobutane are for alkylate used in the production of motor gasoline, propylene oxide and in the production of methyl tertiary butyl ether (MTBE) and isooctane. 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 additive production facility.

Octane enhancement. We own and operate an octane additive production facility located in Mont Belvieu, Texas designed to produce both isooctane and MTBE, which are motor gasoline additives that increase octane and are used in reformulated motor gasoline blends. This facility produces isooctane using feedstocks of high-purity isobutane and MTBE using feedstocks of high-purity isobutane and methanol.

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The facility s high-purity isobutane feedstock requirements are met using production from our isomerization units.

The production of MTBE was primarily driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990, which mandated the use of reformulated gasoline in certain areas of the United States. In recent years, MTBE has been detected in water supplies. The major source of ground water contamination appears to be leaks from underground storage tanks. As a result of environmental concerns, several states enacted legislation to ban or significantly limit the use of MTBE in motor gasoline within their jurisdictions. In addition, the Energy Policy Act of 2005 eliminates the requirement of oxygenates in reformulated motor gasoline.

As a result of such developments, we modified the facility to produce isooctane in addition to MTBE. These modifications were completed in mid-2005. We expect isooctane to be in demand by refiners to replace the amount of octane that is lost as a result of MTBE being eliminated as a motor gasoline blendstock. Depending on the outcome of various factors, the facility may be further modified in the future to produce alkylate, another motor gasoline additive.

Regulation and Environmental. Our interstate Lou-Tex Propylene pipeline is a common carrier pipeline regulated by the Surface Transportation Board (STB). In general, our petrochemical services operations are subject to various safety and environmental statutes, including: the Hazardous Liquid Pipeline Safety Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act, and similar state statutes. Our petrochemical pipelines are also subject to pipeline integrity programs as described under *NGL Pipelines & Services Regulation and Environmental.* We have ongoing programs designed to keep our storage operations in compliance with environmental and safety regulations, and we believe that our facilities are in material compliance with the applicable requirements.

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 and MTBE prices have been stronger during the April to September period of each year, which corresponds with the summer driving season.

Competition. We compete with numerous producers of polymer grade propylene, which include many of the major refiners on 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.

In the isomerization market, 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 also compete with other octane additive manufacturing companies primarily on the basis of price.

OTHER MATTERS

Other Environmental

We are subject to extensive federal, state and local laws and regulations governing environmental quality and pollution control. These environmental laws and regulations may, in certain instances, require us to remedy the effects on the environment of the disposal or release of specified substances at current and former operating sites. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as claims for damages to property, employees, other persons and the environment resulting from current or past operations, could result in substantial costs and liabilities in the future. It is possible that new information or future developments, such as increasingly strict environmental laws, could require us to reassess our potential exposure related to environmental matters. As this information becomes available, or other relevant developments occur, we will make expense accruals accordingly. For a summary of our significant environmental-related costs, please read Note 2 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Pipelines. Several federal and state environmental statutes and regulations may pertain specifically to the operations of our pipelines. Among these, the Hazardous Materials Transportation Act regulates materials capable of posing an unreasonable risk to health, safety and property when transported in commerce, and the Natural Gas Pipeline Safety Act and the Hazardous Liquid Pipeline Safety Act authorize the development and enforcement of regulations governing pipeline transportation of natural gas and NGLs. Although federal jurisdiction is exclusive over regulated pipelines, the statutes allow states to impose additional requirements for intrastate lines if compatible with federal programs. New Mexico, Texas and Louisiana have developed regulatory programs that parallel the federal program for the transportation of natural gas and NGLs by pipelines.

Solid Waste. The operations of our pipelines and plants may generate both hazardous and nonhazardous solid wastes that are subject to the requirements of the Resource Conservation and Recovery Act and its regulations, and other federal and state statutes and regulations. Further, it is possible that some wastes that are currently classified as nonhazardous, via exemption or otherwise, perhaps including wastes currently generated during pipeline operations, may, in the future, be designated as hazardous wastes, which would then be subject to more rigorous and costly treatment, storage, transportation, and disposal requirements. Such changes in the regulations may result in additional expenditures or operating expenses for us.

Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), and comparable state statutes, also known as Superfund laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that cause or contribute to the release of a hazardous substance into the environment. These persons include the current owner or operator of a site, the past owner or operator of a site, and companies that transport, dispose of, or arrange for the disposal of the hazardous substances found at the site. CERCLA also authorizes the Environmental Protection Agency or state agency, and in some cases, third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Despite the petroleum exclusion of CERCLA Section 101(14) that currently encompasses crude oil, refined petroleum products, natural gas and NGLs, we may nonetheless handle hazardous substances, within the meaning of CERCLA or similar state statutes, in the course of our ordinary operations.

Air. Our operations may be subject to the Clean Air Act and other federal and state statutes and regulations that impose certain pollution control requirements with respect to air emissions from operations, particularly in instances where a company constructs a new facility or modifies an existing facility. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. However, we do not believe these requirements will have a material adverse affect on our operations.

Water. The Federal Water Pollution Control Act imposes strict controls against the unauthorized discharge of pollutants, including produced waters and other oil and natural gas wastes, into navigable waters. It provides for civil and criminal penalties for any unauthorized discharges of oil and other substances and, along with the Oil Pollution Act of 1990 (OPA), imposes substantial potential liability for the costs of oil or hazardous substance removal, remediation and damages. Similarly, the OPA imposes liability for the discharge of oil into or upon navigable waters or adjoining shorelines. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of an unauthorized discharge of pollutants into state waters.

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Communication of Hazards. The Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act and comparable state statutes require those entities that operate facilities for us to organize and disseminate information to employees, state and local organizations, and the public about the hazardous materials used in our operations and our emergency planning.

Employees

At December 31, 2005, there were approximately 2,600 persons directly involved in the management, administration and operations of Enterprise Products Partners, approximately 2,365 of which are employees of EPCO that provide services to us under an administrative services agreement. The remaining 235 individuals primarily represent third-party contract personnel. For additional information regarding our relationship with EPCO, please read Item 13 of this annual report.

Significant Customers

Our revenues are derived from a wide customer base. During 2005, our largest customer, The Dow Chemical Company, accounted for 6.8% of our consolidated revenues. During 2004 and 2003, our largest customer, Shell Oil Company and affiliates (Shell), accounted for 6.5% and 5.5% of our consolidated revenues, respectively.

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Item 1A. *Risk Factors.*

An investment in our common units involves certain risks. If any of these risks were to occur, our business, results of operations, cash flows and financial condition 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.

Among the key risk factors that may have a direct impact on our business, results of operations, cash flows and financial condition are:

Risks Related to Our Business

Changes in the prices of hydrocarbon products may materially adversely affect our results of operations, cash flows and financial condition.

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 results of operations, cash flows and financial condition 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. 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. These factors include:

§ the level of domestic production;

§ 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; and

§ conservation and the extent of governmental regulation 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 results of operations, cash flows and financial position.

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

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 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.

The crude oil, natural gas and NGLs available to our facilities will be derived from reserves produced from existing wells, which reserves naturally decline over time. To offset this natural decline, our facilities will need access to additional reserves. Additionally, some of our facilities will be dependent

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on reserves that are expected to be produced from newly discovered properties that are currently being 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 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 results of operations, cash flows and financial position. Additional reserves, if discovered, may not be developed in the near future or at all.

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

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 results of operations, cash flows and financial position. For example:

Ethane. If natural gas prices increase significantly in relation to ethane prices, 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.

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. A downturn in the domestic or international economy could cause reduced demand for propylene, which could cause a reduction in the volumes of propylene that we produce and expose our investment in inventories of propane/propylene mix to pricing risk due to requirements for short-term price discounts in the spot or short-term propylene markets.

We face competition from third parties in our midstream businesses.

Even if 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:

§ geographic proximity to the production;

§ costs of connection;

§ available capacity;

§ rates; and

§ access to markets.

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

As of December 31, 2005, we had approximately $4.8 billion of consolidated debt outstanding. The amount of our future debt could have significant effects on our operations, including, among other things:

§ a significant portion of our cash flow could be dedicated to the payment of principal and interest on our future debt and may not be available for other purposes, including the payment of distributions on our common units and capital expenditures;

§ credit rating agencies may view our debt level negatively;

§ covenants contained in our existing debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;

§ our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;

§ we may be at a competitive disadvantage relative to similar companies that have less debt; and

§ we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

Our public debt indentures currently do not limit the amount of future indebtedness that we can create, incur, assume or guarantee. Although our 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 our Multi-Year Revolving Credit Facility, please read Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our Multi-Year Revolving Credit Facility and each of our indentures for our 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 our Multi-Year Revolving Credit Facility. 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 our Multi-Year Revolving Credit Facility, to terminate all commitments to extend further credit. For additional information regarding our Multi-Year Revolving Credit Facility, please read Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our ability to access capital markets to raise capital on favorable terms will be affected by our debt level, the amount of our debt maturing in the next several years and current maturities, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, difficulty 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 rates.

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.

In addition, we are experiencing increased competition 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 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 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 results of operations, cash flows and financial condition. Moreover, acquisitions and business expansions involve numerous risks, including:

§ 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, depletion 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 results of operations, cash flows and financial condition. In addition, any anticipated benefits of a material acquisition, such as expected cost savings, may not be fully realized, if at all.

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.

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Our operating cash flows from our capital projects may not be immediate.

We are engaged in several construction projects involving existing and new facilities for which significant capital has been or will be expended, 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 actual construction, development and acquisition costs could exceed forecasted amounts.

We will have significant expenditures for the development and construction of energy infrastructure assets, including some construction and development projects with significant technological challenges. We may not be able to complete our projects at the costs estimated at the time of each project s initiation.

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 13,454,498 of our common units that are owned by Enterprise GP Holdings 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 general partner and limited partner equity interests in us to service such indebtedness. Any distributions by us to such entities will be made only after satisfying our then current obligations to our creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us and Enterprise Products GP from the entities that control Enterprise Products GP, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of the entities that control our general partner were viewed as substantially lower or more risky than ours.

The 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. Our only significant assets are the equity interests we own in our subsidiaries and joint ventures. As a result, we depend upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of that cash to us in order to meet our obligations and to allow us to make distributions to our partners.

In addition, the charter documents governing our joint ventures typically vest in the joint venture management committee 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. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes.

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 behalf of us, although insurance will not cover many types of interruptions that might occur. 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. 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 and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

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

At December 31, 2005, our balance sheet reflected $494 million of goodwill and $913.6 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 (otherwise known as 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.

Increases in interest rates could materially adversely affect our business, results of operations, cash flows and financial condition.

In addition to our exposure to commodity prices, we have significant exposure to increases in interest rates. As of December 31, 2005, we had approximately $4.8 billion of consolidated debt, of which approximately $3.3 billion was at fixed interest rates and approximately $1.5 billion was at variable interest rates, after giving effect to existing interest swap arrangements. 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 results of operations, cash flows and financial condition, 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.

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

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

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

Environmental costs and liabilities and changing environmental regulation could materially 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. 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. Third parties may also have the right to pursue legal actions to enforce compliance.

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.

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 interstate 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 Natural Gas Act, 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 Department of Transportation s Office of Pipeline Safety 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 our intrastate natural gas pipelines are subject to regulation 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, please read the regulation and environmental information included under Item 1 of this annual report. This regulatory oversight can affect certain aspects of our business and the market for our products and could materially adversely affect our cash flows.

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 or pipelines 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 and our subsidiaries businesses.

We depend on the leadership, involvement and services of Dan L. Duncan, the founder of EPCO and the Chairman of our general partner. 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 any members of our senior management team could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Some of our executive officers and directors face potential conflicts of interest in managing our business.

Certain of our executive officers and directors are also officers and/or directors of EPCO, the general partner of Enterprise GP Holdings, the general partner of TEPPCO and other affiliates of EPCO. These relationships may create conflicts of interest regarding corporate opportunities and other matters. The resolution of any such conflicts may not always be in our or our unitholders best interests. In addition, these overlapping executive officers and directors allocate their time among EPCO, Enterprise GP Holdings, TEPPCO and other affiliates of EPCO. These officers and directors face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition. Please read Item 10 of this annual report for more detailed information on which of our officers and directors serve as officers and/or directors of EPCO, the general partner of Enterprise GP Holdings, the general partner of TEPPCO and other affiliates of EPCO.

Risks Related to Our Common Units as a Result of Our Partnership Structure

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

Subject to NYSE rules, 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 proportionate ownership interest of a common unit will decrease;

§ the amount of cash available for distributions on each unit may decrease;

§ the ratio of taxable income to distributions may increase;

§ the relative voting strength of each previously outstanding 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 Enterprise Products GP.

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 Enterprise Products GP. These factors include but are not limited to the following:

§ the level of our operating costs;

§ the level of competition in our business segments;

§ prevailing economic conditions;

§ the level of capital expenditures we make;

§ the restrictions contained in our debt agreements and our debt service requirements;

§ fluctuations in our working capital needs;

§ the cost of acquisitions, if any; and

§ the amount, if any, of cash reserves established by Enterprise Products GP in its sole discretion.

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

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 direct 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 Enterprise Products GP 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 Enterprise Products GP and its affiliates, including officers and directors of Enterprise Products GP, for expenses they incur on our behalf. The reimbursement of expenses could adversely affect our ability to pay cash distributions to holders of our units. Enterprise Products GP has sole discretion to determine the amount of these expenses. In addition, Enterprise Products GP and its affiliates may provide other services to us for which we will be charged fees as determined by Enterprise Products GP.

Enterprise Products GP 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 Enterprise Products GP and its affiliates have duties to manage Enterprise Products GP in a manner that is beneficial to its members. At the same time, Enterprise Products GP has duties to manage our partnership in a manner that is beneficial to us. Therefore, Enterprise Products GP 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 Enterprise Products GP or EPCO to pursue a business strategy that favors us;

§ decisions of Enterprise Products GP 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 Enterprise Products GP;

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

§ Enterprise Products GP is allowed to resolve any conflicts of interest involving us and Enterprise Products GP and its affiliates;

§ Enterprise Products GP is allowed to resolve any conflicts of interest involving us and Enterprise Products GP and its affiliates;

§ Enterprise Products GP 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 Enterprise Products GP 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 Enterprise Products GP, including TEPPCO, may compete with us in certain circumstances;

§ Enterprise Products GP 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, Enterprise Products GP 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 Enterprise Products GP 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;

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

§ Enterprise Products GP controls the enforcement of obligations owed to us by our general partner and its affiliates; and

§ Enterprise Products GP 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 and TEPPCO. For detailed information on these relationships and related transactions with these entities, please read Item 13 included within this annual report.

Even if unitholders are dissatisfied, they cannot easily remove Enterprise Products GP.

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 Enterprise Products GP or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have no practical ability to remove Enterprise Products GP or the officers or directors of Enterprise Products GP. Enterprise Products GP 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 Enterprise Products GP currently own approximately 35.6% of our outstanding common units, the removal of Enterprise Products GP as our general partner is not practicable without the consent of both Enterprise Products GP and its affiliates.

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 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 these provisions, 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.

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

If at any time Enterprise Products GP and its affiliates own 85% or more of the common units then outstanding, Enterprise Products GP 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.

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

A large number of our outstanding common units may be sold in the market, which may depress the market price of our common units.

Shell owns 29,407,549 of our common units, representing approximately 7.5% of our outstanding common units at February 15, 2006, and has publicly announced its intention to reduce its holdings of our common units on an orderly schedule over a period of years, taking into account market conditions. All of the common units held by Shell are registered for resale under our effective registration statement on Form S-3.

Sales of a substantial number of our common units in the public market could cause the market price of our common units to decline. As of February 22, 2006, we had 390,308,358 common units outstanding. Sales of a substantial number of these common units in the trading markets, whether in a single transaction or series of transactions, or the possibility that these sales may occur, could reduce the market price of our outstanding common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Tax Risks to Common Unitholders

If we were to become subject to entity level taxation for federal or 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%, and we likely would pay state taxes as well. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow though 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. Therefore, 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 entity level taxation. For example, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to our common unitholders would be reduced.

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 even if they do not 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, regulated investment companies and foreign 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), regulated investment companies (known as mutual funds), and foreign persons raises 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. Recent legislation treats net income derived from the ownership of certain publicly traded partnerships (including us) as qualifying income to a regulated investment company. 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 by 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 the common unitholder to file all United States 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.

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

None.

Item 2. ***Properties.***

The following sections provide information regarding our principal plants, pipelines and other assets by segment. For information regarding our significant historical throughput, production and processing rates, please read Item 7 of this annual report.

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.

NGL Pipelines & Services

The following table summarizes the significant NGL pipelines and related storage assets of our NGL Pipelines & Services business segment at February 1, 2006.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Useable Storage Capacity (MMBbls)
NGL pipelines: [(1)]				
Mid-America Pipeline System	Midwest and Western U.S.[(2)]	100%	7,226	
Dixie Pipeline	South and Southeastern U.S.	65.9% [(3)]	1,301	
Seminole Pipeline	Texas	90% [(4)]	1,281	
Texas NGL System [(5)]	Texas	100%	1,039	
Louisiana Pipeline System	Louisiana	Various[(6)]	655	
Promix NGL Gathering System	Louisiana	50% [(7)]	410	
Houston Ship Channel	Texas	100%	266	
Lou-Tex NGL	Texas, Louisiana	100%	204	
Others (5 systems) [(8)]	Alabama, Louisiana, Mississippi	Various	427	
Total miles			12,809	
NGL and related product storage facilities by state:				
Texas				114.9
Louisiana				13.0
Mississippi				10.9
Others (Arizona, Georgia, Iowa, Kansas, Nebraska, Oklahoma, Utah)				9.6
Total capacity [(9)]				148.4

(1) The maximum number of barrels that these systems can transport per day depends upon the operating balance achieved at a given time between various segments of the systems. Because the balance is dependent upon the mix of products to be shipped and the demand levels at the various delivery points, the exact capacities of the systems cannot be stated. We measure the utilization rates of our NGL pipelines in terms of throughput (on a net basis in accordance with our ownership interest). Total net volumes for our NGL pipelines during 2005, 2004 and 2003 were 1,360 MBPD, 1,343 MBPD and 1,196 MBPD, respectively.

(2) This system crosses thirteen states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin.

(3) We hold a 65.9% interest in this system through a majority owned subsidiary, Dixie Pipeline Company (Dixie).

(4) We hold a 90% interest in this system through a majority owned subsidiary, Seminole Pipeline Company (Seminole).

(5) Acquired in connection with the GulfTerra Merger in September 2004.

(6) Of the 655 total miles for this system, we own 100% of 559 miles; 44.3% of 53 miles; and 32.2% of the remaining 43 miles.

(7) Our ownership interest in this pipeline is held indirectly through our equity method investment in K/D/S Promix LLC (Promix).

(8) Includes our Tri-States, Belle Rose, Wilprise and Chunchula pipelines located in the coastal regions of Alabama, Louisiana and Mississippi and a pipeline held by Venice Energy Services Company, LLC (VESCO), an equity investment of ours.

(9) The 148.4 MMBbls of total useable storage capacity includes 21.3 MMBbls held under operating leases.

The following information highlights the general use of each of our principal NGL pipelines. We operate our NGL pipelines with the exception of 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 2,548-mile Rocky Mountain pipeline, the 2,740-mile Conway North pipeline and

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the 1,938-mile Conway South pipeline. 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. 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 connects the Conway hub with Kansas refineries and transports NGLs from Conway, Kansas to the Hobbs hub (with interconnections with our Seminole pipeline at the Hobbs hub). We also own fifteen unregulated propane terminals that are an integral part of the Mid-America Pipeline System.

Approximately 60% of the volumes transported on the Mid-America system are 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, and the 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 propane pipeline extending from southeast Texas and Louisiana to markets in the southeastern United States. Propane supplies transported on this system primarily originate from southeast Texas, southern Louisiana and Mississippi.

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

§ The *Texas NGL System* is a network of NGL gathering and transportation pipelines located in south Texas. The system includes 379 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 660 miles of pipelines that deliver NGLs from our South Texas fractionation facilities to refineries and petrochemical plants located from Corpus Christi to Houston and within the Texas City-Houston area, as well as to common carrier NGL pipelines.

§ The *Louisiana Pipeline System* is a network of nine NGL pipelines located in Louisiana. This system transports NGLs originating in southern Louisiana and 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 *Promix NGL Gathering System* is a NGL pipeline system that gathers mixed NGLs from natural gas processing plants in Louisiana for delivery to the Promix NGL fractionator. This gathering system is an integral part of the Promix NGL fractionation facility.

§ The *Houston Ship Channel* pipeline system is a collection of pipelines extending from our Houston Ship Channel import/export facility and Morgan s Point facility to Mont Belvieu, Texas. 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 certain of our Louisiana gas processing plants to our Mont Belvieu NGL fractionation facility.

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 our and our customers NGLs

and petrochemicals. Our underground storage facilities include locations in Arizona, Kansas and Utah that were acquired in July 2005 from Ferrellgas L.P. We operate these facilities, with the exception of certain storage locations operated for us by a third party in Louisiana and Mississippi.

The following table summarizes the significant natural gas processing and NGL fractionation assets of our NGL Pipelines & Services business segment at February 1, 2006.

Description of Asset	Location(s)	Our Ownership Interest	Net Gas Processing Capacity (Bcf/d) [2]	Total Gas Processing Capacity (Bcf/d)	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)
Natural gas processing facilities: [1, 3,4]						
Toca	Louisiana	60.3%	0.66	1.10		
Chaco [4]	New Mexico	100%	0.65	0.65		
North Terrebonne	Louisiana	44.3%	0.58	1.30		
Yscloskey	Louisiana	31.1%	0.54	1.85		
Calumet	Louisiana	31.5%	0.50	1.60		
Neptune	Louisiana	66%	0.43	0.65		
Pascagoula	Mississippi	40%	0.40	1.50		
Thompsonville [4]	Texas	100%	0.30	0.30		
Shoup [4]	Texas	100%	0.29	0.29		
Gilmore [4]	Texas	100%	0.26	0.26		
Armstrong [4]	Texas	100%	0.25	0.25		
Matagorda [4]	Texas	100%	0.25	0.25		
Others (12 facilities)[4,5]	Texas, New Mexico, Louisiana	Various[6]	1.24	5.38		
Total processing capacities			6.35	15.38		
NGL fractionation facilities: [7,8]						
Mont Belvieu	Texas	75%			158	210
Norco	Louisiana	100%			75	75
Promix	Louisiana	50%			73	145
Shoup	Texas	100%			69	69
BRF	Louisiana	32.2%			19	60
Others (4 facilities) [9]	Texas, Louisiana	Various			45	93
Total plant capacities					439	652

(1) We own direct consolidated interests in all of our natural gas processing facilities with the exception of our 13.1% interest in a facility held through our equity method investment in VESCO.

(2) 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.

(3) On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest) were approximately 53%, 61% and 63% during 2005, 2004 and 2003, respectively.

(4) As a result of the GulfTerra Merger, we acquired ownership interest in eleven natural gas processing facilities having net gas processing capacity of 2.66 Bcf/d and gross gas processing capacity of 2.8 Bcf/d.

(5) Includes our Venice, Blue Water, Sea Robin, Patterson II, Iowa and Burns Point facilities located in Louisiana; Indian Basin facility located in New Mexico; and San Martin, Delmita, Shilling, Sonora and Indian Springs facilities located in Texas. We acquired the Indians Springs facility in January 2005.

(6) Our ownership in these facilities ranges from 1.9% to 100%.

(7) On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest) were approximately 70% during each of the years 2005, 2004 and 2003.

(8) We own direct consolidated interests in all of our NGL fractionation facilities with the exception of a 50% interest in a facility held through our equity method investment in Promix; a 32.2% interest in a facility owned by Baton Rouge Fractionators LLC (BRF); and a 13.1% interest in a facility owned by VESCO.

(9) Includes our Tebone and VESCO NGL facilities located in Louisiana and our Armstrong and Delmita facilities located in Texas.

At the core of our natural gas processing business are twenty-four processing plants located in Texas, Louisiana, Mississippi and New Mexico. 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 in connection with gathering pipelines. We operate the Toca, Chaco, North Terrebonne, Calumet and Neptune plants and all of the Texas facilities.

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Our NGL marketing activities utilize a fleet of approximately 600 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. We have rail loading and unloading facilities in Arizona, Kansas, Louisiana, Mississippi and Texas. These facilities service both our rail shipments and those of our customers.

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 the facility owned by VESCO.

§ 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 Mountain Overthrust, East Texas and the Gulf Coast.

§ The *Norco* NGL fractionation facility receives mixed NGLs via pipeline from refineries and natural gas processing plants, including our Yscloskey and Toca natural gas processing plants.

§ The *Promix* NGL fractionation facility receives mixed NGLs from natural gas processing plants on the Mississippi and Alabama Gulf Coast through a connection with our Belle Rose and Tri-States NGL pipelines. In addition to the 410-mile Promix NGL pipeline, Promix owns five NGL storage caverns and a barge loading facility that are integral to its operations.

§ Our *Shoup* NGL fractionation facility fractionates mixed NGLs supplied by our South Texas natural gas processing facilities.

§ The *BRF* facility processes mixed NGLs from production fields in Alabama, Mississippi and southern Louisiana as well as offshore Gulf of Mexico areas.

Our NGL operations include import and export facilities located on the Houston Ship Channel in southeast Texas. We lease an import facility that can offload NGLs from tanker vessels at a rate of 10,000 barrels per hour. In addition, we own an export facility that can load cargoes of refrigerated propane and butane onto tanker vessels at rates of up to 5,000 barrels per hour. In addition, 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 119 MBPD, 91 MBPD and 79 MBPD for 2005, 2004 and 2003, respectively.

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Onshore Natural Gas Pipelines & Services

The following table summarizes the significant assets of our Onshore Natural Gas Pipelines & Services business segment at February 1, 2006.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Approximate Capacity, Natural Gas (MMcf/d)	Gross Capacity (Bcf)
Onshore natural gas pipelines:[1]					
Texas Intrastate System[2]	Texas	100%[3]	8,222	4,975	
San Juan Gathering System[2]	New Mexico, Colorado	100%	5,404	1,100	
Permian Basin System[2]	Texas, New Mexico	100%	1,477	490	
Acadian Gas System	Louisiana	100%[4]	1,027	954	
Alabama Intrastate System[2]	Alabama	100%	402	200	
Other (4 systems)[5]	Texas, Mississippi	Various[6]	684		
Total miles			17,216		
Natural gas storage facilities:					
Petal[2]	Mississippi	100%			11.9
Hattiesburg[2]	Mississippi	100%			4.0
Wilson[2]	Texas	Leased[7]			6.4
Acadian	Louisiana	Leased[8]			3.0
Total gross capacity					25.3

(1) On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest) were approximately 73%, 75% and 63% during 2005, 2004 and 2003, respectively.

(2) Acquired in connection with the GulfTerra Merger in September 2004.

(3) We own a 50% undivided interest in the 733-mile Channel pipeline system, which is a component of the Texas Intrastate System.

(4) We own 100% of 1,000 miles of the Acadian Gas System and 49.5% of the related 27-mile Evangeline natural gas pipeline.

(5) Includes the Delmita, Big Thicket and Indian Springs gathering systems located in Texas and the Petal pipeline 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 Indian Springs gathering system in January 2005.

(6) We own 100% of these assets with the exception the Indian Springs system, in which we indirectly own an 80% equity interest in this system through a majority owned subsidiary.

(7) Facility held under an operating lease that expires in January 2008, which contains certain renewal options.

(8) Facility held under an operating lease that expires in December 2012.

The following information highlights the general use of each of our principal onshore natural gas pipelines and storage facilities, all of which we operate.

- 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 consumers. This 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 Ship Channel industrial market. The Texas Intrastate System is comprised of the 7,292-mile GulfTerra Texas Intrastate pipeline system, the 197-mile TPC Offshore gathering system and the 733-mile Channel pipeline system. The Wilson natural gas storage facility is an integral part of the Texas Intrastate System.

- The *San Juan Gathering System* serves natural gas producers in the San Juan Basin of New Mexico and Colorado. This system gathers natural gas production from over 10,450 wells in the San Juan Basin and delivers the natural gas to natural gas processing facilities, including our Chaco facility.

- The *Permian Basin 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 Permian Basin System is comprised of the 674-mile Waha system and 803-mile Carlsbad system.

§ 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, 423-mile Acadian pipeline and the 27-mile Evangeline pipeline. The Acadian natural gas storage facility is an integral part of the Acadian Gas System.

§ The *Alabama Intrastate System* 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.

§ Our *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.

Offshore Pipelines & Services

The following table summarizes the significant assets of our Offshore Pipelines & Services business segment at February 1, 2006, 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:[1]					
Manta Ray Offshore Gathering System	25.7%[2]	250		206	
High Island Offshore System[3]	100%	204		1,800	
Viosca Knoll Gathering System[3]	100%	162		1,000	
Green Canyon Laterals[3]	Various[4]	136		649	
Anaconda Gathering System[3]	100%	136		550	
Nautilus System	25.7%[2]	101		154	
East Breaks System[3]	100%	85		400	
Phoenix Gathering System[3]	100%	78		450	
Nemo Gathering System	33.9%[5]	24		102	
Falcon Gas Pipeline[3]	100%	14		400	
Total miles		1,190			
Offshore crude oil pipelines:[6]					
Cameron Highway Oil Pipeline[3]	50%[7]	378			250
Poseidon Oil Pipeline System[3]	36%[8]	324			144
Constitution Oil Pipeline	100%	70			80
Allegheny Oil Pipeline[3]	100%	43			140
Marco Polo Oil Pipeline[3]	100%	36			120
Typhoon Oil Pipeline[3]	100%	16			80
Tarantula Oil Pipeline[3]	100%	4			30
Total miles		871			
Offshore platforms: [3,9]					
Ship Shoal 332A[10]	62%		438		
Ship Shoal 332B[10]	50%[7]		438		
Marco Polo	50%[11]		4,300	150	60
Viosca Knoll 817	100%		671	140	5
Garden Banks 72	50%		518	40	18
East Cameron 373	100%		441	195	3
Falcon Nest	100%		389	400	3

(1) On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest) were approximately 30%, 32% and 41% during 2005, 2004 and 2003, respectively.

(2) Our ownership interest in this pipeline is held indirectly through our equity method investment in Neptune Pipeline Company, LLC.

(3) Acquired in connection with the GulfTerra Merger in September 2004. Data shown for the Anaconda Gathering System includes our recently completed 30-mile Constitution Gas Pipeline, which has a net capacity of approximately 200 MMcf/d.

(4) Our ownership interests in the Green Canyon Laterals ranges from 2.7% to 100%.

(5) Our ownership interest in this pipeline is held indirectly through our equity method investment in Nemo Gathering Company, LLC.

(6) On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest) were approximately 17% and 27% during 2005 and 2004, respectively.

(7) Our ownership interest in this asset is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company (Cameron Highway).

(8) Our ownership interest in this asset is held indirectly through our equity method investment in Poseidon Oil Pipeline Company, LLC.

(9) On a weighted-average basis, utilization rates during 2005 and 2004 for these assets (based on the periods that we held an ownership interest) were approximately 26% and 32% in connection with natural gas capacity and approximately 9% and 14% for crude oil capacity, respectively.

(10) These platforms serve as pipeline junctions; therefore, we do not have processing capacities to report for these assets.

(11) Our ownership interest in this platform is held indirectly through our equity method investment in Deepwater Gateway, LLC.

The following information highlights the general use of each of our principal Gulf of Mexico offshore natural gas pipelines. We operate our offshore natural gas pipelines, with the exception of the Manta Ray Offshore Gathering System, Nautilus System, Nemo Gathering System and certain components of the Green Canyon Laterals.

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

§ The *Green Canyon Laterals* consist of 28 pipeline laterals (which are extensions of natural gas pipelines) that transport natural gas to downstream pipelines, including the HIOS.

§ The *Anaconda Gathering System* connects our Marco Polo platform and Constitution Gas Pipeline to the ANR pipeline system. The Anaconda Gathering System includes our wholly-owned Constitution Gas Pipeline, which was completed in late 2005 and serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico. We initiated flows into our Constitution Gas Pipeline during the first quarter of 2006.

§ The *Nautilus System* connects our Manta Ray Offshore Gathering System to our Neptune natural gas processing plant.

§ The *East Breaks System* connects the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25 to the 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 *Nemo Gathering System* transports natural gas from Green Canyon developments to an interconnect with our Manta Ray Offshore Gathering System.

§ The *Falcon 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 following information highlights the general use of each of our principal Gulf of Mexico offshore crude oil pipelines, all of which we operate.

§ The *Cameron Highway Oil Pipeline*, which commenced operations during the first quarter of 2005, 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.

§ 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.

§ The *Constitution Oil Pipeline* was completed in late 2005 and serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico. Initial throughput volumes were received during the first quarter of 2006. The Constitution Oil Pipeline connects with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at a 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* gathers crude oil from our Marco Polo platform to an interconnect with our Allegheny Oil Pipeline in Green Canyon Block 164.

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 Marco Polo platform and East Cameron 373.

§ The *Ship Shoal 332A* platform is a junction platform, which serves as a location for crude oil and natural gas to enter our system of assets. Crude oil and natural gas produced in the deepwater Gulf of Mexico is transported to the Ship Shoal 332A platform via several third-party pipelines. Crude oil enters our Poseidon Oil Pipeline System and Allegheny Oil Pipelines at the Ship Shoal 332 A platform, and natural gas enters our Manta Ray Offshore Gathering System.

§ The *Ship Shoal 332B* platform is a junction platform for crude oil pipelines. Crude oil produced in the deepwater Gulf of Mexico is transported to the Ship Shoal 332B platform on our Poseidon Oil Pipeline System and Constitution Oil Pipeline and third-party pipelines. The crude oil is then shipped off this platform via our Cameron Highway Oil Pipeline.

§ 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 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 currently processes natural gas from the Falcon field.

Petrochemical Services

The following table summarizes the significant assets of our Petrochemical Services segment at February 1, 2006.

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)	Length (Miles)
Propylene fractionation facilities:(1)					
Mont Belvieu (3 plants)	Texas	Various(2)	58	72	
BRPC	Louisiana	30%(3)	7	23	
Total capacity			65	95	
Isomerization facility:					
Mont Belvieu(4)	Texas	100%	116	116	
Petrochemical pipelines:(5)					
Lou-Tex Propylene	Texas, Louisiana	100%			291
Lake Charles	Texas, Louisiana	50%(6)			88
Others (7 systems)(7)	Texas, Louisiana	Various(8)			311
Total miles					690
Octane additive production facilities:					
Mont Belvieu	Texas	100%	*(Dual Use)*(9)		

(1) On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest) were approximately 83%, 86% and 88% during 2005, 2004 and 2003, respectively.

(2) We own a 54.6% interest and lease the remaining 45.4% of a facility having 17 MBPD of plant capacity. We own a 66.7% interest in a second facility having 41 MBPD of total plant capacity. We own 100% of the remaining facility, which has 14 MBPD of plant capacity.

(3) Our ownership interest in this facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator, LLC (BRPC).

(4) On a weighted-average basis, utilization rates for this facility were approximately 70% for 2005 and 66% for each of 2004 and 2003.

(5) The maximum number of barrels that these systems can transport per day depends upon the operating balance achieved at a given time between various segments of the systems. Because the balance is dependent upon the mix of products to be shipped and the demand levels at the various delivery points, the exact capacities of the systems cannot be stated. We measure the utilization rates of our petrochemical pipelines in terms of throughput (on a net basis in accordance with our ownership interest). Total net volumes for our petrochemical pipelines during 2005, 2004 and 2003 were 64 MBPD, 71 MBPD and 68 MBPD, respectively.

(6) Of the 88 total miles for this pipeline, we own 50% of 82 miles and 100% of the remainder.

(7) Includes our Port Neches, Bay Area, Texas City, La Porte, Morgan s Point and other petrochemical pipelines located in Texas and our Sabine Propylene pipeline located in Texas and Louisiana.

(8) We own 100% of these pipelines with the exception of (i) 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 GP, LLC and (ii) the 16-mile Bay Area pipeline, in which we own an undivided 66% interest.

(9) This facility is capable of producing either isooctane or MTBE as conditions warrant. At full capacity, the facility can produce approximately 12 MBPD of isooctane or 15.5 MBPD of MTBE. On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest and the products produced) were approximately 29%, 83% and 62% during 2005, 2004 and 2003, respectively. The facility was capable of producing only MTBE prior to mid-2005.

We produce polymer grade propylene at our Mont Belvieu facilities 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 ExxonMobil Corporation into chemical grade propylene. The production of polymer grade propylene from our Mont Belvieu plants is primarily used in our petrochemical marketing activities.

The Lou-Tex Propylene pipeline is used to transport propylene from Sorrento, Louisiana to Mont Belvieu, Texas. Currently, this pipeline is used to transport chemical grade propylene. 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. We operate all of the assets in our Petrochemical Services business segment.

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Item 3. ***Legal Proceedings.***

On occasion, we are named as a defendant in litigation relating to our normal business operations, 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 activity. We are not aware of any significant litigation, pending or threatened, that may have a significant adverse effect on our financial position or results of operations.

A number of lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing MTBE, although generally such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary that owns the facility. It is possible, however, that MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits. In connection with our purchase of additional equity interests in the owner of the octane-additive production facility in 2003 from an affiliate of Devon Energy Corporation (Devon) and in 2004 from an affiliate of Sunoco, Inc. (Sun), Devon and Sun indemnified us for any related liability (including liabilities described above) that are in respect of periods prior to the date we purchased such interests. There are no dollar limits or deductibles associated with the indemnities we received from Sun and Devon with respect to potential claims linked to the period of time they held ownership interests in the facility.

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

None.

PART II

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

Market Information and Cash Distributions

Our common units are listed on the NYSE under the ticker symbol EPD. As of February 15, 2006, there were an estimated 920 unitholders of record of our common units. The following table sets forth the high and low sales prices for our common units during the periods indicated (as reported by the NYSE Composite Transaction Tape) and the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2004					
1st Quarter	$24.720	$21.750	$0.3725	Apr. 30, 2004	May 12, 2004
2nd Quarter	$23.840	$20.000	$0.3725	Jul. 30, 2004	Aug. 6, 2004
3rd Quarter	$23.700	$20.190	$0.3950	Oct. 29, 2004	Nov. 5, 2004
4th Quarter	$25.990	$22.730	$0.4000	Jan. 31, 2005	Feb. 14, 2005
2005					
1st Quarter	$28.350	$23.150	$0.4100	Apr. 29, 2005	May 10, 2005
2nd Quarter	$27.090	$24.770	$0.4200	Jul. 29, 2005	Aug. 10, 2005
3rd Quarter	$27.660	$23.500	$0.4300	Oct. 31, 2005	Nov. 8, 2005
4th Quarter	$26.020	$23.380	$0.4375	Jan. 31, 2006	Feb. 9, 2006

The quarterly cash distributions shown in the table above correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., the payments made to our partners) occur within 45 days after the end of such quarter. We expect to fund our quarterly cash distributions to partners primarily with cash provided by operating activities. For additional information regarding our cash flows from operating activities, please read *Liquidity and Capital Resources* included under Item 7 of this annual report. Although the payment of cash dividends is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

Recent Sales of Unregistered Securities

There were no sales of unregistered equity securities during 2005.

Common Units Authorized for Issuance Under Equity Compensation Plan

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

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during 2005. In December 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, intended to repurchase up to 2,000,000 of our common units for the purpose of granting options to management and key employees (amount adjusted for the 2-for-1 unit split in May 2002). As of February 15, 2006, we and our affiliates are authorized to repurchase up to 618,400 additional common units under this repurchase program.

Item 6. ***Selected Financial Data.***

The following table presents selected historical financial data of Enterprise Products Partners. This information has been derived from our audited financial statements for the periods indicated and should be read in conjunction with the audited financial statements included under Item 8 of this annual report. In addition, information regarding our results of operations and liquidity and capital resources can be found under Item 7 of this annual report. As presented in the table, amounts (except per unit data) are in thousands.

	Year Ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Operating results data:[1]					
Revenues	$ 12,256,959	$ 8,321,202	$ 5,346,431	$ 3,584,783	$ 3,154,369
Income from continuing operations[2]	$ 423,716	$ 257,480	$ 104,546	$ 95,500	$ 242,178
Income per unit from continuing operations:[3]					
Basic	$ 0.92	$ 0.83	$ 0.42	$ 0.55	$ 1.70
Diluted	$ 0.92	$ 0.83	$ 0.41	$ 0.48	$ 1.39
Other financial data:					
Distributions per common unit[4]	$ 1.698	$ 1.540	$ 1.470	$ 1.360	$ 1.194
Commodity hedging income (loss)[5]	$ 1,095	$ 448	$ (619)	$ (51,344)	$ 101,290

	As of December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Financial position data:[1]					
Total assets	$ 12,591,016	$ 11,315,461	$ 4,802,814	$ 4,230,272	$ 2,424,692
Long-term and current maturities of debt[6]	$ 4,833,781	$ 4,281,236	$ 2,139,548	$ 2,246,463	$ 855,278
Partners equity[7]	$ 5,679,309	$ 5,328,785	$ 1,705,953	$ 1,200,904	$ 1,146,922
Total units outstanding (excluding treasury)[7]	389,861	364,786	217,780	183,810	174,542

(1) In general, our historical operating results and financial position have been affected by numerous acquisitions since 2001. Our most significant transaction to date was the GulfTerra Merger, which was completed on September 30, 2004. The aggregate value of the total consideration we paid or issued to complete the GulfTerra Merger was approximately $4 billion. The GulfTerra Merger and our other acquisitions were accounted for using purchase accounting; therefore, the operating results of these acquired entities are included in our financial results prospectively from their respective purchase dates. For additional information regarding such transactions, please read Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

(2) Amounts presented for 2005 and 2004 are prior to the cumulative effect of accounting changes.

(3) Earnings per unit and unit count data prior to 2002 have been adjusted to reflect the May 2002 two-for-one split of each class of our partnership units.

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

(5)

Income from continuing operations includes our gain or loss from commodity hedging activities. A variety of factors influence whether or not a particular hedging strategy is successful. As a result of incurring significant losses from commodity hedging transactions in early 2002 due to a rapid increase in natural gas prices, we exited those commodity hedging strategies that created the losses. Since that time, we have utilized only a limited number of commodity financial instruments. For additional information regarding our use of financial instruments, please read Item 7A of this annual report.

(6) 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 growth capital spending.

(7) We regularly issue common units through public offerings and, less frequently, in connection with acquisitions or other transactions. The increase in partners equity since 2001 has been the result of such transactions, with the September 2004 issuance of 104.5 million of common units in connection with the GulfTerra Merger being our largest. For additional information regarding our partners equity and unit history, please read Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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

For the years ended December 31, 2005, 2004 and 2003.

Enterprise Products Partners L.P. is a North American midstream energy company that provides a wide range of services to producers and consumers of natural gas, natural gas liquids (NGLs), and crude oil, and is an industry leader in the development of pipeline and other midstream assets in the continental United States and Gulf of Mexico. Unless the context requires otherwise, references to we, us, our, or Enterprise Products Partners are intended to mea the consolidated business and operations of Enterprise Products Partners L.P. and its subsidiaries.

We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P. (our Operating Partnership). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as Enterprise Products GP). Enterprise Products GP is owned 100% by Enterprise GP Holdings L.P. (Enterprise GP Holdings), a publicly traded affiliate listed on the New York Stock Exchange (NYSE) under the ticker symbol EPE. We, Enterprise Products GP and Enterprise GP Holdings are affiliates and under common control of Dan L. Duncan, the Chairman and the controlling shareholder of EPCO, Inc. (EPCO).

This annual report contains various forward-looking statements and information based on our beliefs and those of Enterprise Products GP, as well as assumptions made by us and information currently available to us. Please read the section titled *Cautionary Statement Regarding Forward-Looking Information* included under Item 1 of this annual report.

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
Mdth	= thousand dekatherms
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet
Mcf	= thousand cubic feet

RECENT DEVELOPMENTS

The year 2005 was a challenging year for Enterprise Products Partners. The Gulf Coast region experienced two major hurricanes (Katrina and Rita) that affected our employees, suppliers, customers and industry. Our thoughts remain with those displaced by these storms and we are well-positioned to assist the Gulf Coast energy industry in the rebuilding effort. Although certain of our facilities incurred structural damage as a result of the storms and other operations were interrupted, by year-end the majority of our operated facilities were at pre-hurricane production, transportation or processing levels. In particular, our Toca natural gas processing facility, which is located in coastal Louisiana and was heavily damaged in Hurricane Katrina, has recently returned to operations. For information regarding our insurance claims related to these storms, please read Note 22 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our growth capital spending for 2005 was a record of $743.8 million, which includes $338.6 million for our Independence Hub offshore platform and related Independence Trail Pipeline and $90.1 million for our Constitution Oil and Constitution Gas Pipelines. In addition, we recently announced two new natural gas processing projects in the Rockies. We expect that these projects will enhance our existing asset base and provide us with additional growth opportunities in the future. In addition to our growth capital projects, we completed $326.6 million in acquisitions during 2005, the largest of which was the $145.5 million purchase of underground NGL storage facilities and propane terminals from Ferrellgas L.P.

(Ferrellgas). For additional information regarding our growth capital spending and acquisitions, please read *Capital Spending* included within this Item 7.

During 2005, we completed the integration of our legacy operations with those of GulfTerra Energy Partners L.P. (GulfTerra). In September 2004, we completed the GulfTerra Merger transaction, whereby GulfTerra merged with one of our wholly owned subsidiaries. As a result of the GulfTerra Merger, GulfTerra and its subsidiaries and GulfTerra s general partner (GulfTerra GP) became our wholly owned subsidiaries. The GulfTerra Merger greatly expanded our asset base to include numerous natural gas and crude oil pipelines, offshore platforms and other midstream energy assets. Additionally, the GulfTerra Merger included the purchase of various midstream assets from El Paso that are located in South Texas. For additional information regarding the GulfTerra Merger, please read Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our Cameron Highway Oil Pipeline began deliveries of Gulf of Mexico crude oil production during the first quarter of 2005 to major refining markets along the Texas Gulf Coast. The Cameron Highway Oil Pipeline can transport up to 500 MBPD of deepwater Gulf of Mexico crude oil production. We own a 50% interest in this system through our equity method investment in Cameron Highway Oil Pipeline Company (Cameron Highway).

We completed construction of the Constitution Oil and Constitution Gas Pipelines in 2005. We own and operate these pipelines, which provide production gathering services for the Constitution and Ticonderoga fields in the Gulf of Mexico. Initial throughput is expected on the Constitution pipelines during the first quarter of 2006.

In May 2003, GulfTerra commenced a project relating to its San Juan Basin assets. The San Juan Optimization Project was substantially complete in 2005 at an approximate cost of $31 million. This project resulted in a 10% increase of capacity on our San Juan Gathering System and will increase market opportunities through a new interconnect with the Transwestern Pipeline. We connected a record 336 natural gas wells to the San Juan Gathering System during 2005.

In February 2005, we sold 17,250,000 common units (including an over-allotment amount of 2,250,000 common units which closed in March 2005), which generated net proceeds of approximately $456.7 million. In addition, our Operating Partnership sold $500 million of senior notes in February 2005. In March 2005, we filed a universal shelf registration statement with the SEC registering the issuance of up to $4 billion of additional partnership equity and/or public debt obligations. In June 2005, our Operating Partnership sold $500 million of senior notes under this registration statement. In December 2005, we sold 4,000,000 common units under this registration statement, which generated net proceeds of $98.7 million. For additional information regarding our debt obligations and capital structure, please see Notes 14 and 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

In October 2005, our Operating Partnership amended its revolving credit facility to increase total bank commitments from $750 million to $1.25 billion (which may be further increased to $1.4 billion upon our request, subject to certain conditions). The increase in borrowing capacity under our Multi-Year Revolving Credit Facility further enables us to meet future funding requirements of our growth capital projects. For additional information regarding our debt obligations, please see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The ownership of our general partner underwent a number of changes during 2005. In January 2005, affiliates of EPCO acquired a 9.9% membership interest in Enterprise Products GP and 13,454,498 of our common units from El Paso for approximately $425 million in cash. As a result of these transactions, EPCO and its affiliates owned 100% of the membership interests of Enterprise Products GP. In August 2005, EPCO and its affiliates contributed their membership interests in Enterprise Products GP to Enterprise GP Holdings. Affiliates of EPCO currently own 86.5% of Enterprise GP Holdings. For additional information regarding these transactions between related parties, please read Item 13 of this annual report.

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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. In recent 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. Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions.

We believe that we are positioned to continue to grow through construction of new facilities and acquisitions that will expand our system of assets and through growth capital projects. We estimate our consolidated capital spending during 2006 will approximate $1.8 billion, which includes estimated expenditures of approximately $1.7 billion for growth capital projects and acquisitions and approximately $78 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based upon our strategic operating and growth plans, which are also dependent upon our ability to generate capital from operating cash flows or otherwise obtain the capital necessary to accomplish our objectives. Our forecast may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Further, our forecast may change as a result of decisions made 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 the principal factor that determines how much we can spend. 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.

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

	For Year Ended December 31, 2005	2004	2003
Capital spending for business combinations and asset purchases:			
GulfTerra Merger:			
Cash payments to El Paso, including amounts paid to acquire certain South Texas midstream assets		$ 655,277	
Transaction fees and other direct costs		24,032	
Cash received from GulfTerra		(40,313)	
Net cash payments		638,996	
Value of non-cash consideration issued or granted		2,910,771	
Total GulfTerra Merger consideration		3,549,767	
Indirect interests in the Indian Springs natural gas gathering and processing assets	$ 74,854		
Additional ownership interests in Dixie Pipeline Company (Dixie)	68,608		
NGL underground storage and terminalling assets purchased from Ferrellgas	145,522		
Other business combinations and asset purchases	37,618	85,851	$ 37,348
Total	326,602	3,635,618	37,348
Capital spending for property, plant and equipment:			
Growth capital projects, net	743,827	114,419	125,600
Sustaining capital projects	73,622	32,509	20,313
Total	817,449	146,928	145,913
Capital spending attributable to unconsolidated affiliates:			
Purchase of 50% interest in GulfTerra GP in connection with the initial step of the GulfTerra Merger			425,000
Other investments in and advances to unconsolidated affiliates	88,044	64,412	46,927
Total	88,044	64,412	471,927
Total capital spending	$ 1,232,095	$ 3,846,958	$ 655,188

As shown in the preceding table, capital spending for growth capital projects is presented net of contributions in aid of construction costs of $47 million, $8.9 million and $0.9 million during 2005, 2004 and 2003, respectively. On certain of our capital projects, third parties may be 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.

Our significant capital spending transactions during 2005 include the following:

§ We paid El Paso $74.9 million for indirect majority ownership interests in the 89-mile Indian Springs Gathering System and the Indian Springs natural gas processing facility, both of which are located in East Texas.

§ We paid $68.6 million for an additional 46% interest in Dixie from affiliates of ConocoPhillips and ChevronTexaco. As a result of these acquisitions, Dixie is now a majority-owned consolidated subsidiary of ours.

§ We purchased three NGL underground storage facilities and four propane terminals from Ferrellgas for $145.5 million in cash. The underground storage facilities are located in Kansas, Arizona and Utah and have a combined capacity of 6.1 MMBbls. Approximately 70% of the aggregate storage capacity is leased to third party customers under fee-based contracts. The four propane terminals are located in Minnesota and North Carolina. The Minnesota facilities are connected to our Mid-America Pipeline System, and the North Carolina terminals are connected by rail to our facilities on the Gulf Coast. As part of the transaction, Ferrellgas has contracted with us to maintain a certain level of storage volume and terminal throughput for five years with the option to extend for an additional five years.

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Significant Recently Announced Growth Capital Projects

Jonah Expansion. In February 2006, we and TEPPCO Partners, L.P. (TEPPCO), affiliate of EPCO, entered into a letter of intent related to the formation of a joint venture to expand TEPPCO s Jonah Gas Gathering System (the Jonah system), located in the Green River Basin in southwestern Wyoming. The proposed expansion of the Jonah system would increase the natural gas gathering and transportation capacity of the Jonah system from 1.5 Bcf/d to 2.0 Bcf/d.

The letter of intent stipulates that we will be responsible for all activities related to the construction of the expansion of the Jonah system, including advancing of all expenditures necessary to plan, engineer and construct the expansion project. We estimate that total funds needed for this project will approximate $200 million and that the expansion assets will be placed in service in late 2006.

The amounts we advance to complete the expansion of the Jonah system will constitute a subscription for an equity interest in the proposed joint venture. TEPPCO has the option to return to us up to 100% of the amounts we advance (i.e., the subscription amounts). If TEPPCO returns any portion of the subscription to us, the relative interests of us and TEPPCO in the new joint venture would be adjusted accordingly. The proposed joint venture arrangement will terminate without liability to either party if TEPPCO returns 100% of the advances we make in connection with the expansion project, including carrying costs and expenses.

The general partner of TEPPCO and 2,500,000 common units of TEPPCO are owned by an affiliate of Mr. Duncan, Chairman of the board of directors of our general partner.

Piceance Basin Gas Processing Project. In January 2006, we announced the execution of a minimum 15-year natural gas processing agreement with an affiliate of the EnCana Corporation (EnCana). Under that agreement, we will have the right to process up to 1.3 Bcf/d of EnCana s natural gas production from the Piceance Basin area of western Colorado. To accommodate this production, we have begun construction of the Meeker natural gas processing facility in Rio Blanco County, Colorado. In addition, we will construct a 50-mile NGL pipeline that will connect our Meeker facility with our Mid-America Pipeline System. Phase I, which includes construction of the plant and pipeline, will provide us with 750 MMcf/d of natural gas processing capacity and the ability to recover up to 35 MBPD of NGLs. Phase II, which includes the expansion of the plant, will expand natural gas processing capacity at the facility to 1.3 Bcf/d and increase NGL extraction rates to up to 70 MBPD. We expect Phase I and Phase II to be operational by mid-2007 and late-2008, respectively. Phase I is expected to cost $284 million.

Wyoming Gas Processing Projects. In January 2006, we announced our intent to purchase from TEPPCO the Pioneer natural gas processing plant located in Opal, Wyoming and the rights to process natural gas originating from the Jonah and Pinedale fields in the Greater Green River Basin in Wyoming. Upon execution of definitive agreements, the receipt of all necessary regulatory approval and approvals from the boards of directors of TEPPCO and our general partner, we would purchase the Pioneer plant for $36 million and commence construction to increase its processing capacity from 275 MMcf/d to 550 MMcf/d at an additional expected cost of $21 million. We expect this expansion to be completed in mid-2006.

We have also announced our intent to build a new gas processing plant with a capacity of 650 MMcf/d adjacent to the Pioneer plant. We expect to place the new facility in service during 2007. The Pioneer expansion and the new natural gas processing plant will serve growing natural gas production in the Jonah and Pinedale fields. The cost of this new processing facility is expected to be $228 million.

Natural Gas Storage Expansion. In December 2005, we completed the conversion of an existing brine well located at our Petal, Mississippi storage facility to a 2.4 Bcf natural gas storage cavern at a cost of $15 million. Due to strong demand for natural gas storage, we have commenced the development of an additional storage cavern at the Petal facility that is expected to add 5 Bcf of storage capacity. This cavern is expected to cost $75 million and be placed in service during the first quarter of 2008.

Expansion of Mont Belvieu NGL and Petrochemical Storage Services. In November 2005, we announced an expansion of our NGL and petrochemical storage services at our complex in Mont Belvieu, Texas to improve our ability to receive and deliver NGLs and petrochemicals. The Mont Belvieu expansion projects include the drilling of two new brine production wells and the construction of two above-ground brine storage pits. The increased brine storage capability will further enable us to enhance product storage services and movement to transportation and distribution pipelines that serve the Gulf Coast region, as well as our import and export facilities on the Houston Ship Channel. As a result of these projects, we will also more than double our above-ground brine storage capabilities to 19 MMBbls and will increase our capacity to produce brine. These projects are expected to be placed in service in 2006 and 2007 and are expected to cost $77 million.

Hobbs NGL Fractionator. In June 2005, we announced plans to construct a new NGL fractionator, designed to handle up to 75 MBPD of mixed NGLs, located at the interconnection of our Mid-America Pipeline System and our Seminole Pipeline near Hobbs, New Mexico. Additionally, we will construct a purity ethane storage well near the new fractionator and reconfigure the interconnection between our Mid-America Pipeline System and the Seminole Pipeline. These projects are expected to cost $175 million and be placed in service by mid-2007. Our Hobbs NGL fractionator will process the increase in mixed NGLs resulting from our Phase I expansion of the Mid-America Pipeline System.

Mid-America Pipeline System Phase I Expansion. In January 2005, we announced an expansion of the Rocky Mountain segment of our Mid-America Pipeline System to accommodate an expected increase in mixed NGLs originating from producing basins in Wyoming, Utah, Colorado and New Mexico. The expansion project will be completed in stages and will increase throughput volumes on the segment by a total of 50 MBPD. We expect final completion of the Phase I expansion during the second quarter of 2007 at a cost of $187 million. We expect to receive the necessary regulatory approval and begin construction on our Phase I expansion project in the first quarter of 2006.

Expansion of Mont Belvieu NGL Fractionator. In January 2005, we began a project to expand the processing capacity of our Mont Belvieu NGL fractionator from 210 MBPD to 225 MBPD and to reduce energy costs. This expansion project will enable us to accommodate a portion of an expected increase in NGL production from the Rocky Mountains. The project is expected to cost approximately $41 million and be completed in mid-2006.

Independence Hub Platform and Independence Trail Pipeline System. In November 2004, we entered into an agreement with the Atwater Valley Producers Group for the dedication, processing and gathering of natural gas and condensate production from several natural gas fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas (collectively, the anchor fields) of the deepwater Gulf of Mexico. First production is expected in 2007.

We are constructing and will own the Independence Hub platform, which will be located in Mississippi Canyon Block 920, at a water depth of 8,000 feet. The Independence Hub is a 105-foot deep-draft, semi-submersible platform with a two-level production deck, which will process 1 Bcf/d of natural gas. The platform, which is estimated to cost $420 million, will be operated by Anadarko, and is designed to process production from its anchor fields and has excess payload capacity to support ten additional pipeline risers. In December 2004, we entered into an agreement with Cal Dive International Inc. (Cal Dive) to sell them a 20% indirect interest in the Independence Hub platform.

Additionally, we will construct, own, and operate the 134-mile Independence Trail natural gas pipeline system, which will have a throughput capacity of 1 Bcf/d of natural gas. The pipeline system, which is estimated to cost $268 million, will transport production from the Independence Hub platform to the Tennessee Gas Pipeline.

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 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 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 connection with the regulations for hazardous liquid pipelines, we developed a pipeline integrity management program in 2002. In connection with the regulations for natural gas pipelines, we developed a pipeline integrity management program in 2004.

During 2005, we spent approximately $42.2 million to comply with these programs, of which $25 million was recorded as an operating expense, and the remaining $17.2 million was capitalized. We spent approximately $22.4 million to comply with these programs during 2004, of which $14.9 million was recorded as an operating expense and the remaining $7.5 million was capitalized.

We expect our net cash outlay for pipeline integrity program expenditures to approximate $63.2 million during 2006. Our forecast is net of certain costs we expect to recover from El Paso. In April 2002, GulfTerra acquired several midstream assets located in Texas and New Mexico from El Paso. These assets include the Texas Intrastate System and the Permian Basin System. El Paso agreed to indemnify GulfTerra for any pipeline integrity costs it incurred (whether paid or payable) during 2005, 2006 and 2007 with respect to such assets, to the extent that such annual costs exceed $3.3 million; however, the aggregate amount reimbursable by El Paso for these periods is capped at $50.2 million. During 2006, we expect to recover $13.8 million from El Paso related to our 2005 expenditures, which leaves a remainder of $36.4 million reimbursable by El Paso for 2006 and 2007 pipeline integrity costs.

RESULTS OF OPERATIONS

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

We evaluate segment performance based on the non-generally accepted accounting principle (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 financial measure calculated using accounting principles generally accepted in the United States of America (GAAP) 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 (or consolidated) segment gross operating margin as operating income before: (i) depreciation and amortization expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses on the sale of assets; and (iv) general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principles. 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.

For additional information regarding our business segments, please read Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

We have historically included equity earnings from 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, which may be suppliers of raw materials or consumers of finished products. 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 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 and petrochemicals. Our asset system has multiple entry points. In general, hydrocarbons can enter our asset system in a number of ways, including an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an NGL gathering pipeline, an NGL fractionator, an NGL storage facility, an NGL transportation or distribution pipeline or an onshore natural gas pipeline. At each link along this asset system, we earn revenues based on volume or an ownership of products such as NGLs.

Many of our equity investments are present within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process NGLs extracted by our gas plants. The NGLs received from Promix then can be sold in our NGL marketing activities. Given the integral nature of our equity investees to our operations, we believe treatment of earnings from our equity method investees as a component of gross operating margin and operating income is appropriate.

For additional information regarding our investments in and advances to unconsolidated affiliates, please read Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Selected Price and Volumetric Data

The following table illustrates selected average quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products since the beginning of 2003:

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound
	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
2003									
1st Quarter	$ 6.58	$ 34.12	$ 0.43	$ 0.65	$ 0.76	$ 0.80	$ 0.85	$ 0.24	$ 0.21
2nd Quarter	$ 5.40	$ 29.04	$ 0.39	$ 0.53	$ 0.58	$ 0.62	$ 0.65	$ 0.25	$ 0.19
3rd Quarter	$ 4.97	$ 30.21	$ 0.37	$ 0.56	$ 0.67	$ 0.68	$ 0.73	$ 0.21	$ 0.15
4th Quarter	$ 4.58	$ 31.18	$ 0.40	$ 0.58	$ 0.73	$ 0.71	$ 0.75	$ 0.22	$ 0.16
Average for Year	$ 5.38	$ 31.14	$ 0.40	$ 0.58	$ 0.68	$ 0.70	$ 0.74	$ 0.23	$ 0.18
2004									
1st Quarter	$ 5.69	$ 35.25	$ 0.43	$ 0.66	$ 0.76	$ 0.76	$ 0.87	$ 0.29	$ 0.26
2nd Quarter	$ 6.00	$ 38.34	$ 0.45	$ 0.65	$ 0.79	$ 0.79	$ 0.92	$ 0.32	$ 0.26
3rd Quarter	$ 5.75	$ 43.90	$ 0.52	$ 0.79	$ 0.92	$ 0.92	$ 1.05	$ 0.32	$ 0.27
4th Quarter	$ 7.07	$ 48.31	$ 0.60	$ 0.85	$ 1.03	$ 1.04	$ 1.15	$ 0.40	$ 0.35
Average for Year	$ 6.13	$ 41.45	$ 0.50	$ 0.74	$ 0.88	$ 0.88	$ 1.00	$ 0.33	$ 0.29
2005									

1st Quarter	$ 6.27	$ 49.68	$ 0.52	$ 0.79	$ 0.98	$ 1.00	$ 1.14	$ 0.45	$ 0.39
2nd Quarter	$ 6.74	$ 53.09	$ 0.52	$ 0.82	$ 0.98	$ 1.01	$ 1.16	$ 0.37	$ 0.30
3rd Quarter	$ 8.53	$ 63.08	$ 0.69	$ 0.97	$ 1.14	$ 1.26	$ 1.36	$ 0.37	$ 0.33
4th Quarter	$ 13.00	$ 60.03	$ 0.76	$ 1.06	$ 1.27	$ 1.34	$ 1.36	$ 0.50	$ 0.44
Average for Year	$ 8.64	$ 56.47	$ 0.62	$ 0.91	$ 1.09	$ 1.15	$ 1.26	$ 0.42	$ 0.37

(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 an 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.

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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, and reflect the periods in which we owned an interest in such operations. In general, the increase in volumes since 2003 is due to the assets we acquired in connection with the GulfTerra Merger, which was completed on September 30, 2004.

	For Year Ended December 31,		
	2005	2004	2003
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	1,478	1,411	1,275
NGL fractionation volumes (MBPD)	292	307	227
Equity NGL production (MBPD)	85	95	43
Fee-based natural gas processing (MMcf/d)	1,767	1,692	194
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	5,916	5,638	600
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	1,780	2,081	433
Crude oil transportation volumes (MBPD)	127	138	
Platform gas processing (BBtus/d)	252	306	
Platform oil processing (MBPD)	7	14	
Petrochemical Services, net:			
Butane isomerization volumes (MBPD)	81	76	77
Propylene fractionation volumes (MBPD)	55	57	57
Octane additive production volumes (MBPD)	6	10	4
Petrochemical transportation volumes (MBPD)	64	71	68
Total, net:			
NGL, crude oil and petrochemical transportation volumes (MBPD)	1,669	1,620	1,343
Natural gas transportation volumes (BBtus/d)	7,696	7,719	1,033
Equivalent transportation volumes (MBPD) (1)	3,694	3,651	1,615

(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 most significant recent event affecting our results of operations was the GulfTerra Merger and related transactions. Since the closing date of the GulfTerra Merger was September 30, 2004, our Statements of Consolidated Operations do not include any earnings from GulfTerra prior to October 1, 2004. The effective closing date of our purchase of the South Texas midstream assets was September 1, 2004. As a result, our Statements of Consolidated Operations for 2004 include four months of earnings from the South Texas midstream assets. The results of operations from our other 2005, 2004 and 2003 business combinations and asset purchases are also included in our earnings from the date of their respective acquisitions.

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

	For the Year Ended December 31,		
	2005	2004	2003
Revenues	$12,256,959	$8,321,202	$5,346,431
Operating costs and expenses	11,546,225	7,904,336	5,046,777
General and administrative costs	62,266	46,659	37,590

Equity in income (loss) of unconsolidated affiliates	14,548	52,787	(13,960)
Operating income	663,016	422,994	248,104
Interest expense	230,549	155,740	140,806
Net income	419,508	268,261	104,546

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Revenues from the sale and marketing of NGL products within the NGL Pipelines & Services business segment accounted for 67% of total consolidated revenues for each of 2005 and 2004 and 68% of total consolidated revenues for 2003. Revenues from the sale of petrochemical products within the Petrochemical Services segment accounted for 11%, 13% and 12% of total consolidated revenues for 2005, 2004 and 2003, respectively. Revenues from the transportation, sale and storage of natural gas using onshore assets accounted for 13%, 10% and 11% of total consolidated revenues for 2005, 2004 and 2003, respectively.

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

	Year Ended December 31,		
	2005	**2004**	**2003**
Gross operating margin by segment:			
NGL Pipelines & Services	$ 579,706	$374,196	$310,677
Onshore Natural Gas Pipelines & Services	353,076	90,977	18,345
Offshore Pipeline & Services	77,505	36,478	5,561
Petrochemical Services	126,060	121,515	75,885
Other, non-segment		32,025	(53)
Total segment gross operating margin	$1,136,347	$655,191	$410,415

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for taxes, minority interest and cumulative effect of changes in accounting principles, please read *Other Items* included within this Item 7.

Comparison of Year Ended December 31, 2005 with Year Ended December 31, 2004

Revenues for 2005 increased $3.9 billion over those recorded during 2004. The trend in consolidated revenues can be attributed to (i) a $2.2 billion increase in revenues from our NGL and petrochemical marketing activities resulting from an increase in sales volumes and energy commodity prices in 2005 relative to 2004; (ii) the addition of $1.5 billion in revenues from acquired or consolidated businesses, particularly those generated by the GulfTerra and South Texas midstream assets and (iii) a $0.2 billion increase in revenues from the sale of natural gas attributable to higher natural gas prices year-to-year.

Consolidated costs and expenses increased $3.7 billion year-to-year primarily due to (i) higher energy commodity prices, which resulted in a $2.2 billion increase in the cost of sales of natural gas, NGLs and petrochemical products and (ii) the addition of $1.4 billion in costs and expenses attributable to acquired or consolidated businesses. General and administrative costs increased $15.6 million period-to-period as a result of our expanded business activities.

Changes in our revenues and costs and expenses period-to-period are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was 91 cents per gallon (CPG) during 2005 versus 73 CPG during 2004 a year-to-year increase of 25%. 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, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub) averaged $8.64 per MMBtu during 2005 versus $6.13 per MMBtu during 2004. Polymer grade propylene index prices increased 27% year-to-year and refinery grade propylene index prices increased 28% year-to-year. For historical pricing information of natural gas, crude oil and NGLs, please see the table on page 50.

Equity earnings from unconsolidated affiliates decreased $38.2 million year-to-year. Equity earnings for 2005 include a full year of our share of earnings from investments we acquired in connection with the GulfTerra Merger, including an $11.5 million charge associated with the refinancing of Cameron Highway s project debt. Fiscal 2004 includes $32 million of equity earnings from GulfTerra GP, which we consolidated in September 2004 as a result of completing the GulfTerra Merger. Collectively, the

aforementioned changes in revenues, costs and expenses and equity earnings contributed to a $240 million increase in operating income year-to-year.

Interest expense increased $74.8 million year-to-year primarily due to debt we incurred in 2004 as a result of the GulfTerra Merger and the issuance of additional senior notes in 2005. Our average debt principal outstanding was $4.6 billion in 2005 compared to $2.8 billion in 2004.

As a result of items noted in the previous paragraphs, net income increased $151.2 million year-to-year to $419.5 million in 2005 compared to $268.3 million in 2004. Net income for both years includes the recognition of non-cash amounts related to the cumulative effects of changes in accounting principles. We recorded a $4.2 million charge in 2005 and a $10.8 million benefit in 2004 related to such changes. For additional information regarding the cumulative effect of changes in accounting principles we recorded in 2005 and 2004, please read Note 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Due to our geographic and business diversification, Hurricanes Katrina (August 2005) and Rita (September 2005) had varying effects across our business segments. The hurricanes impacted supply and demand for natural gas, NGLs, crude oil and motor gasoline. In general, this resulted in an increase in energy commodity prices, which was exacerbated in certain regions due to local supply and demand imbalances. The disruptions in natural gas, NGL and crude oil production along the U.S. Gulf Coast resulted in decreased volumes for some of our pipeline systems, natural gas processing plants and NGL fractionators, which in turn caused a decrease in our gross operating margin from certain operations. In addition, operating costs at certain of our plants and pipelines were negatively impacted due to the higher fuel costs. These adverse effects were mitigated by increases in gross operating margin from certain of other operations, which benefited from increased demand for NGLs and octane additives, regional demand for natural gas and the general increase in commodity prices.

We estimate that Hurricanes Katrina and Rita reduced our gross operating margin in 2005 by approximately $48 million as a result of decreased transportation and processing volumes and higher hurricane-related expenses and insurance premium costs. Our 2005 results of operations reflect a $4.8 million cash receipt related to the settlement of certain business interruption insurance claims from Hurricane Ivan in September 2004.

We are at varying stages of the insurance claims process with respect to these hurricanes and expect to receive additional insurance recoveries in 2006 and 2007. For additional information regarding our insurance claims related to these storm events, please read *Results of Operations Significant Risks and Uncertainties Hurricanes* included within this Item 7.

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 $579.7 million for 2005 versus $374.2 million for 2004. The $205.5 million increase in gross operating margin consists of the following: (i) a $186.9 million increase from natural gas processing and related NGL marketing activities, (ii) a $21.3 million increase from NGL fractionation and (iii) a $2.7 million decrease from NGL pipelines and related storage services.

The $186.9 million year-to-year increase in gross operating margin from natural gas processing and related NGL marketing activities includes $122.3 million from natural gas plants acquired in connection with the GulfTerra Merger and $66.9 million from NGL marketing activities. Our marketing activities benefited from higher sales volumes and commodity prices during 2005 compared to 2004.

The $21.3 million year-to-year increase in gross operating margin from NGL fractionation includes (i) $14.9 million of improved results from our Mont Belvieu facility, (ii) $14 million from assets acquired in connection with the GulfTerra Merger and (iii) a $9 million decrease from our Louisiana NGL fractionators, particularly Norco, which suffered a loss of processing volumes due to Hurricane Katrina. Our Norco NGL fractionator is expected to return to normal operating rates during 2006.

The $2.7 million year-to-year decrease in gross operating margin from NGL pipelines and related storage services was due to a variety of reasons, including (i) a net $11.2 million decrease from our Mid-America Pipeline System and Seminole Pipeline primarily due to higher fuel costs and pipeline integrity expenses, (ii) a $4.9 million decrease from our Louisiana Pipeline System primarily due to hurricane effects, (iii) a net $6.9 million increase from our import and export facilities and related Houston Ship Channel pipeline attributable to increased volumes, and (iv) a net $8.9 million increase due to acquired assets and consolidation of former equity method investees.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $353.1 million for 2005 compared to $91 million for 2004. The $262.1 million increase in gross operating margin is primarily due to onshore natural gas pipelines and storage assets acquired in connection with the GulfTerra Merger. Gross operating margin from this segment is largely attributable to contributions from our San Juan Gathering System, Texas Intrastate System and Permian Basin System, which together generated gross operating margins in 2005 of $290.4 million. Our Petal and Hattiesburg natural gas storage facilities generated $38.7 million of gross operating margin in 2005. The San Juan Gathering System, Texas Intrastate System, Permian Basin System and Petal and Hattiesburg natural gas storage facilities were acquired in connection with the GulfTerra Merger.

Offshore Pipelines & Services. Gross operating margin from this business segment was $77.5 million for 2005 compared to $36.5 million for 2004. The $41 million increase in gross operating margin is primarily due to offshore Gulf of Mexico assets acquired in connection with the GulfTerra Merger. The year-to-year change in gross operating margin consists of the following: (i) a $20.1 million increase from offshore natural gas pipelines, (ii) a $26.4 million increase from offshore platforms and (iii) a $5.5 million decrease from offshore crude oil pipelines, which includes an $11.5 million charge related to the refinancing of Cameron Highway s project debt in 2005.

Petrochemical Services. Gross operating margin from this business segment was $126.1 million for 2005 compared to $121.5 million during 2004. The $4.6 million increase in gross operating margin is primarily due to improved results from isomerization services and octane additive production activities, both of which benefited from increased demand for motor gasoline in 2005.

Other. Gross operating margin from this segment pertains to equity earnings we recorded from GulfTerra GP prior to its consolidation with our financial results in September 2004.

Comparison of Year Ended December 31, 2004 with Year Ended December 31, 2003

Revenues for 2004 increased $3 billion over those recorded during 2003. The increase in consolidated revenues can be attributed to (i) a $2.1 billion increase in revenues from our NGL and petrochemical marketing activities primarily resulting from an increase in sales volumes and energy commodity prices in 2004 relative to 2003 and (ii) the addition of $0.8 billion in revenues from acquired assets and business combinations, particularly those resulting from the GulfTerra Merger in September 2004.

Consolidated costs and expenses increased $2.9 billion year-to-year primarily due to (i) higher energy commodity prices, which resulted in a $2 billion increase in the cost of sales of our NGL and petrochemical marketing activities; (ii) the addition of $0.6 billion in costs and expenses attributable to acquired or consolidated businesses during 2004; and (iii) a $0.2 billion increase in the costs of our natural gas processing business primarily due to an increase in volumes. General and administrative costs increased $9.1 million year-to-year as a result of expanded business activities.

As noted previously, changes in our revenues and costs and expenses year-to-year are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was 73 CPG during 2004 versus 57 CPG during 2003 a year-to-year increase of 28%. The market price of natural gas averaged $6.13 per MMBtu during 2004 versus $5.38 per MMBtu during 2003. Polymer grade propylene index prices increased 44% year-to-year and refinery grade propylene index prices increased 61% year-to-year.

Equity earnings from unconsolidated affiliates increased $66.7 million year-to-year. Fiscal 2004 includes $32 million of equity earnings from GulfTerra GP, which we acquired in December 2003. Fiscal 2003 includes a $22.5 million non-cash asset impairment charge related to our octane additive production facility. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to a $174.9 million increase in operating income year-to-year.

Interest expense increased $14.9 million year-to-year primarily due to debt we incurred in 2004 as a result of the GulfTerra Merger. Our average debt principal outstanding was $2.8 billion during 2004 compared to $2 billion during 2003.

As a result of the items noted in previous paragraphs, net income increased $163.8 million to $268.3 million for 2004 compared to $104.5 million for 2003. Net income for 2004 includes a $10.8 million benefit associated with the cumulative effect of changes in accounting principles.

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

NGL Pipelines & Services. Gross operating margin from this business segment was $374.2 million for 2004 versus $310.7 million for 2003. The $63.5 million increase in gross operating margin includes (i) a $82 million increase from our natural gas processing business, which includes $61.2 million from assets acquired in connection with the GulfTerra Merger, (ii) a $20.9 million decrease from our NGL pipelines and related storage services resulting from an increase in pipeline integrity expenses and a decrease in transportation volumes on certain of our pipelines and (iii) a $6.8 million increase from our NGL fractionation business, which includes $5.8 million associated with the South Texas NGL fractionators we acquired in connection with the GulfTerra Merger.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $91 million for 2004 compared to $18.3 million for 2003. The $72.7 million increase in gross operating margin for this segment is also attributable to assets acquired in connection with the GulfTerra Merger.

Offshore Pipelines & Services. Gross operating margin from this business segment was $36.5 million for 2004 compared to $5.6 million for 2003. The $30.9 million increase from this segment is primarily due to offshore Gulf of Mexico assets acquired in connection with the GulfTerra Merger.

Petrochemical Services. Gross operating margin from this business segment was $121.5 million in 2004 compared to $75.9 million in 2003. Gross operating margin from our octane additive production business increased $34.4 million year-to-year primarily due to our consolidation of the results of operations of Belvieu Environmental Fuels (BEF). We acquired a controlling ownership interest in BEF, which owns our octane additive production facility, in September 2003. In addition, the results of operations for 2003 include the recognition by us of our share (or $22.5 million) of a $67.5 million non-cash asset impairment charge recorded by BEF prior to its consolidation. Gross operating margin from propylene fractionation increased $10.1 million year-to-year primarily due to higher petrochemical marketing sales volumes, which benefited from the effects of higher polymer grade propylene prices in 2004 relative to 2003.

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Significant Risks and Uncertainties — Hurricanes

The following is a discussion of the general status of insurance claims related to recent hurricanes that affected our assets. 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 to us.

Hurricane Ivan insurance claims. Our final purchase price allocation for the GulfTerra Merger includes a $26.2 million receivable for insurance claims related to expenditures to repair property damage to certain GulfTerra assets caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004 prior to the GulfTerra Merger. These expenditures represent our costs to restore the damaged facilities to operation. Since this loss event occurred prior to completion of the GulfTerra Merger, the claim was filed under the insurance program of GulfTerra and El Paso. Since year end 2005, we received cash reimbursements from insurance carriers totaling $24.1 million related to these property damage claims, and we expect to recover the remaining $2.1 million by mid-2006. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

In addition, we have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan. During the fourth quarter of 2005, we received $4.8 million from such claims. In addition, we estimate an additional $15 million to $16 million will be received during the first quarter of 2006. To the extent we receive cash proceeds from such business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period in which funds are received.

Hurricanes Katrina and Rita insurance claims. Hurricanes Katrina and Rita affected certain of our Gulf Coast assets in August and September of 2005, respectively. Inspection, evaluation of property damage to our facilities and repairs are a continuing effort. We expensed $5 million during the third quarter of 2005 related to property damage insurance deductibles for these storms. To the extent that insurance proceeds from property damage claims do not cover our actual cash expenditures (in excess of the insurance deductibles we have expensed), such shortfall will be expensed when realized. We recorded $15.5 million of estimated recoveries from property damage claims based on amounts expended through December 31, 2005. In addition, we expect to file business interruption claims for losses related to these hurricanes. To the extent we receive cash proceeds from such business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period of receipt.

General Outlook for 2006

We expect our results of operations to be affected by the following key trends and events during 2006.

§ We believe that drilling activity in the major producing areas where we operate, including the Rocky Mountains, San Juan Basin and deepwater Gulf of Mexico, will result in increased demand for our midstream energy services. As a result, we expect higher transportation and processing volumes for our assets due to increased natural gas and crude oil production from both the Rocky Mountains and deepwater Gulf of Mexico. Hurricanes Katrina and Rita reduced natural gas and crude oil production in the Gulf of Mexico during the latter half of 2005. Barring any other major storms or similar disruptions, we believe that Gulf of Mexico production will return to pre-hurricane levels by mid-2006.

§ We are currently in a major asset construction phase that began in 2005. With several major projects underway and announced to begin this year, fiscal 2006 will be a transition year as we continue to invest in multiple projects that will further diversify our portfolio of midstream assets. We believe that completion of these projects will generate additional cash flows beginning in 2006. Our significant growth capital projects are supported by long-term agreements with producers in significant supply basins, which include the Piceance Basin in Colorado, the Jonah and Pinedale fields in the Greater Green River Basin in Wyoming and the deepwater Gulf of Mexico.

§ We believe that our natural gas and NGL facilities located in central Louisiana and our Marco Polo Oil Pipeline, Marco Polo platform and Cameron Highway Oil Pipeline located in the Gulf of Mexico are poised to benefit as production volumes increase from developments in the Southern Green Canyon area of the deepwater Gulf of Mexico. Volumes on our Cameron Highway Oil Pipeline were adversely affected during the fourth quarter of 2005 due to disruption of production caused by Hurricanes Katrina and Rita, and these volumes are expected to continue to be adversely affected during the first quarter of 2006. However, we currently expect significant increases in Cameron Highway Oil Pipeline volumes during the remainder of 2006 as production increases, including production at the Mad Dog field and initial production from the Ticonderoga, K2 North and Timon fields.

§ We believe that the strength of the domestic and global economy will continue to drive increased demand for all forms of energy despite higher commodity prices. Our largest NGL consuming customers in the ethylene industry continue to see strong demand for their products, which enables them to raise prices to mitigate higher fuel and feedstock costs. With the unusually high price of crude oil relative to natural gas, ethane and propane are the preferred feedstocks for the ethylene industry.

LIQUIDITY AND CAPITAL RESOURCES

Our primary cash requirements, in addition to normal operating expenses and debt service, are for capital expenditures, business acquisitions and distributions to our partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and short-term revolving credit arrangements. Capital expenditures for long-term needs resulting from internal growth projects and business acquisitions are expected to be funded by a variety of sources (either separately or in combination) including cash flows from operating activities, borrowings under commercial bank credit facilities, the issuance of additional equity and debt securities. 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, 2005, we had $42.1 million of unrestricted cash on hand and approximately $727 million of available credit under our Operating Partnership s Multi-Year Revolving Credit Facility.

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In total, we had approximately $4.8 billion in principal outstanding under various debt agreements at December 31, 2005.

As a result of our growth objectives, we expect to access debt and equity capital markets from time-to-time and we believe that financing arrangements to support our growth activities can be obtained on reasonable terms. Furthermore, we believe that maintenance of an investment grade credit rating combined with continued ready access to debt and equity capital at reasonable rates and sufficient trade credit to operate our businesses efficiently provide a solid foundation to meet our long and short-term liquidity and capital resource requirements.

For additional information regarding our growth strategy, please read *Capital Spending* included within this Item 7.

Credit Ratings

At February 15, 2006, the credit ratings of our Operating Partnership s debt securities were Baa3 with a stable outlook as rated by Moody s Investor Services; BBB- with a stable outlook as rated by Fitch Ratings; and BB+ with a stable outlook as rated by Standard and Poor s.

In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, the Operating Partnership entered into a $54 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 the Operating Partnership s credit rating by Moody s declines below Baa3 in combination with our credit rating at Standard & Poor s remaining at BB+ or lower, the $54 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.

Registration Statements

From time-to-time, we issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. In March 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of equity and debt securities. After taking into account our issuance of securities under this universal registration statement during 2005, we can issue an additional $3.4 billion of securities under this registration statement as of February 15, 2006.

During 2003, we instituted a distribution reinvestment plan (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. We have a registration statement on file with the SEC covering the issuance of up to 15,000,000 common units in connection with the DRIP. A total of 10,925,102 common units have been issued under this registration statement through February 15, 2006.

We also 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. A total of 260,222 common units have been issued to employees under this plan through February 15, 2006.

For information regarding our public debt obligations or partnership equity, please read Note 14 and 15, respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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Debt Obligations

For detailed information regarding our consolidated debt obligations and those of our unconsolidated affiliates, please read Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. The following table summarizes our consolidated debt obligations at the dates indicated (dollars in thousands):

	December 31,	
	2005	**2004**
Operating Partnership debt obligations:		
364-Day Acquisition Credit Facility, variable rate, repaid in February 2005[1]		$ 242,229
Multi-Year Revolving Credit Facility, variable rate, due October 2010	$ 490,000	321,000
Seminole Notes, 6.67% fixed-rate, repaid December 2005		15,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes A, 8.25% fixed-rate, repaid March 2005		350,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes E, 4.00% fixed-rate, due October 2007	500,000	500,000
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	500,000
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	650,000
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	350,000
Senior Notes I, 5.00% fixed-rate, due March 2015[2]	250,000	
Senior Notes J, 5.75% fixed-rate, due March 2035[3]	250,000	
Senior Notes K, 4.950% fixed-rate, due June 2010[4]	500,000	
Dixie Revolving Credit Facility, variable rate, due June 2007	17,000	
Debt obligations assumed from GulfTerra	5,068	6,469
Total principal amount	4,866,068	4,288,698
Other, including unamortized discounts and premiums and changes in fair value[5]	(32,287)	(7,462)
Subtotal long-term debt	4,833,781	4,281,236
Less current maturities of debt[6]		(15,000)
Long-term debt	$4,833,781	$4,266,236
Standby letters of credit outstanding	$ 33,129	$ 139,052

(1) We used the proceeds from our February 2005 common unit offering to fully repay and terminate the 364-Day Acquisition Credit Facility. For additional information regarding this equity offering, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

(2) Senior Notes I were issued at 99.379% of their face amount in February 2005.

(3) Senior Notes J were issued at 98.691% of their face amount in February 2005.

(4) Senior Notes K were issued at 99.834% of their face amount in June 2005.

(5) The December 31, 2005 amount includes $18.2 million related to fair value hedges and $14.1 million in net unamortized discounts. The December 31, 2004 amount includes $1.8 million related to fair value hedges and $9.2 million in net unamortized discounts.

(6) In accordance with Statement of Financial Accounting Standards (SFAS) No. 6, *Classification of Short-Term Obligations Expected to Be Refinanced*, long-term and current maturities of debt at December 31, 2004, reflected (i) our refinancing of Senior Notes A with proceeds from our Senior Notes I and J in March 2005 and (ii) the repayment of our 364-Day Acquisition Facility using proceeds from an equity offering completed in February 2005.

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Our significant debt-related transactions during 2005 were as follows:

§ In February 2005, we completed repayment of the 364-Day Acquisition Credit Facility using proceeds from our February 2005 equity offering.

§ Also in February 2005, we issued $500 million in aggregate principal amount of Senior Notes I and J. A portion of the proceeds from these Senior Notes were used to repay Senior Notes A, which matured in March 2005.

§ In June 2005, we issued $500 million in aggregate principal amount of Senior Notes K.

§ In October 2005, the borrowing capacity under the Operating Partnership s Multi-Year Revolving Credit Facility was increased from $750 million to $1.25 billion, with the possibility that the borrowing capacity could be increased further to $1.4 billion (subject to certain conditions). In addition, the maturity date for debt outstanding under this facility was extended from September 2009 to October 2010.

§ In December 2005, Seminole Pipeline Company, a majority-owned subsidiary, made the final payment on its indebtedness.

We have three unconsolidated affiliates with long-term debt obligations. The following table summarizes the debt obligations of these unconsolidated affiliates (on a 100% basis to the joint venture) at December 31, 2005 and our ownership interest in each entity on that date (dollars in thousands):

	Our Ownership Interest	**Total**
Cameron Highway	50.0%	$ 415,000
Poseidon	36.0%	95,000
Evangeline	49.5%	30,650
Total		$ 540,650

For information regarding the scheduled maturities of our consolidated debt obligations and estimated cash payments for interest, please read *Contractual Obligations* within this Item 7.

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 thousands). For information regarding the individual components of our cash flow amounts, please see the Statements of Consolidated Cash Flows included under Item 8 of this annual report.

	For Year Ended December 31,		
	2005	**2004**	**2003**
Net cash provided from operating activities	$ 631,708	$391,541	$424,705
Net cash used in investing activities	1,130,395	941,424	662,076
Net cash provided by financing activities	516,229	543,973	254,020

We prepare our Statements of Consolidated Cash Flows 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 the like, (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, and (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of assets or gains or losses from the 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 balances are influenced by changes in commodity prices and the quantity of products held in connection with our marketing activities.

In addition, noncash items that were subtracted in determining income must be added back in determining net cash flows from operating activities. Each of these noncash items is a charge against income but does not decrease cash. Items to be added back include depreciation, amortization of intangibles, amortization in interest expense, operating lease expense paid by EPCO, provisions for impairments of long-lived assets and increases in deferred tax liabilities. Conversely, noncash items that were added in determining income (such as amortization of bond premiums or decreases in deferred tax liabilities) must be subtracted in determining net cash flows from operating activities.

Equity in income or loss from unconsolidated affiliates is also a non-cash item that must be removed in determining net cash flows from operating activities. Our cash flows from operating activities reflect the actual cash distributions we receive from such investees.

Net cash provided from operating activities is 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 and crude oil. 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. Reduced demand for our services or products by industrial customers, whether because of 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 thus the availability of cash from operating activities. For a more complete discussion of these and other risk factors pertinent to our business, please read Item 1A of this annual report.

Cash used in investing activities primarily represents expenditures for capital projects, business combinations, asset purchases and investments in unconsolidated affiliates. Cash provided by (or used in) 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 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 Year Ended December 31, 2005 with Year Ended December 31, 2004

Operating activities. Net cash provided from operating activities was $631.7 million in 2005 compared to $391.5 million in 2004. The $240.2 million, or 61%, year-to-year increase in net cash provided from operating activities is primarily due to:

§ Net income adjusted for all non-cash items and the net effects of changes in operating accounts increased $252.1 million year-to-year primarily due to the addition of earnings from assets acquired in connection with the GulfTerra Merger in September 2004.

§ Distributions received from unconsolidated affiliates decreased by $12 million year-to-year primarily due to the consolidation of GulfTerra GP in September 2004 partially offset by increased cash distributions from offshore Gulf of Mexico investments. GulfTerra GP accounted for $32.3 million in cash distributions from unconsolidated affiliates during 2004.

The carrying value of our inventories increased from $189 million at December 31, 2004 to $339.6 million at December 31, 2005. The $150.6 million increase is primarily due to higher commodity prices during 2005 when compared to 2004 and an increase in volumes purchased and held in inventory in connection with our marketing activities at December 31, 2005 versus December 31, 2004.

Investing activities. Cash used in investing activities was $1.1 billion in 2005 compared to $941.4 million in 2004. Expenditures for growth and sustaining capital projects (net of contributions in aid of construction costs) increased $670.5 million year-to-year primarily due to cash payments associated with our offshore Gulf of Mexico projects. Our cash outlays for asset purchases and business combinations were $326.6 million in 2005 versus $724.7 million in 2004. The 2004 period includes $638.8 million paid to El Paso in connection with the GulfTerra Merger.

Our investments in unconsolidated affiliates increased to $87.3 million in 2005 from $57.9 million in 2004. In 2005, we contributed $72 million to Deepwater Gateway, L.L.C. to fund our share of the repayment of its term loan. During 2004, we used $27.5 million to acquire additional ownership interests in Promix, which owns the Promix NGL fractionator, and contributed $24 million to Cameron Highway for the construction of its crude oil pipeline.

Cash flows related to investing activities for 2005 also include (i) a $47.5 million cash receipt related to the partial return of our investment in Cameron Highway and (ii) a $42.1 million cash receipt from the sale of our investment in Starfish Pipeline Company, LLC (Starfish). The sale of our Starfish investment was required by the FTC in order to gain its approval for the GulfTerra Merger.

For additional information related to our capital spending program, please read *Capital Spending* included within this Item 7.

Financing activities. Cash provided by financing activities was $516.2 million in 2005 compared to $544 million in 2004. We had net borrowings under our debt agreements of $561.7 million during 2005 versus $125.6 million during 2004. During 2005, we issued an aggregate $1 billion in senior notes, the proceeds of which were used to temporarily reduce debt outstanding under our bank credit facilities, repay Senior Notes A and for general partnership purposes, including capital expenditures, asset purchases and business combinations. In addition, we repaid the remaining $242.2 million that was outstanding at the end of 2004 under our 364-Day Acquisition Credit Facility using proceeds from our February 2005 equity offering. We used the net proceeds from our November 2005 equity offering to temporarily reduce amounts outstanding under our Multi-Year Revolving Credit Facility.

In September 2004, we borrowed $2.8 billion under our bank credit facilities (principally the 364-Day Acquisition Credit Facility) to fund $655.3 million in cash payment obligations to El Paso in connection with the GulfTerra Merger; purchase $1.1 billion of GulfTerra s senior and senior subordinated notes in connection with our tender offers; and repay $962 million outstanding under GulfTerra s revolving credit facility and secured term loans. In October 2004, we issued an aggregate $2 billion in senior notes, the proceeds of which were used to reduce indebtedness outstanding under our bank credit facilities. Our repayments of debt during 2004 also reflect the use of $563.1 million of net proceeds from our May 2004 and August 2004 equity offerings to reduce indebtedness under bank credit facilities.

Net proceeds from the issuance of limited partner interests were $646.9 million in 2005 compared to $846.1 million in 2004. We issued 23,979,740 common units in 2005 and 39,683,591 common units in 2004. Net proceeds from underwritten equity offerings were $555.5 million during 2005 reflecting the sale of 21,250,000 units and $694.3 million during 2004 reflecting the sale of 34,500,000 units. We used net proceeds from these underwritten offerings to reduce debt, including the temporary repayment of indebtedness under bank credit facilities. Our distribution reinvestment program and related plan generated net proceeds of $69.7 million in 2005 and $111.6 million in 2004. We used net proceeds from these offerings for general partnership purposes. For additional information regarding our equity issuances, please read Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Cash distributions to partners increased from $438.8 million in 2004 to $716.7 million in 2005 primarily due to an increase in common units outstanding and our quarterly cash distribution rates. We expect that future cash distributions to partners will increase as a result of our periodic issuance of common units. Cash contributions from minority interests were $39.1 million in 2005 compared to $9.6 million in

2004. These amounts relate to contributions from our joint venture partner in the Independence Hub project.

Our financing activities for 2004 include a net cash receipt of $19.4 million resulting from the settlement of forward starting interest rate swaps.

Comparison of Year Ended December 31, 2004 with Year Ended December 31, 2003

Operating activities. Net cash provided from operating activities was $391.5 million in 2004 compared to $424.7 million in 2003. The $33.2 million decrease in net cash provided from operating activities is primarily due to (i) net income adjusted for all non-cash items and the net effects of changes in operating accounts decreased $69.3 million year-to-year primarily due to timing of cash receipts from sales and cash payments for purchases and other expenses between periods and (ii) distributions received from unconsolidated affiliates increased $36.1 million year-to-year primarily due to distributions from GulfTerra GP, which we acquired in December 2003.

Investing activities. Cash used in investing activities was $941.4 million in 2004 compared to $662.1 million in 2003. We used $638.8 million in 2004 to complete the GulfTerra Merger, including our purchase of the South Texas midstream assets. Our expenditures for other asset purchases and business combinations were $724.7 million in 2004 versus $37.3 million in 2003. Investments in unconsolidated affiliates were $57.9 million in 2004 compared to $463.9 million in 2003, which includes our $425 million cash payment to El Paso to acquire GulfTerra GP in December 2003. Expenditures for growth and sustaining capital projects (net of contributions in aid of construction costs) were essentially flat year-to-year at approximately $146 million for each period.

Financing activities. Cash provided by financing activities was $544 million in 2004 compared to $254 million in 2003. We had net borrowings of $125.6 million during 2004 compared to net repayments of $106.8 million during 2003. As discussed under *Financing activities* on page 62, net borrowings during 2004 primarily reflect debt transactions associated with the GulfTerra Merger. Our borrowing transactions during 2003 include the issuance of an aggregate $850 million in senior notes and the borrowing of $425 million under a bank credit facility to purchase GulfTerra GP. Repayments of debt during 2003 reflect the use of net proceeds from debt and equity offerings completed in 2003 to reduce indebtedness under bank credit facilities, including the repayment of $1 billion outstanding under a term loan we used to acquire ownership interests in the Mid-America Pipeline System and Seminole Pipeline.

Net proceeds from the issuance of limited partner interests were $846.1 million in 2004 compared to $675.7 million in 2003. We issued 39,683,591 common units in 2004 and 29,506,303 common units in 2003. Net proceeds from underwritten equity offerings were $694.3 million during 2004 reflecting the sale of 34,500,000 units and $519.2 million during 2003 reflecting the sale of 26,622,500 units. We used net proceeds from these underwritten offerings primarily to reduce debt, including the temporary repayment of indebtedness under bank credit facilities. In addition, we received $100 million from the sale of 4,413,549 Class B special units to an affiliate of EPCO in 2003. The Class B special units converted to common units in July 2004.

Our distribution reinvestment program and related plan generated net proceeds of $111.6 million in 2004 and $60.3 million in 2003. We used net proceeds from these offerings for general partnership purposes. The year-to-year increase in net proceeds from our distribution reinvestment program is attributable to EPCO, which publicly announced in 2003 that it would reinvest approximately $140 million of its cash distributions in support of our growth objectives. This commitment extended from the distribution paid in February 2004 to the distribution paid in February 2005.

Cash distributions to partners increased from $309.9 million in 2003 to $438.8 million in 2004 primarily due to an increase in distribution-bearing units outstanding and higher cash distribution rates.

Financing activities include net cash receipts of $19.4 million in 2004 and $5.4 million in 2003 resulting from the settlement of interest rate hedging financial instruments.

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CONTRACTUAL OBLIGATIONS

The following table summarizes our significant contractual obligations at December 31, 2005. A description of each type of contractual obligation follows (dollars in thousands).

		Payment or Settlement due by Period			
Contractual Obligations	**Total**	**Less than 1 year** (2006)	**1-3 years** (2007 2008)	**3-5 years** (2009 2010)	**More than 5 years** Beyond 2010
Scheduled Maturities of Long-Term Debt	$ 4,866,068		$ 517,000	$1,549,068	$2,800,000
Estimated Cash Payments for Interest	$ 3,160,380	$ 271,597	$ 518,809	$ 455,189	$1,914,785
Operating Lease Obligations	$ 179,623	$ 19,099	$ 33,848	$ 20,089	$ 106,587
Purchase Obligations:					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$ 1,518,016	$ 216,690	$ 433,973	$ 433,380	$ 433,973
NGLs	$ 6,095,907	$ 684,250	$1,118,948	$ 999,800	$3,292,909
Petrochemicals	$ 1,290,952	$1,079,110	$ 211,842		
Other	$ 87,162	$ 31,578	$ 44,724	$ 10,860	
Underlying major volume commitments:					
Natural gas (in BBtus)	127,850	18,250	36,550	36,500	36,550
NGLs (in MBbls)	63,130	9,251	12,827	10,172	30,880
Petrochemicals (in MBbls)	19,717	16,525	3,192		
Service payment commitments	$ 5,765	$ 5,037	$ 728		
Capital expenditure commitments	$ 208,575	$ 208,575			
Other Long-Term Liabilities, as reflected on our Consolidated Balance Sheet	$ 84,486		$ 24,828	$ 9,897	$ 49,761
Total	$17,496,934	$2,515,936	$2,904,700	$3,478,283	$8,598,015

Scheduled Maturities of Long-Term Debt

We have long and short-term payment obligations under debt agreements such as the indentures governing our Operating Partnership s senior notes and the credit agreement governing our Operating Partnership s Multi-Year Revolving Credit Facility. Amounts shown in the table represent our scheduled future maturities of long-term debt principal for the periods indicated. For additional information regarding our debt obligations, please read Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Estimated Cash Payments for Interest

We are obligated to make interest payments on our debt principal amounts outstanding. The amounts shown in the preceding table for estimated cash interest payments represent our forecast of variable and fixed interest payments to be made in connection with debt principal amounts outstanding at December 31, 2005. Our estimates of future cash interest payments include the following amounts to be paid in connection with variable interest rates: $146.6 million in total, $31.5 million for 2006, $31.2 million for 2007, $30.8 million for each of 2008 and 2009, and $22.3 million for 2010. We estimated our variable interest rate cash payments by multiplying the weighted-average variable interest rate paid during 2005 (under each of our variable rate debt obligations that were outstanding at December 31, 2005) by the debt principal amount outstanding at that date and assumed that the balance outstanding would not change until maturity.

Our estimates of cash interest payments to be paid under fixed interest rate obligations were determined by multiplying the fixed interest rate associated with each fixed-rate obligation for each period that the principal would be outstanding until maturity. To the extent that we have exchanged a fixed interest rate for a variable interest rate, we have included the impact of such interest rate swap agreements in our calculations. Our internal estimates of long-term interest rates indicate that variable interest rates may exceed the fixed interest rates of the debt obligations underlying our interest rate swap agreements. If this occurs, we are responsible for payment of the excess of the current variable interest rate over the fixed interest rate of the underlying debt obligation. For conservatism, the amounts shown in the table above do not reflect any cash receipts from interest rate swap agreements (i.e. net reductions in cash outlays for interest) when the variable interest rate is less than the fixed interest rate of the underlying debt obligations.

For information regarding our interest rate swap agreements, please read Item 7A of this annual report.

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 third-party operating leases with terms in excess of one year for the periods indicated. For additional information regarding our operating lease commitments, please read Note 21 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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:

Product purchase commitments. We have long and short-term product purchase obligations for NGLs, petrochemicals and natural gas 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, 2005 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery.

Service contract commitments. We have long and short-term commitments to pay third-party providers for services such as maintenance agreements. Our contractual payment obligations vary by contract. The preceding table shows our future payment obligations under these service contracts.

Capital expenditure commitments. We have short-term payment obligations relating to capital projects we have initiated and are also responsible for our share of such obligations associated with the capital projects of our unconsolidated affiliates. These commitments represent unconditional payment obligations that we or our unconsolidated affiliates have agreed to pay vendors for services rendered or products purchased. The preceding table shows these combined amounts for the periods indicated.

Other Long-Term Liabilities

We have recorded long-term liabilities on our balance sheet reflecting amounts we expect to pay in future periods beyond one year. These liabilities primarily relate to reserves for asset retirement obligations, environmental liabilities and other amounts. Amounts shown in the preceding table represent our best estimate as to the timing of payments based on available information.

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OFF-BALANCE SHEET ARRANGEMENTS

Cameron Highway issued senior secured notes in December 2005. We secure a portion of these notes by (i) a pledge by us of our 50% partnership interest in Cameron Highway, (ii) mortgages on and pledges of certain assets related to certain rights of way and pipeline assets of an indirect wholly-owned subsidiary of ours that serves as the operator of the Cameron Highway Oil Pipeline, and (iii) letters of credit in an initial amount of $18.4 million issued by the Operating Partnership on behalf of Cameron Highway. For more information regarding Cameron Highway s senior secured notes, please read Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. In addition, we have furnished $1.2 million in letters of credit on behalf of Evangeline at December 31, 2005. We currently expect that Cameron Highway will seek to amend its senior secured notes during 2006 to address delayed increases in volumes due to disruptions of production caused by Hurricanes Katrina and Rita, but we believe that such amendments will be obtained without any material adverse effect on us.

Except for the foregoing, 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 condition, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources.

RECENT ACCOUNTING DEVELOPMENTS

The following information summarizes recently issued accounting guidance that will (or may) affect our financial statements in the future:

§ SFAS 123(R), *Share-Based Payment*, eliminates the ability to account for share-based compensation transactions using Accounting Principles Board (APB) 25 and generally requires that such transactions be accounted for using a fair value method. Historically, we have accounted for our share-based transactions using APB 25. We adopted SFAS 123(R) on January 1, 2006, which resulted in our recording a cumulative effect of a change in accounting principle of $0.3 million. During 2006, we expect to record compensation expense of $7 million associated with the fair value method of accounting for unit options, profits interests and nonvested (or restricted) units using SFAS 123(R) based on awards outstanding at January 1, 2006.

§ SFAS 154, *Accounting Changes and Error Corrections*, provides guidance on the accounting for and reporting of accounting changes and error corrections. We adopted SFAS 154 on January 1, 2006.

§ Emerging Issues Task Force (EITF) 04-13, *Accounting for Purchases and Sale of Inventory With the Same Counterparty*, requires that two or more inventory transactions with the same counterparty be viewed as a single nonmonetary transaction, if the transactions were entered into in contemplation of one another. Exchanges of inventory between entities in the same line of business should be accounted for at fair value or recorded at carrying amounts, depending on the classification of such inventory. We are still evaluating this recent guidance, which is effective April 1, 2006 for our partnership, but we do not believe that our revenues or costs and expenses will be materially affected.

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CRITICAL ACCOUNTING POLICIES

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 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 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 on a going forward basis. Some of these circumstances include changes in laws and regulations relating to restoration and abandonment requirements; changes in expected costs for dismantlement, restoration and abandonment as a result of changes, or expected changes, in labor, materials and other related costs associated with these activities; changes in the useful life of an asset based on the actual known life of similar assets, changes in technology, or other factors; and changes in expected salvage proceeds as a result of a change, or expected change in the salvage market.

At December 31, 2005 and 2004, the net book value of our property, plant and equipment was $8.7 billion and $7.8 billion, respectively. We recorded $328.7 million, $161 million and $101 million in depreciation expense during 2005, 2004 and 2003, respectively. A significant portion of the year-to-year increase in depreciation expense between 2005 and 2004 is attributable to the property, plant and equipment assets we acquired in the GulfTerra Merger in September 2004. For additional information regarding our property, plant and equipment, please read Notes 2 and 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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, oil or NGLs. Long-lived assets with recorded values that are not expected to be recovered through future expected 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. We recorded $1.2 million and $4.1 million for asset impairment charges in 2003 and 2004, respectively, related to NGL fractionation and storage facilities located in Mississippi.

Equity method investments are evaluated for impairment whenever events or changes in circumstances indicate that there is a possible loss in value for 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. 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.

Due to a deteriorating business environment, BEF evaluated the carrying value of its long-lived assets for impairment during the third quarter of 2003. This review indicated that the carrying value of its long-lived assets exceeded their collective fair value, which resulted in a non-cash impairment charge of $67.5 million. Since BEF was one of our equity investments at that time, our share of this loss was $22.5 million and was recorded as a component of equity earnings from unconsolidated affiliates during 2003.

For additional information regarding our asset impairment charges, please read Notes 2 and 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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 the GulfTerra Merger and related transactions. 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 third-party 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. 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 (i) the expected useful life of the related tangible assets (e.g., fractionation facility, pipeline, etc.), (ii) any legal or regulatory developments that would impact such contractual rights, and (iii) 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, 2005 and 2004, the carrying value of our intangible asset portfolio was $913.6 million and $980.6 million, respectively. We recorded $88.9 million, $33.8 million and $14.8 million in amortization expense associated with our intangible assets during 2005, 2004 and 2003, respectively. A significant portion of the year-to-year increase in amortization expense between 2005 and 2004 is attributable to the intangible assets we acquired in the GulfTerra Merger.

For additional information regarding our intangible assets, please read Notes 2 and 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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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 and is primarily comprised of $387.1 million associated with the GulfTerra Merger. 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 (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management s estimates of operating margins and transportation volumes, (ii) long-term growth rates for cash flows beyond the discrete forecast period, and (iii) 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, 2005 and 2004, the carrying value of our goodwill was $494 million and $459.2 million, respectively.

For additional information regarding our goodwill, please read Notes 2 and 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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: (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) collectibility is reasonably assured. 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.

Our use of certain estimates for revenues and operating costs and other 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 of compiling 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.

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.

At December 31, 2005 and 2004, we had a liability for environmental remediation of $21 million, which was derived from a range of reasonable estimates based upon studies and site surveys. In accordance with SFAS 5 *Accounting for Contingencies* and Financial Accounting Standards Board

Interpretation (FIN) 14, *Reasonable Estimation of the Amount of a Loss*, we recorded our best estimate of these remediation activities.

Natural gas imbalances

Natural gas imbalances result when customers physically deliver a larger or smaller quantity of natural gas into our pipelines than they take out. In general, we value such imbalances using a twelve-month moving average of natural gas prices, which we believe is reasonable given that the actual settlement dates for such imbalances are generally not known. As a result, significant changes in natural gas prices between reporting periods may impact our estimates.

At December 31, 2005 and 2004, our imbalance receivables were $89.4 million and $56.7 million, respectively, and are reflected as a component of accounts receivable. At December 31, 2005 and 2004, our imbalance payables were $80.5 million and $59 million, respectively, and are reflected as a component of accrued gas payables.

SUMMARY OF RELATED PARTY TRANSACTIONS

In accordance with SFAS 57, *Related Party Disclosures*, we have identified our material related party revenues and costs and expenses. The following table summarizes our related party transactions for the periods indicated (dollars in thousands).

	For Year Ended December 31,		
	2005	**2004**	**2003**
Revenues from consolidated operations			
EPCO and affiliates	$ 311	$ 2,697	$ 4,241
Shell		542,912	293,109
Unconsolidated affiliates	354,461	258,541	266,894
Total	$354,772	$804,150	$564,244
Operating costs and expenses			
EPCO and affiliates	$293,134	$203,100	$149,915
Shell		725,420	607,277
Unconsolidated affiliates	23,563	37,587	43,752
Total	$316,697	$966,107	$800,944
General and administrative expenses			
EPCO and affiliates	$ 40,954	$ 29,307	$ 28,716

For additional information regarding our related party transactions identified in accordance with GAAP, please read Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. For information regarding certain business relationships and related transactions, please read Item 13 of this annual report.

We have an extensive and ongoing relationship with EPCO and its affiliates, including TEPPCO. Our revenues from EPCO and affiliates are primarily associated with sales of NGL products. Our expenses with EPCO are primarily due to (i) reimbursements we pay EPCO in connection with an administrative services agreement and (ii) purchases of NGL products. TEPPCO is an affiliate of ours due to the common control relationship of both entities.

Historically, Shell was considered a related party under GAAP because it owned more than 10% of our limited partner interests and, prior to 2003, held a 30% membership interest in Enterprise Products GP. As a result of Shell selling a portion of its limited partner interests in us to third parties and our issuance of additional common units, Shell owned less than 10% of our common units at the beginning of 2005. Shell sold its 30% interest in Enterprise Products

GP to an affiliate of EPCO in September 2003. As a result of Shell s reduced equity interest in us and its lack of control of Enterprise Products GP, Shell ceased to be considered a related party under GAAP in January 2005.

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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 to Promix for NGL transportation, storage and fractionation services.

OTHER ITEMS

Non-GAAP reconciliation

A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles follows (dollars in thousands):

	Year Ended December 31,		
	2005	**2004**	**2003**
Total non-GAAP gross operating margin	$1,136,347	$ 655,191	$ 410,415
Adjustments to reconcile total non-GAAP gross operating margin to GAAP operating income:			
Depreciation and amortization in operating costs and expenses	(413,441)	(193,734)	(115,643)
Retained lease expense, net in operating costs and expenses	(2,112)	(7,705)	(9,094)
Gain on sale of assets in operating costs and expenses	4,488	15,901	16
General and administrative costs	(62,266)	(46,659)	(37,590)
GAAP consolidated operating income	663,016	422,994	248,104
Other net expense, primarily interest expense	(225,178)	(153,625)	(134,406)
GAAP income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 437,838	$ 269,369	$ 113,698

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year (the retained leases). These subleases are part of the administrative services agreement 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 partners 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. For additional information regarding the administrative services agreement and the retained leases, please read Item 13 of this annual report.

Cumulative effect of changes in accounting principles

Our Consolidated Statements of Operations and Comprehensive Income reflect the following cumulative effects of changes in accounting principles:

§ We recorded a $4.2 million non-cash expense related to certain asset retirement obligations in 2005 due to our implementation of FIN 47 as of December 31, 2005.

§ We recorded a combined $10.8 million non-cash gain in 2004 related to the impact of (i) changing the method our BEF subsidiary uses to account for its planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method and (ii) changing the method in which we account for our investment in VESCO from the cost method to the equity method.

For additional information regarding these changes in accounting principles, including a presentation of the pro forma effects these changes would have had on our historical earnings, please read Note 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Financial statement reclassifications

Certain reclassifications have been made to the prior year s financial statements to conform to the current year presentation. During 2005, we changed the classification of changes in restricted cash in our Statements of Consolidated Cash Flows to present such changes as an investing activity. We previously presented such changes as an operating activity. In the accompanying Statements of Consolidated Cash Flows for the years ended December 31, 2004 and 2003, we reclassified the change in restricted cash to be consistent with our 2005 presentation. This reclassification resulted in a $12.3 million and $5.1 million increase to cash flows used in investing activities and a corresponding increase to cash provided by operating activities from the amounts previously presented for the years ended December 31, 2004 and 2003, respectively.

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

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

We recognize financial instruments as assets and liabilities on our Consolidated Balance Sheets based on fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument s gains and losses offset the related results of the hedged item in earnings for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses related to a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings. For additional information regarding our accounting for financial instruments, please read Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

To qualify as a hedge, the item to be hedged must be exposed to commodity or interest rate risk and the 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 must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness of the hedge is recorded in current earnings.

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

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess cash flow risk related to interest rates by identifying and measuring changes in our interest rate exposures that may impact future cash flows and evaluating hedging opportunities to manage these risks. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis models to forecast the expected impact of changes in interest rates on our future cash flows. Enterprise Products GP oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

We manage a portion of our interest rate exposures 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. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt in the current business environment.

As summarized in the following table, we had eleven interest rate swap agreements outstanding at December 31, 2005 that were accounted for as fair value hedges.

Hedged Fixed Rate Debt	Number Of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Amount
Senior Notes B, 7.50% fixed rate, due Feb. 2011	1	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 7.26%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.8%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 5.24%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 4.99%	$200 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.

These eleven agreements have a combined notional amount of $1.1 billion and match the maturity dates of the underlying debt being hedged. Under each swap agreement, we pay the counterparty a variable interest rate based on six-month London interbank offered rate (LIBOR) (plus an applicable margin as defined in each swap agreement), and receive back from the counterparty a fixed interest rate payment based on the stated interest rate of the debt being hedged, with both payments calculated using the notional amounts stated in each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the settlement period). The settlement amount is amortized ratably to earnings as either an increase or a decrease in interest expense over the settlement period.

The total fair value of these eleven interest rate swaps at December 31, 2005, was a liability of $19.2 million, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the years ended December 31, 2005 and 2004 reflects a $10.8 million and $9.1 million benefit from these swap agreements, respectively.

The following tables show 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 thousands). Income is not affected by changes in the fair value of these swaps; however, these swaps effectively convert the hedged portion of fixed-rate debt to variable-rate debt. As a result, interest expense (and related cash outlays for debt service) will increase or decrease with the change in the periodic reset rate associated with the respective swap. Typically, the reset rate is an agreed upon index rate published for the first day of the six-month interest calculation period.

	Resulting	Swap Fair Value at

Scenario	Classification	December 31, 2004	December 31, 2005	February 1, 2006
FV assuming no change in underlying interest rates	*Asset (Liability)*	$ 505	$ (19,179)	$ (28,621)
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(31,586)	(50,308)	(59,744)
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	32,596	11,950	2,503

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The fair value of the interest rate swaps excludes the benefit we have already recorded in earnings. The change in fair value between December 31, 2005 and February 1, 2006 is primarily due to an increase in market interest rates relative to the forward interest rate curve used to determine the fair value of our financial instruments. The underlying floating LIBOR forward interest rate curve used to determine the February 1, 2006 fair values ranged from approximately 4.3% to 5.2% using 6-month reset periods ranging from October 2005 to October 2014.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and 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 risks associated with natural gas and NGLs, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to hedge our exposure to price risks associated with (i) natural gas purchases, (ii) NGL 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 or NGLs. The commodity financial instruments we utilize may be settled in cash or with another financial instrument. Historically, we have not hedged our exposure to risks associated with petrochemical products.

We have adopted a policy to govern our use of commodity financial instruments to manage the risks of our natural gas and NGL businesses. The objective of this policy is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by Enterprise Products GP. We may enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 24 months. Enterprise Products GP oversees the strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

At December 31, 2005, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of economic hedges. The fair value of our commodity financial instrument portfolio at December 31, 2005 was a liability of $0.1 million. We recorded nominal amounts of earnings from our commodity financial instruments during 2005, 2004 and 2003.

Product Purchase Commitments

We have long and short-term purchase commitments for NGLs, petrochemicals and natural gas 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, please read *Contractual Obligations* included under Item 7 of this annual report.

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Item 8. ***Financial Statements and Supplementary Data.***

ENTERPRISE PRODUCTS PARTNERS L.P.
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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 consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the Company) as of December 31, 2005 and 2004, and the related consolidated statements of consolidated operations and comprehensive income, consolidated cash flows and consolidated partners equity for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedule in Item 15. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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 consolidated financial statements present fairly, in all material respects, the financial position of Enterprise Products Partners L.P. and subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2005, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2006 expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 27, 2006

ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2005	December 31, 2004
ASSETS		
Current assets		
Cash and cash equivalents	$ 42,098	$ 24,556
Restricted cash	14,952	26,157
Accounts and notes receivable trade, net of allowance for doubtful accounts of $25,849 at December 31, 2005 and $24,310 at December 31, 2004	1,448,026	1,058,375
Accounts receivable related parties	6,557	25,161
Inventories	339,606	189,019
Prepaid and other current assets	120,208	80,893
Assets held for sale		36,562
Total current assets	1,971,447	1,440,723
Property, plant and equipment, net	8,689,024	7,831,467
Investments in and advances to unconsolidated affiliates	471,921	519,164
Intangible assets, net of accumulated amortization of $163,121 at December 31, 2005 and $74,183 at December 31, 2004	913,626	980,601
Goodwill	494,033	459,198
Deferred tax asset	3,606	6,467
Other assets	47,359	77,841
Total assets	$12,591,016	$11,315,461
LIABILITIES AND PARTNERS EQUITY		
Current liabilities		
Current maturities of debt		$ 15,000
Accounts payable trade	$ 265,699	203,142
Accounts payable related parties	23,367	41,293
Accrued gas payables	1,372,837	1,021,294
Accrued expenses	30,294	130,051
Accrued interest	71,193	70,335
Other current liabilities	126,881	104,764
Total current liabilities	1,890,271	1,585,879
Long-term debt	4,833,781	4,266,236
Other long-term liabilities	84,486	63,521
Minority interest	103,169	71,040
Commitments and contingencies		
Partners equity		

Limited Partners		
Common units (389,109,564 units outstanding at December 31, 2005 and 364,297,340 units outstanding at December 31, 2004)	5,542,700	5,204,940
Restricted common units (751,604 units outstanding at December 31, 2005 and 488,525 units outstanding at December 31, 2004)	18,638	12,327
Treasury units, at cost (427,200 units outstanding at December 31, 2004)		(8,660)
General partner	113,496	106,475
Accumulated other comprehensive income	19,072	24,554
Deferred compensation	(14,597)	(10,851)
Total partners equity	5,679,309	5,328,785
Total liabilities and partners equity	$12,591,016	$11,315,461

See Notes to Consolidated Financial Statements

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ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
AND COMPREHENSIVE INCOME
(Dollars in thousands, except per unit amounts)

	For Year Ended December 31,		
	2005	**2004**	**2003**
REVENUES			
Third parties	$11,902,187	$7,517,052	$4,782,187
Related parties	354,772	804,150	564,244
Total	12,256,959	8,321,202	5,346,431
COST AND EXPENSES			
Operating costs and expenses			
Third parties	11,229,528	6,938,229	4,245,833
Related parties	316,697	966,107	800,944
Total operating costs and expenses	11,546,225	7,904,336	5,046,777
General and administrative costs			
Third parties	21,312	17,352	8,874
Related parties	40,954	29,307	28,716
Total general and administrative costs	62,266	46,659	37,590
Total costs and expenses	11,608,491	7,950,995	5,084,367
EQUITY IN INCOME (LOSS) OF UNCONSOLIDATED AFFILIATES	14,548	52,787	(13,960)
OPERATING INCOME	663,016	422,994	248,104
OTHER INCOME (EXPENSE)			
Interest expense	(230,549)	(155,740)	(140,806)
Dividend income from unconsolidated affiliates			5,595
Other, net	5,371	2,115	805
Other expense	(225,178)	(153,625)	(134,406)
INCOME BEFORE PROVISION FOR INCOME TAXES, MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES	437,838	269,369	113,698
Provision for income taxes	(8,362)	(3,761)	(5,293)
INCOME BEFORE MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES	429,476	265,608	108,405
Minority interest	(5,760)	(8,128)	(3,859)

INCOME BEFORE CHANGES IN ACCOUNTING PRINCIPLES	423,716	257,480	104,546
Cumulative effect of changes in accounting principles (see Note 8)	(4,208)	10,781	
NET INCOME	$ 419,508	$ 268,261	$ 104,546
Cash flow financing hedges		19,405	5,354
Amortization of cash flow financing hedges	(4,048)	(1,275)	3,196
Change in fair value of commodity hedges	(1,434)	1,434	
COMPREHENSIVE INCOME	$ 414,026	$ 287,825	$ 113,096
ALLOCATION OF NET INCOME TO: (see Note 16)			
Limited partners interest in net income	$ 348,512	$ 231,153	$ 83,817
General partner interest in net income	$ 70,996	$ 37,108	$ 20,729
EARNING PER UNIT: (see Note 20)			
Basic income per unit before changes in accounting principles	$ 0.92	$ 0.83	$ 0.42
Basic income per unit	$ 0.91	$ 0.87	$ 0.42
Diluted income per unit before changes in accounting principles	$ 0.92	$ 0.83	$ 0.41
Diluted income per unit	$ 0.91	$ 0.87	$ 0.41

See Notes to Consolidated Financial Statements

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ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For Year Ended December 31, 2005	2004	2003
OPERATING ACTIVITIES			
Net income	$ 419,508	$ 268,261	$ 104,546
Adjustments to reconcile net income to cash flows provided by operating activities:			
Depreciation and amortization in operating costs and expenses	413,441	193,734	115,642
Depreciation and amortization in general and administrative costs	7,184	1,650	159
Amortization in interest expense	152	3,503	12,634
Equity in (income) loss of unconsolidated affiliates	(14,548)	(52,787)	13,960
Distributions received from unconsolidated affiliates	56,058	68,027	31,882
Provision for impairment of long-lived asset		4,114	1,200
Cumulative effect of changes in accounting principles	4,208	(10,781)	
Operating lease expense paid by EPCO, Inc.	2,112	7,705	9,010
Other expenses paid by EPCO, Inc.			436
Minority interest	5,760	8,128	3,859
Gain on sale of assets	(4,488)	(15,901)	(16)
Deferred income tax expense	8,594	9,608	10,534
Changes in fair market value of financial instruments	122	5	(29)
Net effect of changes in operating accounts (see Note 23)	(266,395)	(93,725)	120,888
Net cash provided from operating activities	631,708	391,541	424,705
INVESTING ACTIVITIES			
Capital expenditures	(864,453)	(155,793)	(146,790)
Contributions in aid of construction costs	47,004	8,865	877
Proceeds from sale of assets	44,746	6,882	212
Decrease (increase) in restricted cash	11,204	(12,305)	(5,100)
Cash used for business combinations and asset purchases (see Note 12)	(326,602)	(724,661)	(37,348)
Acquisition of intangible asset	(1,750)		(2,000)
Investments in unconsolidated affiliates	(87,342)	(57,948)	(463,876)
Advances to unconsolidated affiliates	(702)	(6,464)	(8,051)
Return of investment from unconsolidated affiliate	47,500		
Cash used in investing activities	(1,130,395)	(941,424)	(662,076)
FINANCING ACTIVITIES			
Borrowings under debt agreements	4,192,345	5,934,505	1,926,210
Repayments of debt	(3,630,611)	(5,808,877)	(2,033,000)
Debt issuance costs	(9,297)	(19,911)	(8,833)

Distributions paid to partners	(716,699)	(438,765)	(309,918)
Distributions paid to minority interests	(5,724)	(6,440)	(8,113)
Contributions from minority interests	39,110	9,585	5,949
Contributions from general partner related to issuance of restricted units	177		
Net proceeds from issuance of common units	646,928	846,077	573,684
Net proceeds from issuance of Class B special units			102,041
Treasury units reissued		8,394	646
Settlement of cash flow financing hedges		19,405	5,354
Cash provided by financing activities	516,229	543,973	254,020
NET CHANGE IN CASH AND CASH EQUIVALENTS	17,542	(5,910)	16,649
CASH AND CASH EQUIVALENTS, JANUARY 1	24,556	30,466	13,817
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 42,098	$ 24,556	$ 30,466

See Notes to Consolidated Financial Statements

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ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED PARTNERS EQUITY
(See Note 15 for Unit History and Detail of Changes in Limited Partners Equity)
(Dollars in thousands)

	Limited Partners	General Partner	Treasury units	Deferred Compensation	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2002	$1,210,049	$ 12,223	$(17,808)		$ (3,560)	$1,200,904
Net income	83,817	20,729				104,546
Operating leases paid by EPCO, Inc.	8,913	97				9,010
Other expenses paid by EPCO, Inc.	433	3				436
Cash distributions to partners	(284,593)	(22,574)				(307,167)
Unit option reimbursements to EPCO, Inc.	(2,721)	(30)				(2,751)
Net proceeds from sales of common units	567,945	5,739				573,684
Proceeds from issuance of Class B special units	100,000	2,041				102,041
Restructuring of Enterprise Products GP ownership in our Operating Partnership	(73)	16,127				16,054
Treasury unit transactions:						
- Reissued to satisfy unit options	6		640			646
- Retired	(643)	(6)	649			
Treasury lock financial instruments recorded as cash flow hedges:						
- Reclassification of change in fair value					3,560	3,560
- Cash gains on settlement					5,354	5,354
- Amortization of gain as component of interest expense					(364)	(364)
	1,683,133	34,349	(16,519)		4,990	1,705,953

Balance, December 31, 2003						
Net income	231,153	37,108				268,261
Operating leases paid by EPCO, Inc.	7,551	154				7,705
Cash distributions to partners	(394,434)	(40,440)				(434,874)
Unit option reimbursements to EPCO, Inc.	(3,813)	(78)				(3,891)
Net proceeds from sales of common units	789,758	16,117				805,875
Proceeds from conversion of Series F2 convertible units to common units	38,800	792				39,592
Proceeds from exercise of unit options	398	8				406
Value of equity interests granted to complete GulfTerra Merger	2,854,275	58,252		$ (1,755)		2,910,772
Other issuance of restricted units	9,922	202		(9,922)		202
Amortization of deferred compensation				826		826
Treasury units issued to satisfy unit options	524	11	7,859			8,394
Change in fair value of commodity hedges					1,434	1,434
Interest rate hedging financial instruments recorded as cash flow hedges:						
- Cash gains on settlement					19,405	19,405
- Amortization of gain as component of interest expense					(1,275)	(1,275)
Balance, December 31, 2004	5,217,267	106,475	(8,660)	(10,851)	24,554	5,328,785
Net income	348,512	70,996				419,508
Operating leases paid by EPCO, Inc.	2,070	42				2,112
Cash distributions to partners	(630,560)	(76,752)				(707,312)
Unit option reimbursements to EPCO, Inc.	(9,199)	(188)				(9,387)

Net proceeds from sales of common units	612,616	12,502				625,118
Proceeds from exercise of unit options	21,374	436				21,810
Issuance of restricted units	9,478	177		(9,480)		175
Forfeiture of restricted units	(2,663)	(38)		2,361		(340)
Amortization of Employee Partnership awards	1,358	28				1,386
Amortization of deferred compensation				3,373		3,373
Cancellation of treasury units	(8,915)	(182)	8,660			(437)
Change in fair value of commodity hedges					(1,434)	(1,434)
Interest rate hedging financial instruments recorded as cash flow hedges:						
- Amortization of gain as component of interest expense					(4,048)	(4,048)
Balance, December 31, 2005	$5,561,338	$113,496	$	$(14,597)	$ 19,072	$5,679,309

See Notes to Consolidated Financial Statements

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ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. 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 consolidated business and operations of Enterprise Products Partners L.P. and its subsidiaries.

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 L.P. (our Operating Partnership). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as Enterprise Products GP). Enterprise Products GP is owned 100% by Enterprise GP Holdings L.P. (Enterprise GP Holdings), a publicly traded affiliate, the common 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 EPCO. We, Enterprise Products GP, Enterprise GP Holdings and EPE Holdings are affiliates and under common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO.

In September 2004, we completed the GulfTerra Merger transactions, whereby, among other transactions, GulfTerra Energy Partners L.P. (GulfTerra) merged with one of our wholly owned subsidiaries. As a result of the GulfTerra Merger, GulfTerra and its subsidiaries and GulfTerra s general partner (GulfTerra GP) became our wholly owned subsidiaries. The GulfTerra Merger greatly expanded our asset base to include numerous natural gas and crude oil pipelines, offshore platforms and other midstream energy assets. Additionally, the GulfTerra Merger included the purchase of various midstream assets from El Paso Corporation (El Paso) that are located in South Texas (the STMA acquisition).

2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts amount is generally determined based on specific identification and estimates of future uncollectible accounts. Our procedure for recording an allowance for doubtful accounts is based on (i) our historical experience, (ii) the financial stability of our customers and (iii) the levels of credit granted to customers. In addition, we may also increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and those experiencing other financial difficulties. We routinely review our estimates in this area to ascertain that we have recorded sufficient reserves to cover potential losses. Our allowance for doubtful accounts was $25.8 million and $24.3 million at December 31, 2005 and 2004, respectively.

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 Statements of Consolidated Cash Flows are prepared using the indirect method.

Consolidation Policy

Our 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 consolidate majority-owned subsidiaries in which we possess a controlling financial interest through a direct or indirect ownership of a majority voting interest in the subsidiary.

Investments in which we own 3% to 50% and exercise significant influence over operating and financial policies are accounted for using the equity method. If the investee is organized as a limited liability company and maintains separate ownership accounts for its members, we account for our investment using the equity method if our ownership interest is between 3% and 50%. For all other types of investees, we apply the equity method of accounting if our ownership interest is between 20% and 50%. Our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates are eliminated in consolidation to the extent such amounts are material and remain on our or our equity method investees balance sheet in inventory or similar accounts.

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

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to Enterprise Products Partners but which will only be resolved when one or more future events occur or fail to occur. Our management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our legal counsel evaluates the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss if determinable and material, is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

Deferred Revenues

We recognize revenues when earned. Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. Please see Note 4 for additional discussion of revenues.

Dollar Amounts

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

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 20 for our computation of earnings per unit for 2005, 2004 and 2003.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management s estimate of the ultimate cost to remediate the site. Ongoing environmental compliance costs are charged to expense as incurred. Expenditures to mitigate or prevent future environmental contamination are capitalized.

Environmental costs and related accruals were not significant prior to the GulfTerra Merger. As a result of the merger, we assumed an environmental liability estimated at $21 million for remediation costs associated with mercury gas meters. This estimate is included in other long-term liabilities on our Consolidated Balance Sheets at December 31, 2005 and 2004.

Costs of environmental compliance and monitoring aggregated $3.3 million, $1.9 million and $1.6 million during 2005, 2004 and 2003, respectively.

Equity Awards

Beginning January 1, 2006, we will account for our equity awards using the provisions of Statement of Financial Standards (SFAS) 123(R), *Share-Based Payment.* Historically, our equity awards were accounted for using the intrinsic value method described in Accounting Principles Board Opinion (APB) 25, *Accounting for Stock Issued to Employees.* SFAS 123(R) requires us to recognize compensation expense related to our equity awards based on the fair value of the award at the grant date. The fair value of an equity award will be determined using option pricing models (Black-Scholes or Binomial models). Under SFAS 123(R), the fair value of an award will be amortized to earnings on a straight-line basis over the requisite service or vesting period. Previously recognized deferred compensation related to nonvested units will be reversed on January 1, 2006. See Note 5 for additional information regarding our equity awards.

Unit options. Under APB 25, we did not recognize any compensation expense related to unit options when the exercise price was equal to or greater than the market price of the underlying equity on the date of grant. Based on information currently available, we estimate that our compensation expense related to unit options will be $0.6 million in 2006 using the provisions of SFAS 123(R).

Profits Interests. In connection with the initial public offering of Enterprise GP Holdings in August 2005, EPE Unit L.P. (the Employee Partnership) was formed to allow certain employees of EPCO to increase their ownership in Enterprise GP Holdings and to serve as an incentive arrangement for such employees through a profits interest in the Employee Partnership. During 2005, the value of the profits interests was accounted for similar to a stock appreciation right. Based on information currently available, we estimate that our share of compensation expense related to the profits interests will be $2.2 million in 2006 using the provisions of SFAS 123(R). Using a Black-Scholes model, EPCO estimated the grant date fair value of the Class B partnership interests to be $12.5 million. For additional information regarding the Employee Partnership, see *Relationship with EPCO and affiliates* under Note 18.

Nonvested Units. We issued nonvested (or restricted) units to key employees of EPCO during 2005 and 2004. In general, our nonvested common units are classified as either time-vested or performance-based. Historically, unearned compensation, representing the fair market value of such nonvested units at the date of issuance, was charged to earnings as compensation expense on a straight-line basis over the vesting period. Prior to 2006, we recognized forfeitures of nonvested units as they occurred. As a result of SFAS 123(R), we will estimate such forfeitures at grant date. Based on information currently available, we estimate that our compensation expense related to nonvested units will be $4.2 million in 2006 using the provisions of SFAS 123(R).

Pro forma disclosures under SFAS 123. In accordance with SFAS 148, *Accounting for Stock-Based Compensation Transition and Disclosure,* we disclose the pro forma effect on our earnings as if the fair value method of SFAS 123, *Accounting for Stock-Based Compensation* had been used instead of the intrinsic-value method of APB 25 to account for our equity awards. The effects of applying SFAS 123 in the following pro forma disclosure may not be indicative of future amounts as additional awards in future years are anticipated. No pro forma adjustment is required for our nonvested units since compensation expense was recognized in 2005 and 2004 based on estimated fair values of the awards.

The fair value of each unit option is estimated on the date of grant using the Black-Scholes option pricing model and various assumptions. For those unit options granted during 2005, we used the

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following assumptions: (i) expected life of options of seven years; (ii) risk-free interest rate of 4.2%, (iii) expected dividend yield on our units of 9.2% and (iv) expected unit price volatility of 20%.

The fair value of the Class B partnership equity awards was also estimated on the date of grant using the Black-Scholes option pricing model and various assumptions. We used the following assumptions to estimate the fair value of these equity awards: (i) expected life of award of five years; (ii) risk-free interest rate of 4.1%; (iii) expected dividend yield on units of Enterprise GP Holdings of 3% and (iv) expected Enterprise GP Holdings unit price volatility of 30%.

The following table shows the pro forma effects for the periods indicated.

	For Year Ended December 31,		
	2005	**2004**	**2003**
Reported net income	$419,508	$268,261	$104,546
Additional unit option-based compensation expense estimated using fair value-based method	(708)	(932)	(1,107)
Reduction in compensation expense related to Employee Partnership equity awards	1,271		
Pro forma net income	$420,071	$267,329	$103,439
Basic earnings per unit:			
As reported	$ 0.91	$ 0.87	$ 0.42
Pro forma	$ 0.91	$ 0.87	$ 0.41
Diluted earnings per unit:			
As reported	$ 0.91	$ 0.87	$ 0.41
Pro forma	$ 0.91	$ 0.87	$ 0.40

Estimates

Preparing Enterprise Products Partners financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Our actual results could differ from these estimates.

Exchange Contracts

Exchanges are contractual agreements for the movements of NGL and petrochemical products between parties to satisfy timing and logistical needs of the parties. Net exchange volumes borrowed from us under such agreements are valued and included in accounts receivable, and net exchange volumes loaned to us under such agreements are valued and accrued as a liability in accrued gas payables.

Receivables and payables arising from exchange transactions are satisfied with products rather than cash. When monetary consideration is required for product differentials and service costs such items are recognized on a net basis.

Exit and Disposal Costs

Exit and disposal costs are charges associated with an exit activity not associated with 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.

Financial Instruments

We use financial instruments such as swaps, forward and other contracts to manage price risks associated with inventories, firm commitments, interest rates and certain anticipated transactions. We recognize our transactions on the balance sheet as assets and liabilities based on the instrument s fair value. Fair value is generally defined as the amount at which the financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. Changes in fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instrument meets the criteria of a fair value hedge, gains and losses from the instrument will be recorded on the income statement to offset corresponding losses and gains of the hedged item. If the financial instrument meets the criteria of a cash flow hedge, gains and losses from the instrument are recorded in other comprehensive income. Gains and losses on cash flow hedges are reclassified from other comprehensive income to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the underlying asset. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify as a hedge, the item to be hedged must expose us to commodity or interest rate risk and the 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 financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness is immediately recognized in earnings. See Note 7 for a further discussion of our financial instruments.

Impairment Testing for Goodwill

Our goodwill amounts are assessed for recoverability (i) on an annual basis during the second quarter of each year or (ii) on an interim basis when impairment indicators are present. If such indicators are present (e.g., loss of a significant customer, economic obsolescence of plant assets, etc.), the fair value of the reporting unit to which the goodwill is assigned will be calculated and compared to its book value.

If the fair value of the reporting unit exceeds its book value, the goodwill amount is not considered to be impaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value, a charge to earnings is recorded to adjust the carrying value of the goodwill to its implied fair value. We have not recognized any impairment losses related to our goodwill for any of the periods presented. See Note 13 for a further discussion of 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 whenever 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 carrying value exceeds the sum of the undiscounted cash flows, a non-cash asset impairment charge is recognized equal to the excess of the asset s carrying value over its fair value. 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 prices or, in the absence of such data, appropriate valuation techniques.

We recognized non-cash asset impairment charges of $4.1 million and $1.2 million in 2004 and 2003, respectively, which are reflected as components of operating costs and expenses. No asset impairment charges were recorded in 2005.

Impairment Testing for Unconsolidated Affiliates

We evaluate equity method investments (which include excess cost amounts attributable to tangible or intangible assets) for impairment whenever events or changes in circumstances indicate that there is a loss in value of the investment which is an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the investee or long-term negative changes in the investee s industry. In the event that we determine that the loss in value of an investment is other than a temporary decline, we would record a charge to earnings to adjust the carrying value to fair value.

We had no such impairment charges during 2005 or 2004; however, a former unconsolidated affiliate recorded a $67.5 million asset impairment charge during 2003. Our share of this charge was $22.5 million, which was recorded as a reduction in equity earnings from this investee during 2003. See Note 11 for additional information regarding this non-cash charge.

Income taxes

Our limited partnership structure is not subject to federal income taxes. As a result, our earnings or losses for federal income tax purposes are included in the tax returns of our individual partners. We are organized as a pass-through entity for federal income tax purposes. As a result, our partners are individually responsible for the federal income tax on their allocable share of our taxable income. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each unitholder s tax attributes in us.

Provision for income taxes is primarily applicable to certain federal and state tax obligations related to our Seminole Pipeline and Dixie Pipeline. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. See Note 19 for additional information regarding our provision of income taxes.

Inventories

Our inventories primarily consist of NGL, petrochemical and natural gas volumes and 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 (i) purchase from third parties or (ii) 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 (which includes freight-in charges which 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 a further discussion of our inventories.

Costs and expenses, as shown on our Statements of Consolidated Operations and Comprehensive Income, include cost of sales related to inventories. Our consolidated cost of sales amounts were $10.3 billion, $7.2 billion and $4.5 billion during 2005, 2004 and 2003, respectively.

Minority Interest

Minority interest represents third-party ownership interests in the net assets of our subsidiaries that are joint ventures. For financial reporting purposes, the assets and liabilities of our majority owned subsidiaries are consolidated with those of our own, with any third party investor s interest in our consolidated balance amounts shown as minority interest. Minority interest expense reflects the allocation of joint venture earnings to third party investors. Distributions to and contributions from minority interests represent cash payments and cash contributions, respectively, from such third-party investors.

At December 31, 2005, our joint venture subsidiaries were Seminole Pipeline Company (Seminole), Tri-States Pipeline LLC (Tri-States), Independence Hub, LLC (Independence Hub), Dixie Pipeline Company (Dixie) and Belle Rose NGL Pipeline LLC (Belle Rose). At December 31, 2004, our joint venture subsidiaries included those listed for 2005 and Mapletree, LLC and E-Oaktree, LLC. We purchased the remaining 2% membership interests in Mapletree, LLC and E-Oaktree, LLC in June 2005 for $25 million. This acquisition increased our indirect ownership interests in the Mid-America Pipeline System to 100% and the Seminole Pipeline to 90%.

Natural Gas Imbalances

Natural gas imbalances result when a customer injects more or less gas into a pipeline than they withdraw. In general, we value our imbalance receivables and payables using a twelve-month moving average of natural gas prices. We believe this valuation method is appropriate given that actual settlement dates may vary by customer. Changes in natural gas prices may impact our estimates. Prior to the GulfTerra Merger, natural gas imbalances were not significant.

At December 31, 2005 and 2004, our imbalance receivables were $89.4 million and $56.7 million, respectively, and are reflected as a component of Accounts receivable trade on our Consolidated Balance Sheets. At December 31, 2005 and 2004, our imbalance payables were $80.5 million and $59 million, respectively, and are reflected as a component of Accrued gas payables on our Consolidated Balance Sheets.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for major additions and improvements are capitalized and minor replacements, maintenance, and repairs are charged to expense as incurred. When property and equipment are retired or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in the results of operations from the respective period. Depreciation is recorded over the estimated useful lives of the related assets primarily using the straight-line method for financial statement purposes. We use other depreciation methods (generally accelerated) for tax purposes where appropriate. See Note 10 for additional information regarding our property, plant and equipment.

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.

Asset retirement obligations (AROs) are legal obligations associated with the retirement of tangible long-lived assets that result from its acquisition, construction, development and/or normal operation. We record a liability for AROs when incurred and capitalize an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over its useful life. We will either settle our ARO obligations at the recorded amount or incur a gain or loss upon settlement.

Reclassifications

Certain reclassifications have been made to the financial statements of prior years to conform to the current year presentation. These reclassifications had no effect on reported results of operations or financial position for 2004 and 2003.

In 2005, we reclassified changes in restricted cash balances (as shown on our Statements of Cash Flows) from operating activities to investing activities in response to best accounting practices. In order to conform the Statements of Cash Flows for 2004 and 2003 to the current period presentation, we reclassified the $12.3 million and $5.1 million increases in restricted cash balances during 2004 and 2003, respectively, from operating activities to investing activities.

Restricted Cash

Restricted cash represents amounts held by a brokerage firm in connection with (i) our commodity financial instruments portfolio and (ii) physical natural gas purchases made on the NYMEX exchange.

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 start-up costs. Organization costs include legal fees, promotional costs and similar charges incurred in connection with the formation of a business.

3. Recent Accounting Developments

The following information summarizes recently issued accounting guidance that will (or may) affect our financial statements in the future:

§ SFAS 123(R), *Share-Based Payment*, eliminates the ability to account for share-based compensation transactions using APB 25 and generally requires instead that such transactions be accounted for using a fair value method. Historically, we have accounted for our share-based transactions using APB 25. We adopted SFAS 123(R) on January 1, 2006, which resulted in our recording a cumulative effect of a change in accounting principle of $0.3 million. During 2006, we expect to record compensation expense of $7 million associated with the fair value method of accounting for unit options, profits interests and nonvested (or restricted) units using SFAS 123(R) based on awards outstanding at January 1, 2006.

§ SFAS 154, *Accounting Changes and Error Corrections*, provides guidance on the accounting for and reporting of accounting changes and error corrections. We adopted SFAS 154 on January 1, 2006.

§ Emerging Issues Task Force (EITF) 04-13, *Accounting for Purchases and Sale of Inventory With the Same Counterparty*, requires that two or more inventory transactions with the same counterparty should be viewed as a single nonmonetary transaction, if the transactions were entered into in contemplation of one another. Exchanges of inventory between entities in the same line of business should be accounted for at fair value or recorded at carrying amounts, depending on the classification of such inventory. We are still evaluating this recent guidance, which is effective April 1, 2006 for our partnership, but we do not believe that our revenues or costs and expenses will be materially affected.

4. Revenue Recognition

We recognize revenue using the following criteria: (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) collectibility is reasonably assured. We generally do not take title to products gathered, transported or processed unless noted below. The following information summarizes our revenue recognition policies by business segment:

NGL Pipelines & Services

In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, percent-of-proceeds, fee-based contracts, hybrid contracts (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. 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 producer s sale of the mixed NGLs we extract on their behalf. Revenue is recognized under percent-of-proceeds arrangements when the extracted NGLs are delivered and sold to customers. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue in the period the services are provided.

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. 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, revenue is recognized when volumes have been delivered to customers. Revenue from these contracts is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC.

Under our NGL and related product storage contracts, we collect a fee based on the number of days a customer has volumes in storage multiplied by a storage rate for each product. Under these contracts, revenue is recognized ratably over the length of the storage period based on the storage fees specified in each contract.

Revenues from product terminalling contracts (applicable to our import and export operations) are recorded in the period services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded. In our export operations, we may also record revenues related to demand fees we charge customers who reserve to use our export facilities and later fail to do so. We recognize such demand fee revenue when the customer fails to utilize our facilities as required by contract.

In our NGL fractionation business, we enter into fee-based arrangements and percent-of-liquids contracts. Under our fee-based arrangements, we recognize revenue in the period the services are provided. These 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, including natural gas fuel costs. At certain of our NGL fractionation facilities, we generate revenues using percent-of-liquids contracts. Such contracts allow us to retain a contractually determined percentage of the NGLs fractionated for customers as payment for our services. We recognize revenue from such arrangements when the NGLs we retain are sold and delivered to customers.

Onshore Natural Gas Pipelines & Services

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 Federal Energy Regulatory Commission (FERC). Revenues associated with these fee-based contracts are recognized when volumes have been physically delivered to our customer through the pipeline.

In addition, we have natural gas sales contracts associated with some of our onshore natural gas pipelines whereby revenue is recognized when we sell and deliver a volume of natural gas to a customer. Revenues from these sales contracts are based upon market-related prices as determined by the individual agreements.

Under our natural gas storage contracts, there are typically two components of revenues: (i) fixed monthly demand payments, which are associated with storage capacity reservation and paid regardless of the customer s usage of the storage facilities, and (ii) storage fees per unit of volume stored at the facilities. Revenues from demand payments are recognized throughout the period the customer reserves capacity. Revenues from storage fees are recognized in the period the services are provided.

Offshore Pipelines & Services

Our revenues from offshore natural gas pipelines are derived from fee-based contracts and are typically based on transportation fees per unit of volume transported (typically in MMBtus) multiplied by the volume delivered. We recognize revenue when volumes have been physically delivered for the customer through the pipeline.

The majority of our revenues from offshore crude oil pipelines are derived from purchase and sale arrangements whereby we purchase oil from shippers at various receipt points along our crude oil pipelines for an index-based price (less a price differential) and sell the oil back to the shippers at various redelivery points at the same index-based price. Net revenue recognized from such arrangements is based on the price differential per unit of volume (typically in barrels) multiplied by the volume delivered. We recognize revenues from such arrangements when we complete the delivery of crude oil to the purchaser.

In addition, certain of our offshore crude oil pipelines generate revenues based upon a gathering fee per unit of volume (typically in barrels) multiplied by the volume delivered to the customer. We recognize revenues from these gathering contracts when we complete delivery of the crude oil for the producer.

Revenues from offshore platform services generally consist of demand fees and commodity charges. Demand fees represent fixed-fees charged to customers who use 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 fees and commodity charges, but demand fees generally expire after a contractual fixed period of time. Revenues for platform services, including both demand fees and commodity charges, are recognized in the period the services are provided.

Petrochemical Services

We enter into isomerization and propylene fractionation fee-based processing arrangements and petrochemical product sales contracts. Under our processing arrangements, we recognize revenue in the period the services are provided. 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.

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. Revenues from these sales contracts are recognized when the 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.

5. Accounting for Equity Awards

As discussed in Note 2, we will account for our equity awards using the provisions of SFAS 123(R) beginning January 1, 2006. See Notes 2 and 3 for information regarding our adoption of this new accounting guidance. The following discussion pertains to our historical practice of accounting for equity awards using the intrinsic value method described in APB 25.

Unit Options

During 1998, EPCO adopted its 1998 Long-Term Incentive Plan (the 1998 Plan). Under this program, non-qualified incentive options to purchase a fixed number of our common units may be granted to EPCO s key employees who perform management, administrative or operational functions for us. The exercise price per unit, vesting and expiration terms, and rights to receive distributions on units granted are determined by EPCO for each grant agreement. EPCO has not granted the right to receive distributions on unvested unit options. EPCO purchases common units to fund its obligations under the 1998 Plan at fair value either in the open market or from us.

Historically, we accounted for unit options using the intrinsic value method described in APB 25. The exercise price of each option granted was equivalent to or greater than the market price of the underlying equity at the date of grant. Accordingly, no compensation expense related to unit options has been recognized in our Statements of Consolidated Operations and Comprehensive Income for the periods presented.

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. Our option-related reimbursements were $9.2 million, $3.8 million and $2.7 million in 2005, 2004 and 2003, respectively.

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Summary of 1998 Plan activity

The information in the following table shows unit option activity for EPCO personnel who work on our behalf.

	Number of Units	Weighted-average strike price
Outstanding at December 31, 2002	2,310,078	$ 14.57
Granted	35,000	22.26
Exercised	(372,078)	7.10
Forfeited	(35,000)	18.86
Outstanding at December 31, 2003	1,938,000	16.07
Granted	910,000	22.17
Exercised	(385,000)	12.79
Outstanding at December 31, 2004	2,463,000	18.84
Granted	530,000	26.49
Exercised	(826,000)	14.77
Forfeited	(85,000)	24.73
Outstanding at December 31, 2005	2,082,000	22.16
Options exercisable at:		
December 31, 2003	509,000	$ 9.68
December 31, 2004	1,154,000	$ 14.65
December 31, 2005	727,000	$ 19.19

The following table provides additional information regarding our unit options outstanding at December 31, 2005:

				Options Exercisable at December 31, 2005	
Range of Strike Prices	**Options outstanding at December 31, 2005**	**Weighted Average Remaining Contractual Life (in Years)**	**Weighted Average Strike Price**	**Number Exercisable at December 31, 2005**	**Weighted Average Strike Price**
$9.00-$12.56	118,000	4.41	$10.68	118,000	$10.68
$15.93-$17.63	225,000	5.14	16.47	225,000	16.47
$20.00-$24.73	1,249,000	7.84	22.57	384,000	23.40
$26.47-$26.95	490,000	9.57	26.49		n/a
	2,082,000			727,000	

The weighted-average fair value of options granted during 2005, 2004 and 2003 was $1.35, $2.26 and $2.17 per option, respectively.

Employee Partnership

In connection with the initial public offering of Enterprise GP Holdings in August 2005, the Employee Partnership was formed to serve as an incentive arrangement for certain employees of EPCO through a profits interest in the Employee Partnership. During 2005, the value of the profits interests was accounted for similar to a stock appreciation right. For additional information regarding the Employee Partnership, see *Relationship with EPCO and affiliates* under Note 18.

EPCO accounted for this share-based compensation arrangement under APB 25 until it adopted SFAS 123(R) on January 1, 2006. Under APB 25, the intrinsic value of the Class B limited partnership interest was accounted for similar to a stock appreciation right. EPCO s compensation expense related to this share-based compensation arrangement is allocated to us and other affiliates of EPCO pursuant to an administrative services agreement. For the year ended December 31, 2005, we were allocated $2 million of non-cash compensation expense associated with this share-based compensation arrangement.

Nonvested Units

We began issuing nonvested (or restricted) common units to key employees of EPCO and directors of our general partner in 2004. In general, our restricted common units are classified as either time-vested or performance-based. Time-vested restricted unit awards entitle recipients to acquire the underlying common units (at no cost to them) once the defined vesting period expires, subject to certain forfeiture provisions. The restrictions on time-vested restricted common units lapse four years from the date of grant.

Unearned compensation, representing the fair market value of such restricted units at the date of issuance, was charged to earnings as compensation expense on a straight-line basis over the vesting period. During the vesting period, each holder of time-vested restricted units is entitled to receive cash distributions per unit in an amount equal to those received by our common unitholders. For basic and diluted earnings per unit purposes, time-vested restricted common units are treated as outstanding units.

In general, performance-based restricted unit awards entitle recipients to acquire the underlying common units (at no cost to them) if we achieve a specified level of financial performance for certain capital projects during 2007. If we do not reach the specified financial targets by the dates identified within each agreement, these units will be forfeited. However, at December 31, 2005, we believe it is probable that financial performance will be met. Unearned compensation, representing the fair market value of these units at the date of issuance, was charged to earnings as compensation expense on a straight-line basis over the performance period. The performance-based restricted units are not entitled to vote or to receive distributions, until after (and if) we achieve the specified level of target performance. Performance-based restricted units are counted as outstanding units for dilutive earnings per unit purposes only.

At December 31, 2005, we had 751,604 restricted common units outstanding, which includes 724,454 time-vested restricted units and 27,150 performance-based restricted units. Unearned compensation attributable to restricted units was $14.6 million and $10.9 million at December 31, 2005 and 2004, respectively. We amortized $3.4 million and $0.8 million of such compensation expense to earnings in 2005 and 2004, respectively.

6. Employee Benefit Plans

During the first quarter of 2005, we acquired a controlling ownership interest in Dixie Pipeline Company (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 during 2005.

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.

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The following table shows Dixie s benefit obligations, fair value of plan assets, unfunded liabilities and accrued benefit liabilities at December 31, 2005.

	Pension Plan	Postretirement Plan
Projected benefit obligation	$ 9,434	$ 4,505
Accumulated benefit obligation	7,023	4,505
Fair value of plan assets	4,954	
Unfunded liability	4,480	4,505
Accrued benefit liability	4,348	4,747

Dixie s net pension and postretirement benefit costs for 2005 were $0.6 million and $0.2 million, respectively. Projected benefit obligations and net periodic benefit costs are based on actuarial estimates and assumptions. The weighted-average actuarial assumptions used in determining net periodic benefit costs for 2005 were as follows: discount rate of 5.75%; expected long-term return on plan assets of 7%; rate of compensation increase of 4%; and a medical trend rate of 7% in 2005 grading to an ultimate trend of rate of 5% in 2007 and later years. The weighted-average actuarial assumptions used in determining the projected benefit obligation at December 31, 2005 were as follows: discount rate of 5.5%, expected long-term rate of return on assets of 7%; rate of compensation increase of 4%; and a medical trend rate of 6% for 2006 grading to an ultimate trend of 5% for 2007 and later years.

Future benefits expected to be paid from Dixie s pension and postretirement plans are as follows for the periods indicated:

	Pension Plan	Postretirement Plan
2006	$ 448	$ 272
2007	682	289
2008	558	283
2009	800	302
2010	832	330
2011 through 2015	4,804	1,883
Total	$ 8,124	$ 3,359

7. Financial Instruments

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

We recognize financial instruments as assets and liabilities on our Consolidated Balance Sheets based on fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument s gains and losses offset the related results of the hedged item in earnings for a fair value hedge

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and are deferred in other comprehensive income for a cash flow hedge. Gains and losses related to a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings.

To qualify as a hedge, the item to be hedged must be exposed to commodity or interest rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS 133, (as amended and interpreted). We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness of the hedge is recorded in current earnings.

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

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess cash flow risk related to interest rates by identifying and measuring changes in our interest rate exposures that may impact future cash flows and evaluating hedging opportunities to manage these risks. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis models to forecast the expected impact of changes in interest rates on our future cash flows. Enterprise Products GP oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

We manage a portion of our interest rate exposures 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. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt in the current business environment.

As summarized in the following table, we had eleven interest rate swap agreements outstanding at December 31, 2005 that were accounted for as fair value hedges.

Hedged Fixed Rate Debt	Number Of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Amount
Senior Notes B, 7.50% fixed rate, due Feb. 2011	1	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 7.26%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.8%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 5.24%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 4.99%	$200 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.

These eleven agreements have a combined notional amount of $1.1 billion and match the maturity dates of the underlying debt being hedged. Under each swap agreement, we pay the counterparty a variable interest rate based on six-month London interbank offered rate (LIBOR) (plus an applicable margin as defined in each swap agreement), and receive back from the counterparty a fixed interest rate payment based on the stated interest rate of the debt being hedged, with both payments calculated using the notional amounts stated in each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the settlement period). The settlement amount is amortized ratably to earnings as either an increase or a decrease in interest expense over the settlement period.

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The total fair value of these eleven interest rate swaps at December 31, 2005, was a liability of $19.2 million, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the years ended December 31, 2005 and 2004 reflects a $10.8 million and $9.1 million benefit from these swap agreements, respectively.

During the first nine months of 2004, we entered into eight forward starting interest rate swaps having an aggregate notional value of $2 billion in anticipation of our financing activities associated with closing the GulfTerra Merger. Our purpose in entering into these financial instruments was to effectively hedge the underlying U.S. treasury rate related to our issuance of $2 billion in principal amount of fixed-rate debt. In October 2004, the Operating Partnership issued $2 billion of private placement debt under Senior Notes E through H. Each of the forward starting swaps was designated as a cash flow hedge under SFAS 133.

In April 2004, we elected to terminate the initial four forward starting swaps in order to manage and maximize the value of the swaps and to reduce future debt service costs. As a result, we received $104.5 million in cash from the counterparties. In September 2004, we settled the remaining four swaps resulting in an $85.1 million payment to the counterparties.

The following table shows the notional amount covered by each forward starting swap and the cash gain (loss) associated with each swap upon settlement:

Term of Anticipated Debt Offering (or Forecasted Transaction)	Notional Amount of Debt covered by Forward Starting Swaps	Net Cash Received upon Settlement of Forward Starting Swaps
3-year, fixed rate debt instrument	$ 500,000	$ 4,613
5-year, fixed rate debt instrument	500,000	7,213
10-year, fixed rate debt instrument	650,000	10,677
30-year, fixed rate debt instrument	350,000	(3,098)
Total	$2,000,000	$ 19,405

The net gain of $19.4 million from these settlements will be reclassified from Accumulated Other Comprehensive Income (AOCI) to reduce interest expense over the life of the associated debt. We reclassified $4 million and $1.3 million from AOCI during 2005 and 2004, respectively, which reduced the amount of interest expense we recognized.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and 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 risks associated with natural gas and NGLs, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to hedge our exposure to price risks associated with (i) natural gas purchases, (ii) NGL 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 or NGLs. The commodity financial instruments we utilize may be settled in cash or with another financial instrument. Historically, we have not hedged our exposure to risks associated with petrochemical products, including MTBE.

We have adopted a policy to govern our use of commodity financial instruments to manage the risks of our natural gas and NGL businesses. The objective of this policy is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by

Enterprise Products GP. We may enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 24 months. Enterprise Products GP oversees the strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

At December 31, 2005, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of economic hedges. The fair value of our commodity financial instrument portfolio at December 31, 2005 was a liability of $0.1 million. We recorded nominal amounts of earnings from our commodity financial instruments during 2005, 2004 and 2003.

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 financial instruments at the dates indicated:

	December 31, 2005		December 31, 2004	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents	$ 57,050	$ 57,050	$ 50,713	$ 50,713
Accounts receivable	1,454,583	1,454,583	1,083,536	1,083,536
Commodity financial instruments (1)	1,114	1,114	3,904	3,904
Interest rate hedging financial instruments (2)			505	505
Financial liabilities:				
Accounts payable and accrued expenses	1,763,390	1,763,390	1,466,115	1,466,115
Fixed-rate debt (principal amount)	4,359,068	4,395,110	3,725,469	3,922,459
Variable-rate debt	507,000	507,000	563,229	563,229
Commodity financial instruments (1)	1,167	1,167	3,685	3,685
Interest rate hedging financial instruments (2)	19,179	19,179		

(1) Represent commodity financial 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) Represent interest rate hedging financial instrument transactions that have not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

8. Cumulative Effect of Changes in Accounting Principles

In 2005 and 2004, we recorded various amounts related to the cumulative effect of changes in accounting principles, including (i) $4.2 million in December 2005 related to our implementation of FIN 47 and (ii) a combined $10.8 million during 2004 related to changing a subsidiary s accounting method for planned major maintenance activities and the method we use to account for our investment in Venice Energy Services Company, LLC (VESCO).

Implementation of FIN 47. In December 2005, we adopted Financial Accounting Standards Board (FIN) 47, which required us to record a liability for asset retirement obligations (AROs) in which the timing and/or amount of settlement of the obligation are uncertain. These conditional asset retirement obligations were not addressed in SFAS

143, which we adopted on January 1, 2003. We recorded a

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cumulative effect of change in accounting principle of $4.2 million in connection with our implementation of FIN 47, which represents the depreciation and accretion expense we would have recognized had we recorded these conditional asset retirement obligations when incurred. For additional information regarding our asset retirement obligations, see Note 10.

BEF major maintenance costs. In January 2004, our Belvieu Environmental Fuels (BEF) subsidiary changed its accounting method for planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred approach. BEF owns an octane additive production facility that undergoes periodic planned outages of 30 to 45 days for major maintenance work. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services, and other related items. This change conformed BEF s accounting policy for such costs to that followed by our other operations, which use the expense-as-incurred approach. As such, we believe the change is to a method that is preferable under the circumstances. The cumulative effect of this accounting change for years prior to 2004 resulted in a benefit of $7 million.

Investment in VESCO. In July 2004, we changed the method we use to account for our investment in VESCO from the cost method to the equity method in accordance with EITF 03-16, *Accounting for Investments in Limited Liability Companies.* EITF 03-16 requires partnership-type accounting for investments in limited liability companies that have separate ownership accounts for each investor. As a result of EITF 03-16, investors are required to apply the equity method of accounting to their investments at a much lower ownership threshold (typically any ownership interest greater than 3% to 5%) than the traditional 20% threshold applied under APB 18, *The Equity Method of Accounting for Investments in Common Stock.*

Prior to adopting EITF 03-16, we accounted for our 13.1% investment in VESCO using the cost method. As a result, we recognized dividend income from VESCO to the extent we received cash distributions from them. Our cumulative effect adjustment for EITF 03-16 represents (i) equity earnings from VESCO that would have been recorded had we used the equity method of accounting prior to 2004 less (ii) the dividend income we recorded from VESCO prior to 2004 using the cost method. The cumulative effect of this accounting change resulted in a benefit of $3.8 million.

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For the periods indicated, the following table shows unaudited pro forma net income for the years ended December 31, 2005, 2004 and 2003, assuming the three accounting changes noted above were applied retroactively to January 1, 2003.

	For the Year Ended December 31,		
	2005	2004	2003
Pro Forma income statement amounts:			
Historical net income	$419,508	$268,261	$104,546
Adjustments to derive pro forma net income:			
Effect of implementation of FIN 47			
Remove cumulative effect of change in accounting principle recorded in December 2005	4,208		
Record depreciation and accretion expense associated with conditional asset retirement obligations	(735)	(373)	(246)
Effect of change from the accrue-in-advance method to the expense-as-incurred method for BEF major maintenance costs:			
Remove historical equity in income (losses) recorded for BEF			31,508
Record equity in (income) losses from BEF calculated using new method of accounting for major maintenance costs			(31,800)
Remove cumulative effect of change in accounting principle recorded in January 2004		(7,013)	
Remove minority interest expense associated with change in accounting principle Sun 33.33% portion		2,338	
Effect of changing from the cost method to the equity method with respect to our investment in VESCO:			
Remove cumulative effect of change in accounting principle recorded in July 2004		(3,768)	
Remove historical dividend income recorded from VESCO		(2,136)	(5,595)
Record equity earnings from VESCO		2,429	5,133
Pro forma net income	422,981	259,738	103,546
Enterprise Products GP interest	(71,066)	(36,938)	(20,705)
Pro forma net income available to limited partners	$351,915	$222,800	$ 82,841
Pro forma per unit data (basic):			
Historical units outstanding	381,857	265,370	199,915
Per unit data:			
As reported	$ 0.91	$ 0.87	$ 0.42
Pro forma	$ 0.92	$ 0.84	$ 0.41
Pro forma per unit data (diluted):			
Historical units outstanding	382,963	266,045	206,367

Per unit data:			
As reported	$ 0.91	$ 0.87	$ 0.41
Pro forma	$ 0.92	$ 0.84	$ 0.40

9. Inventories

Our inventory amounts were as follows at the dates indicated:

	December 31, 2005	December 31, 2004
Working inventory	$279,237	$171,485
Forward-sales inventory	60,369	17,534
Inventory	$339,606	$189,019

A general description of our inventories is as follows:

§ Our regular trade (or working) inventory is primarily comprised of inventories of natural gas, NGLs and petrochemical products that are available for sale or used in the provision of services. This inventory is valued at the lower of average cost or market, with market being determined by industry-related posted prices such as those published by Oil Price Information Service (OPIS) and Chemical Market Associates, Inc. (CMAI).

§ The forward-sales inventory is comprised of segregated NGL volumes dedicated to the fulfillment of forward sales contracts and is valued at the lower of average cost or market, with market being defined as the weighted-average sales price for NGL volumes to be delivered in future months on the forward sales contracts.

Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes and other related costs including terminal and storage fees, vessel inspection and demurrage charges and processing costs.

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. As with inventory volumes we purchase for cash, 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 market conditions in the NGL, natural gas and petrochemical industry, we occasionally recognize lower of average cost or market (LCM) adjustments when the cost of our inventories exceed their net realizable value. These non-cash adjustments are charged to operating costs and expenses and generally affect our segment operating results in the following manner:

§ NGL inventory write-downs are recorded as a cost of our NGL marketing activities within our NGL Pipelines & Services business segment;

§ Natural gas inventory write downs are recorded as a cost of our natural gas pipeline operations within our Onshore Natural Gas Pipelines & Services business segment; and

§ Petrochemical inventory write downs are recorded as a cost of our petrochemical marketing activities or octane additive production business within our Petrochemical Services business segment, as applicable.

For the years ended December 31, 2005, 2004 and 2003, we recognized LCM adjustments of approximately $21.9 million, $9.4 million and $16.9 million, respectively. The majority of these write-downs were taken against NGL inventories. 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.

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	At December 31, 2005	2004
Plants and pipelines [1]	5-35(5)	$8,209,580	$7,691,197
Underground and other storage facilities [2]	5-35(6)	549,923	531,394
Platforms and facilities [3]	23-31	161,807	162,645
Transportation equipment [4]	3-10	24,939	7,240
Land		38,757	29,142
Construction in progress		854,595	230,375
Total		9,839,601	8,651,993
Less accumulated depreciation		1,150,577	820,526
Property, plant and equipment, net		$8,689,024	$7,831,467

(1) Plants and pipelines includes processing plants; NGL, petrochemical, 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 includes underground product storage caverns; storage tanks; water wells; and related assets.

(3) Platforms and facilities includes 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: processing plants, 20-35 years; pipelines, 18-35 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings 20-35 years; and laboratory and shop equipment, 5-35 years.

(6) In general, the estimated useful lives of major components of this category are: underground storage facilities, 20-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

Depreciation expense for the years ended December 31, 2005, 2004 and 2003 was $328.7 million, $161 million and $101 million, respectively. A significant portion of the year-to-year increase in depreciation expense between 2005 and 2004 is attributable to assets we acquired in connection with the GulfTerra Merger, which was completed on September 30, 2004.

We capitalized $22 million, $2.8 million and $1.6 million of interest associated with construction projects during 2005, 2004 and 2003, respectively.

Asset retirement obligations. We have recorded asset retirement obligations related to legal requirements to perform retirement activities as specified in contractual arrangements and/or governmental regulations. In general, our asset retirement obligations 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 asset retirement obligations may result from the renovation or demolition of certain assets containing hazardous substances such as asbestos.

Previously, we recorded asset retirement obligations associated with the future retirement and removal activities of certain offshore assets located in the Gulf of Mexico. In December 2005, we adopted FIN 47 and recorded an additional $10.1 million in connection with conditional asset retirement obligations. The cumulative effect of this change in accounting principle for years prior to 2005 was a non-cash charge of $4.2 million. None of our assets are legally restricted for purposes of settling asset retirement obligations.

The following table presents information regarding our asset retirement obligations since December 31, 2004.

Asset retirement obligation liability balance, December 31, 2004	$	6,236
Adoption of FIN 47 for conditional obligations		10,076
Accretion expense		483
Asset retirement obligation liability balance, December 31, 2005	$	16,795

Property, plant and equipment at December 31, 2005 and 2004 includes $0.9 million and $0.2 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. Also, based on information currently available, we estimate that accretion expense will approximate $1.4 million for 2006, $1.1 million for 2007, $1.2 million for 2008, $1.3 million for 2009 and $1.4 million for 2010.

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2005 and 2004 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our financial statements.

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11. Investments in and Advances to Unconsolidated Affiliates

Our investments in and advances to our unconsolidated affiliates are grouped according to the business segment to which they relate. For a general discussion of our business segments, see Note 17. The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated.

	Ownership Percentage at December 31, 2005	Investments in and advances to Unconsolidated Affiliates at December 31, 2005	December 31, 2004
NGL Pipelines & Services:			
Dixie Pipeline Company (Dixie[1])			$ 32,514
Venice Energy Services Company, LLC (VESCO)	13.1%	$ 39,689	38,437
Belle Rose NGL Pipeline LLC (Belle Rose[2])			10,172
K/D/S Promix LLC (Promix)	50%	65,103	65,748
Baton Rouge Fractionators LLC (BRF)	32.3%	25,584	27,012
Onshore Natural Gas Pipelines & Services:			
Evangeline [3]	49.5%	3,151	2,810
Coyote Gas Treating, LLC (Coyote)	50%	1,493	2,441
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C. (Poseidon)	36%	62,918	63,944
Cameron Highway Oil Pipeline Company (Cameron Highway)[4]	50%	58,207	114,354
Deepwater Gateway, L.L.C. (Deepwater Gateway[5])	50%	115,477	56,527
Neptune Pipeline Company, L.L.C. (Neptune)	25.67%	68,085	72,052
Nemo Gathering Company, LLC (Nemo)	33.92%	12,157	12,586
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC (BRPC)	30%	15,212	15,617
La Porte [6]	50%	4,845	4,950
Total		$471,921	$519,164

(1) We acquired an additional 20% ownership interest in Dixie in January 2005 and an additional 26.1% ownership interest in February 2005. As a result of these acquisitions, Dixie became a consolidated subsidiary.

(2) We acquired an additional 41.7% ownership interest in Belle Rose in June 2005. As a result of this acquisition, Belle Rose became a consolidated subsidiary.

(3) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.

(4) Cameron Highway began deliveries of Gulf of Mexico crude oil production to major refining markets along the Texas Gulf Coast during the first quarter of 2005. In June 2005, we received a $47.5 million return of our investment in Cameron Highway due to the refinancing of Cameron Highway s project debt. For additional information regarding the refinancing of Cameron Highway s debt, please read Note 14.

(5) In March 2005, we contributed $72 million to Deepwater Gateway to fund our share of the repayment of its $144 million term loan. For additional information regarding Deepwater Gateway s repayment of its term loan, please read Note 14.

(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 an investee exceeds the carrying value of the historical net assets of the investee we are purchasing. Such excess amounts (or excess costs) are a component of our investments in and advances to unconsolidated affiliates.

At December 31, 2005, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Nemo included excess cost amounts. At the time of purchase, an analysis of each of these investments indicated that such excess cost amounts were attributable to either (i) an increase in the fair value of tangible or qualifying intangible assets owned by each entity over its historical carrying values for such assets or (ii) it was unattributable and deemed to be goodwill.

To the extent that we attribute all or a portion of an excess cost amount to an increase in the fair value of assets, 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.

At December 31, 2005, our investments in and advances to unconsolidated affiliates included $48.1 million of excess cost amounts, all of which were attributed to increases in fair value of the underlying assets of the investees. At December 31, 2004, our excess cost amounts totaled $83.6 million, of which $74.3 million was attributed to increases in fair value of the underlying assets and the remainder to goodwill. The decrease in total excess cost during 2005 is due to the consolidation of Dixie and amortization of excess cost amounts attributable to the fair value of underlying assets. Equity earnings from unconsolidated affiliates were reduced by $2.3 million, $1.9 million and $1.6 million during 2005, 2004 and 2003, respectively, due to the amortization of excess cost amounts.

The following table shows our equity in income (loss) of unconsolidated affiliates for the periods indicated:

	For the Year Ended December 31,		
	2005	2004	2003
NGL Pipelines & Services:			
Dixie [1]	$ 1,103	$ 1,273	$ 1,323
VESCO [2]	1,412	6,132	
Belle Rose [1]	(151)	(402)	(55)
Promix	1,876	859	2,106
BRF	1,313	2,190	832
Tri-States NGL Pipeline LLC (Tri-States[1])		(154)	1,542
Wilprise Pipeline Company, LLC (Wilprise[1])			276
EPIK [1, 3]			1,818
Onshore Natural Gas Pipelines & Services:			
Evangeline	331	231	131
Coyote	2,053	541	
Offshore Pipelines & Services:			
Poseidon	7,279	2,509	
Cameron Highway [4]	(15,872)	(461)	
Deepwater Gateway	10,612	3,562	
Neptune	2,019	(1,852)	1,014
Nemo	1,774	1,628	1,268
Starfish Pipeline Company, LLC (Starfish[5])	313	3,473	3,279
Petrochemical Services:			
BRPC	1,224	1,943	1,198
La Porte	(738)	(710)	(698)
Belvieu Environmental Fuels, L.P. (BEF[1])			(27,864)
Olefins Terminal Corporation (OTC [1])			(77)
Other:			
Gulf Terra GP [6]		32,025	(53)
Total	$ 14,548	$52,787	$(13,960)

(1) We acquired additional ownership interests in or control over these entities since January 1, 2003 resulting in our consolidation of each company s post-acquisition financial results with those of our own. Our consolidation of each company s post-acquisition financial results began in the following periods: EPIK, March 2003; Wilprise, October 2003; OTC, August 2003; BEF, September 2003; Tri-States, April 2004; Dixie, February 2005; and Belle Rose, June 2005.

(2)

As a result of adopting EITF 03-16 during 2004, we changed from the cost method to the equity method of accounting with respect to our investment in VESCO. See Note 8 for information regarding this accounting change.

(3) EPIK refers to EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively.

(4) Equity earnings from Cameron Highway for the year ended December 31, 2005 were reduced by a charge of $11.5 million for costs associated with the refinancing of Cameron Highway s project debt (see Note 14).

(5) We were required under a consent decree published for comment by the FTC on September 30, 2004 to sell our 50% interest in Starfish. On March 31, 2005, we sold this asset to a third-party.

(6) In connection with the GulfTerra Merger (see Note 12), GulfTerra GP became a wholly owned consolidated subsidiary of ours on September 30, 2004. We had previously accounted for our 50% ownership interest in GulfTerra GP as an equity method investment from December 15, 2003 through September 29, 2004.

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NGL Pipelines & Services

At December 31, 2005, 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 and NGL fractionation facility and related storage and pipeline assets located in south Louisiana. On July 1, 2004, we changed our method of accounting for VESCO from the cost method to the equity method in accordance with EITF 03-16 (see Note 8).

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 32.3% interest in BRF, which owns an NGL fractionation facility located in south Louisiana.

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,	
	2005	**2004**
BALANCE SHEET DATA:		
Current assets	$ 72,784	$ 93,017
Property, plant and equipment, net	328,270	348,168
Other assets	12,471	13,017
Total assets	$413,525	$454,202
Current liabilities	$ 32,886	$ 72,427
Other liabilities	7,343	6,882
Combined equity	373,296	374,893
Total liabilities and combined equity	$413,525	$454,202

	For Year Ended December 31,		
	2005	**2004**	**2003**
INCOME STATEMENT DATA:			
Revenues	$207,775	$244,521	$258,939
Operating income	6,696	40,259	34,630
Net income	6,509	40,355	34,500

Onshore Natural Gas Pipelines & Services

At December 31, 2005, 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 system located in south Louisiana.

Coyote. We own a 50% interest in Coyote, which owns a natural gas treating facility located in the San Juan Basin of southwestern Colorado.

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, 2005	2004
BALANCE SHEET DATA:		
Current assets	$ 41,674	$21,652
Property, plant and equipment, net	36,380	38,821
Other assets	28,732	35,149
Total assets	$106,786	$95,622
Current liabilities	$ 72,441	$24,365
Other liabilities	32,737	37,210
Combined equity	1,608	34,047
Total liabilities and combined equity	$106,786	$95,622

	For Year Ended December 31, 2005	2004	2003
INCOME STATEMENT DATA:			
Revenues	$347,561	$257,539	$230,429
Operating income	12,908	8,552	9,275
Net income	4,721	4,657	5,037

Offshore Pipelines & Services

At December 31, 2005, 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. The Cameron Highway Oil Pipeline commenced operations during the first quarter of 2005.

Deepwater Gateway. We own a 50% interest in Deepwater Gateway, which owns the Marco Polo platform located in Green Canyon Block 608 of 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 the Manta Ray Offshore Gathering System and Nautilus System, 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.

In connection with obtaining regulatory approval for the GulfTerra Merger, we were required by the U.S. Federal Trade Commission (FTC) to sell our ownership interest in Starfish by March 31, 2005. We classified the $36.6 million carrying value of this investment under Assets held for sale on our consolidated balance sheet at December 31, 2004. In March 2005, we sold this asset to a third-party for $42.1 million in cash and realized a gain on the sale of $5.5 million.

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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, 2005	At December 31, 2004
BALANCE SHEET DATA:		
Current assets	$ 141,756	$ 79,196
Property, plant and equipment, net	1,201,926	712,182
Other assets	7,961	528,443
Total assets	$ 1,351,643	$ 1,319,821
Current liabilities	$ 120,611	$ 71,758
Other liabilities	511,633	526,990
Combined equity	719,399	721,073
Total liabilities and combined equity	$ 1,351,643	$ 1,319,821

	For Year Ended December 31, 2005	2004	2003
INCOME STATEMENT DATA:			
Revenues	$1,309,836	$88,603	$76,168
Operating income	78,027	46,938	39,658
Net income	29,161	38,473	33,700

Petrochemical Services

At December 31, 2005, our Petrochemical 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.

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, 2005	At December 31, 2004
BALANCE SHEET DATA:		
Current assets	$ 5,508	$ 3,266
Property, plant and equipment, net	54,751	57,516
Total assets	$ 60,259	$ 60,782
Current liabilities	$ 1,178	$ 438

Other liabilities	1	
Combined equity	59,080	60,344
Total liabilities and combined equity	$ 60,259	$ 60,782

	For Year Ended December 31,		
	2005	2004	2003
INCOME STATEMENT DATA:			
Revenues	$ 16,849	$ 18,378	$ 14,512
Operating income	2,606	5,131	2,726
Net income	2,650	5,151	2,685

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Equity earnings from unconsolidated affiliates for 2003 includes a $22.5 million loss related to non-cash impairment charges recorded by BEF, a former unconsolidated affiliate that we now wholly own and consolidate. As a result of declining domestic demand and a prolonged period of weak MTBE production economics, several of BEF s competitors announced their withdrawal from the marketplace during 2003. Due to the deteriorating business environment and outlook for domestic MTBE sales and the completion of its preliminary engineering studies regarding conversion alternatives, BEF evaluated the carrying value of its long-lived assets for impairment during the third quarter of 2003. This review indicated that the carrying value of its long-lived assets exceeded their collective fair value, which resulted in BEF recognizing a non-cash asset impairment charge of $67.5 million. Based on our ownership interest at the time, we recorded our 33.3% share of this loss ($22.5 million) in equity earnings from BEF.

Other, non-segment

The Other, non-segment category is presented for financial reporting purposes only to reflect the historical equity earnings we received from GulfTerra GP. We acquired a 50% membership interest in GulfTerra GP on December 15, 2003, in connection with the GulfTerra Merger. Our $425 million investment in GulfTerra GP was accounted for using the equity method until the GulfTerra Merger was completed on September 30, 2004. On that date, GulfTerra GP became a wholly owned consolidated subsidiary of ours. Since the historical equity earnings of GulfTerra GP were based on net income amounts allocated to it by GulfTerra, it is impractical for us to allocate the equity income we received during the periods presented to each of our new business segments. Therefore, we have segregated equity earnings from GulfTerra GP from our other segment results to aid in comparability between the periods presented.

12. Business Combinations and Other Acquisitions

2003 Transactions

Our expenditures for business combinations and acquisitions during 2003 were $37.3 million, which included $4.9 million of purchase price adjustments relating to transactions that occurred prior to 2003.

In March 2003, we purchased an additional 50% ownership interest in EPIK, which owns our NGL export terminal located on the Houston Ship Channel. Also in March 2003, we acquired entities that own the Port Neches petrochemical pipeline. In September 2003, we acquired an additional ownership interest in BEF, which owns our octane additive production facility. In October 2003, we purchased an additional 37.4% ownership interest in Wilprise, which owns an NGL pipeline in Louisiana. In November 2003, we purchased an additional 50% ownership interest in OTC. As a result of these transactions, all of these entities became consolidated subsidiaries of ours.

Our purchase of a 50% equity interest in GulfTerra GP in December 2003 from El Paso was accounted for as an investment in an unconsolidated affiliate (see Note 11). Upon completion of the GulfTerra Merger, GulfTerra GP became a consolidated subsidiary of ours.

2004 Transactions

Our expenditures for business combinations and acquisitions during 2004 were $4.1 billion, which includes consideration paid or granted to complete the GulfTerra Merger in September 2004.

GulfTerra Merger. In September 2004, we completed the merger of GulfTerra with a wholly owned subsidiary of ours. In addition, we completed certain other transactions related to the merger, including (i) the receipt of Enterprise Products GP s contribution of a 50% membership interest in GulfTerra GP, which was acquired by Enterprise Products GP from El Paso, and (ii) the purchase of certain midstream energy assets located in South Texas from El Paso. As a result of the merger transactions, GulfTerra and GulfTerra GP became wholly owned subsidiaries of ours.

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The aggregate value of the total consideration we paid or issued to complete the GulfTerra Merger was approximately $4 billion. The merger occurred in several interrelated transactions as described below.

§ *Step One*. In December 2003, we purchased a 50% membership interest in GulfTerra GP from El Paso for $425 million in cash. GulfTerra GP owned a 1% general partner interest in GulfTerra. Prior to completion of the GulfTerra Merger, we accounted for our investment in GulfTerra GP using the equity method of accounting. The $425 million in funds required to complete Step One was borrowed under an interim term loan and our pre-merger revolving credit facilities. This borrowing was fully repaid using net proceeds from equity offerings completed during 2004.

§ *Step Two*. On September 30, 2004, the GulfTerra Merger was completed and GulfTerra and GulfTerra GP became wholly-owned subsidiaries of ours. The GulfTerra Merger was accounted for using purchase accounting. Step Two of the GulfTerra Merger included the following transactions:

  § Immediately prior to closing the GulfTerra Merger, Enterprise Products GP acquired from El Paso the remaining 50% membership interest in GulfTerra GP for $370 million in cash and the issuance of a 9.9% membership interest in Enterprise Products GP to El Paso. Subsequently, Enterprise Products GP contributed this 50% membership interest in GulfTerra GP to us without the receipt of additional general partner interest, common units or other consideration. Enterprise Products GP borrowed the $370 million from an affiliate of EPCO, which obtained the required funds through a loan from EPCO (which at the time indirectly owned the remaining membership interests in Enterprise Products GP).

  § Immediately prior to closing the GulfTerra Merger, we paid $500 million in cash to El Paso for 10,937,500 Series C units of GulfTerra and 2,876,620 common units of GulfTerra. The remaining 57,762,369 GulfTerra common units were converted into 104,549,823 of our common units, of which 13,454,498 were issued to El Paso.

§ *Step Three*. Immediately after Step Two was completed, we acquired certain midstream assets located in South Texas from El Paso for $155.3 million in cash.

In connection with closing the merger transactions, our Operating Partnership borrowed an aggregate $2.8 billion under its credit facilities to fund our cash payment obligations under Steps Two and Three of the GulfTerra Merger and to finance tender offers for GulfTerra s outstanding senior and senior subordinated notes.

The total consideration paid or granted for the GulfTerra Merger (including $7 million of purchase price adjustments paid during 2005) is summarized below:

Step One transaction:	
Cash payment by us to El Paso for initial 50% membership interest in GulfTerra GP (a non-voting interest) made in December 2003	$ 425,000
Total Step One consideration	425,000
Step Two transactions:	
Cash payment by us to El Paso for 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units	500,000
Fair value of equity interests granted to acquire remaining 50% membership interest in GulfTerra GP (voting interest) (1)	461,347
Fair value of our common units issued in exchange for remaining GulfTerra common units (see Note 15)	2,445,420
Fair value of our additional equity interests granted for unit awards and Series F2 convertible units	3,675
Fair value of receivable from El Paso for transition support payments (2)	(40,313)
Transaction fees and other direct costs incurred by us as a result of the GulfTerra Merger (3)	31,011
Total Step Two consideration	3,401,140
Total Step One and Step Two consideration	3,826,140
Step Three transaction:	
Purchase of South Texas midstream assets from El Paso	155,277
Total consideration for Steps One through Three	$ 3,981,417

(1) This fair value is based on 50% of an implied $922.7 million total value of GulfTerra GP, which assumes that the $370 million cash payment made by Enterprise Products GP to El Paso represented consideration for a 40.1% interest in GulfTerra GP. The 40.1% interest was derived by deducting the 9.9% membership interest in Enterprise Products GP granted to El Paso in this transaction from the 50% membership interest in GulfTerra GP that Enterprise Products GP received. The fair value of $461.3 million assigned to this voting membership interest in GulfTerra GP compares favorably to the $425 million paid to El Paso by us to purchase our initial 50% non-voting membership interest in GulfTerra GP in December 2003. The contribution of this 50% membership interest to us is allocated for financial reporting purposes to our limited partners and general partner based on the respective ownership percentages and the related allocation of profits and losses of 98% and 2%, respectively, both of which are consistent with the partnership agreement.

(2) Reflects the present value of a contract-based receivable from El Paso received as part of the negotiated net consideration reached in Step One of the GulfTerra Merger. The agreements between us and El Paso provide that for a period of three years following the closing of the GulfTerra Merger, El Paso will make transition support payments to us in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in twelve equal monthly installments for each such year. The $45 million receivable from El Paso was discounted to fair value and recorded as a reduction in the purchase consideration for GulfTerra. As December 31, 2005, the fair value of the current portion and non-current portion of this

contract-based receivable was $11.3 million and $8.3 million, respectively; these amounts are reflected as a component of Prepaid and other current assets and Long-term receivables on our Consolidated Balance Sheet as of December 31, 2005.

(3) As a result of the GulfTerra Merger, we incurred expenses of approximately $31 million for various transaction fees and other direct costs. These direct costs include fees for legal, accounting, printing, financial advisory and other services rendered by third-parties to us over the course of the GulfTerra Merger transactions. This amount also includes $3.4 million of involuntary severance costs.

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In connection with the GulfTerra Merger, we were required under a consent decree to sell our 50% interest in Starfish, which owns the Stingray natural gas pipeline, and an undivided 50% interest in a Mississippi propane storage facility. We completed the sale of the storage facility in December 2004 and the sale of our investment in Starfish in March 2005.

In addition to the GulfTerra Merger, our business combinations and acquisitions during 2004 included the purchase of (i) an additional 16.7% ownership interest in Tri-States, (ii) an additional 10% ownership interest in Seminole, (iii) the remaining 33.3% ownership interest in BEF and (iv) certain assets located in Morgan s Point, Texas.

As a result of the final purchase price allocation for the GulfTerra Merger, we recorded $743.4 million of amortizable intangible assets and $387.1 million of goodwill. For additional information regarding these intangible assets, please read Note 13.

2005 Transactions

Our expenditures for business combinations and acquisitions during 2005 were $326.6 million, which included $8.3 million of purchase price adjustments relating to transactions that occurred prior to 2005.

In January 2005, we acquired indirect ownership interests in the Indian Springs Gathering System and Indian Springs natural gas processing plant for $74.9 million. In January and February 2005, we acquired an additional 46% of the ownership interests in Dixie for $68.6 million. In June 2005, we acquired additional indirect ownership interests in our Mid-America Pipeline System and Seminole Pipeline for $25 million. Also in June 2005, we acquired an additional 41.7% ownership interest in Belle Rose, which owns a NGL pipeline located in Louisiana, for $4.4 million. In July 2005, we purchased three underground NGL storage facilities and four propane terminals from Ferrellgas L.P. (Ferrellgas) for $145.5 million in cash. Dixie and Belle Rose became consolidated subsidiaries of ours in 2005 as a result of our acquisition of additional ownership interests in these two entities.

During 2005, we paid El Paso an additional $7 million in purchase price adjustments related to the GulfTerra Merger, the majority of which were related to merger-related financial advisory services and involuntary severance costs. In addition, we made various minor revisions to the GulfTerra Merger purchase price allocation before it was finalized on September 30, 2005.

Purchase Price Allocation for 2005 Transactions

Our 2005 acquisitions and post-closing purchase price adjustments were accounted for using the purchase method of accounting and, accordingly, the cost of each has been allocated to the assets acquired and liabilities assumed based on their estimated preliminary fair values as follows:

	Indian Springs	Dixie	Ferrellgas Assets	Other (2)	Total
Purchase price allocation:					
Assets acquired in business combination:					
Current assets	$ 252	$ (476)	$ 6,901	$ 2,217	$ 8,894
Property, plant and equipment, net	40,321	90,306	144,092	30,358	305,077
Investments in and advances to unconsolidated affiliates (1)		(36,279)		(10,017)	(46,296)
Intangible assets	19,095		109	1,009	20,213
Other assets		31,185		(3,694)	27,491
Total assets acquired	59,668	84,736	151,102	19,873	315,379
Liabilities assumed in business combination:					
Current liabilities	(118)	(2,758)	(5,580)	(4,761)	(13,217)
Long-term debt		(9,982)			(9,982)
Other long-term liabilities	(61)	(7,697)			(7,758)
Minority interest		(4,586)		11,603	7,017
Total liabilities assumed	(179)	(25,023)	(5,580)	6,842	(23,940)
Total assets acquired less liabilities assumed	59,489	59,713	145,522	26,715	291,439
Total consideration given	74,854	68,608	145,522	37,618	326,602
Goodwill	$ 15,365	$ 8,895	$	$ 10,903	$ 35,163

(1) Represents carrying value of our investment prior to consolidation.

(2) Includes purchase accounting adjustments for the GulfTerra Merger and preliminary purchase price allocations for the Mid-America, Seminole, Belle Rose and petrochemical pipeline transactions.

The purchase price allocations for our 2005 transactions are preliminary. We engaged an independent third-party business valuation expert to assess the fair value of tangible and intangible assets acquired in connection with the Indian Springs, Dixie, Belle Rose and Ferrellgas transactions. This information will assist us in developing final purchase price allocations for these transactions. Management developed its own fair value estimates of assets acquired and liabilities assumed in connection with the remaining 2005 transactions. Our preliminary values are subject to final valuation reports and additional information.

Selected Pro Forma Financial Information (Unaudited)

Our historical operating results were affected by business combinations and asset acquisitions during 2005 and 2004. Our most significant recent transaction was the GulfTerra Merger. Since the closing date of the GulfTerra

Merger was September 30, 2004, our Statements of Consolidated Operations and Comprehensive Income do not include any earnings from GulfTerra prior to October 1, 2004. The effective closing date of our purchase of the South Texas midstream assets (Step Three of the GulfTerra Merger) was September 1, 2004. As a result, our Statements of Consolidated Operations and Comprehensive Income for 2004 include four months of earnings from the South Texas midstream assets. Our 2005 results already reflect the businesses we acquired in connection with the GulfTerra Merger; therefore, no pro forma adjustments are necessary for the 2005 period. Due to the immaterial nature of our other business combinations and acquisitions since 2004, our selected pro forma financial information includes only adjustments related to the GulfTerra Merger. Our pro forma basic and diluted earnings per unit amounts for 2005 are practically the same as our actual basic and diluted earnings per unit for 2005.

The pro forma information presented in the following table is based on financial data available to us and includes certain estimates and assumptions made by our management. Our pro forma earnings data has been prepared as if the GulfTerra Merger transaction had been completed on January 1, 2004, as opposed to September 30, 2004. As a result, our pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had the GulfTerra Merger transactions actually occurred on this earlier date.

	For Year Ended December 31, 2004
Pro forma earnings data:	
Revenues	$ 9,615.1
Costs and expenses	$ 9,067.2
Operating income	$ 576.3
Net income	$ 335.4
Pro forma net income	$ 335.4
Less incentive earnings allocations to Enterprise Products GP	(46.1)
Pro forma net income after incentive earnings allocation	289.3
Multiplied by Enterprise Products GP ownership interest	2.0%
Standard earnings allocation to Enterprise Products GP	$ 5.8
Incentive earnings allocation to Enterprise Products GP	$ 46.1
Standard earnings allocation to Enterprise Products GP	5.8
General partner interest in pro forma net income	$ 51.9
Pro forma net income	$ 335.4
Less general partner interest in pro forma net income	(51.9)
Pro forma net income available to limited partners	$ 283.5
Basic earnings per unit, net of general partner interest:	
As reported basic units outstanding	265.4
Pro forma basic units outstanding	378.8
As reported basic net income per unit	$ 0.87
Pro forma basic net income per unit	$ 0.75
Diluted earnings per unit, net of general partner interest:	
As reported diluted units outstanding	266.0
Pro forma diluted units outstanding	379.4
As reported diluted net income per unit	$ 0.87

Pro forma diluted net income per unit	$	0.75

13. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets at the dates indicated:

		At December 31, 2005		At December 31, 2004	
	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:					
Shell Processing Agreement	$ 206,216	$ (56,157)	$ 150,059	$ (45,110)	$ 161,106
STMA and GulfTerra NGL Business customer relationships (1)	49,784	(7,829)	41,955	(1,606)	48,004
Markham NGL storage contracts (1)	32,664	(5,444)	27,220	(1,088)	31,576
Toca-Western contracts	31,229	(5,595)	25,634	(4,033)	27,196
Indian Springs customer relationships	16,439	(1,954)	14,485		
Mont Belvieu storage contracts	8,127	(929)	7,198	(697)	7,430
Other	10,804	(1,577)	9,227	(601)	7,651
Segment total	355,263	(79,485)	275,778	(53,135)	282,963
Onshore Natural Gas Pipelines & Services:					
San Juan Gathering System customer relationships (1)	331,311	(30,065)	301,246	(6,222)	325,089
Petal & Hattiesburg natural gas storage contracts (1)	100,499	(10,742)	89,757	(2,059)	98,440
Texas Intrastate pipeline customer relationships (1)	20,992	(2,538)	18,454	(531)	20,461
Other	4,996	(610)	4,386	(63)	2,277
Segment total	457,798	(43,955)	413,843	(8,875)	446,267
Offshore Pipelines & Services:					
Offshore pipeline & platform customer relationships(1)	205,845	(32,480)	173,365	(6,965)	198,880
Other	1,167		1,167		1,167
Segment total	207,012	(32,480)	174,532	(6,965)	200,047
Petrochemical Services:					
Mont Belvieu propylene fractionation contracts	53,000	(5,931)	47,069	(4,417)	48,583
Other	3,674	(1,270)	2,404	(791)	2,741
Segment total	56,674	(7,201)	49,473	(5,208)	51,324
Total all segments	$ 1,076,747	$ (163,121)	$ 913,626	$ (74,183)	$ 980,601

(1) Acquired in connection with the GulfTerra Merger in September 2004

The following table shows the amortization of our intangible assets by segment for the periods indicated:

	For Year Ended December 31, 2005	2004	2003
NGL Pipelines & Services	$ 26,350	$ 16,000	$ 12,977
Onshore Natural Gas Pipelines & Services	35,080	8,875	
Offshore Pipelines & Services	25,515	6,965	
Petrochemical Services	1,993	1,973	1,848
Total all segments	$ 88,938	$ 33,813	$ 14,825

Based on information currently available, we estimate that amortization expense associated with existing intangible assets will approximate $82.5 million in 2006, $77.2 million in 2007, $72.4 million in 2008, $67.5 million in 2009 and $63.7 million in 2010.

Our significant intangible assets can be classified into the following categories: (i) the Shell Processing Agreement, (ii) the intangible assets we acquired in connection with the GulfTerra Merger, and (iii) other customer relationships and contracts. The following is a description of these significant categories:

Shell Processing Agreement. The Shell Processing Agreement grants us the right to process Shell s (or its assignee s) current and future production within the state and federal waters of the Gulf of Mexico. We acquired this intangible asset in connection with our 1999 acquisition of certain of Shell s midstream energy assets located along the Gulf Coast. The value of the Shell Processing Agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term through 2019.

Intangible assets acquired in connection with GulfTerra Merger. We acquired customer relationship and contract-based intangible assets in connection with the GulfTerra Merger. The customer relationship intangible assets represent the exploration and production, natural gas processing and NGL fractionation customer bases served by the GulfTerra and South Texas midstream assets at the time the merger was completed. The contract-based intangible assets represent the rights we acquired in connection with discrete contracts that GulfTerra had entered into to provide storage services for natural gas and NGLs.

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 third-party reserve estimates, the economic viability of production and exploration activities and other industry factors. This group of intangible assets primarily consists of the (i) Offshore Pipelines & Platforms customer relationships; (ii) San Juan Gathering System customer relationships; (iii) Texas Intrastate pipeline customer relationships; and (v) STMA and GulfTerra NGL Business customer relationships.

The contract-based intangible assets are being amortized over the estimated useful life (or term) of each agreement, which we estimate to range from two to eighteen years. This group of intangible assets consists of the (i) Petal and Hattiesburg natural gas storage contracts and (ii) Markham NGL storage contracts.

Other significant customer relationship and contract-based intangible assets. In January 2005, we acquired customer relationship intangible assets in connection with our purchase of indirect ownership interests in the Indian Springs natural gas gathering pipelines and processing assets. We are amortizing these intangible assets over a 19-year period, which is the expected life of the customers underlying resource bases.

In 2002, we acquired contract-based intangible assets in connection with the purchase of (i) a propylene fractionation facility and underground NGL and petrochemical storage caverns located in Mont Belvieu, Texas and (ii) a natural gas processing and NGL fractionation facility located in Louisiana (the Toca-Western contracts). In general, the values assigned to these intangible assets are being amortized on a straight-line basis over the estimated remaining economic life of underlying assets to which they relate, which ranged from 20 to 35 years at inception.

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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. Goodwill is not amortized; however, it is subject to annual impairment testing. The following table summarizes our goodwill amounts by segment at the dates indicated:

	At December 31, 2005	At December 31, 2004
NGL Pipelines & Services		
GulfTerra Merger	$ 23,927	$ 24,026
Acquisition of Indian Springs natural gas processing assets	13,180	
Other	17,853	8,737
Onshore Natural Gas Pipelines & Services		
GulfTerra Merger	280,812	290,397
Acquisition of Indian Springs natural gas gathering assets	2,185	
Offshore Pipelines & Services		
GulfTerra Merger	82,386	62,348
Petrochemical Services		
Acquisition of Mont Belvieu propylene fractionation assets	73,690	73,690
Totals	$ 494,033	$ 459,198

The goodwill resulting from 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 would develop (such as reduced general and administrative costs and interest savings) that could improve financial results of the merged entities. Based on miles of pipelines, GulfTerra was one of the largest natural gas gathering and transportation companies serving producers in the central and western Gulf of Mexico and onshore in Texas and New Mexico. These regions, especially the deepwater regions of the Gulf of Mexico, offer us significant growth potential through the acquisition and construction of additional pipelines, platforms, processing and storage facilities and other midstream energy infrastructure.

The remainder of our goodwill amounts are associated with prior acquisitions, principally that of our purchase of propylene fractionation assets in February 2002. We also recorded goodwill in connection with our acquisition of indirect ownership interests in the Indian Springs natural gas gathering and processing assets in January 2005.

14. Debt Obligations

Our consolidated debt consisted of the following at the dates indicated:

	December 31, 2005	December 31, 2004
Operating Partnership debt obligations:		
364-Day Acquisition Credit Facility, variable rate, repaid in February 2005 (1)		$ 242,229
Multi-Year Revolving Credit Facility, variable rate, due October 2010	$ 490,000	321,000
Seminole Notes, 6.67% fixed-rate, repaid December 2005		15,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes A, 8.25% fixed-rate, repaid March 2005		350,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes E, 4.00% fixed-rate, due October 2007	500,000	500,000
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	500,000
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	650,000
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	350,000
Senior Notes I, 5.00% fixed-rate, due March 2015 (2)	250,000	
Senior Notes J, 5.75% fixed-rate, due March 2035 (3)	250,000	
Senior Notes K, 4.950% fixed-rate, due June 2010 (4)	500,000	
Dixie Revolving Credit Facility, variable rate, due June 2007	17,000	
Debt obligations assumed from GulfTerra	5,068	6,469
Total principal amount	4,866,068	4,288,698
Other, including unamortized discounts and premiums and changes in fair value (5)	(32,287)	(7,462)
Subtotal long-term debt	4,833,781	4,281,236
Less current maturities of debt (6)		(15,000)
Long-term debt	$4,833,781	$4,266,236
Standby letters of credit outstanding	$ 33,129	$ 139,052

(1) We used the proceeds from our February 2005 common unit offering to fully repay and terminate the 364-Day Acquisition Credit Facility. For additional information regarding this equity offering, see Note 15.

(2) Senior Notes I were issued at 99.379% of their face amount in February 2005.

(3) Senior Notes J were issued at 98.691% of their face amount in February 2005.

(4) Senior Notes K were issued at 99.834% of their face amount in June 2005.

(5)

The December 31, 2005 amount includes $18.2 million related to fair value hedges and $14.1 million in net unamortized discounts. The December 31, 2004 amount includes $1.8 million related to fair value hedges and $9.2 million in net unamortized discounts.

(6) In accordance with SFAS No. 6, *Classification of Short-Term Obligations Expected to Be Refinanced*, long-term and current maturities of debt at December 31, 2004, reflected (i) our refinancing of Senior Notes A with proceeds from our Senior Notes I and J in March 2005 and (ii) the repayment of our 364-Day Acquisition Facility using proceeds from an equity offering completed in February 2005.

Letters of credit

At December 31, 2005, we had $33.1 million in standby letters of credit outstanding, which were issued under our Multi-Year Revolving Credit Facility. At December 31, 2004, we had $139.1 million of standby letters of credit outstanding, of which $115.1 million were issued under a letter of credit facility associated with our Independence Trail capital project. The decrease in letters of credit outstanding since 2004 is primarily due to the expiration of the Independence Trail letter of credit facility in October 2005.

Parent-Subsidiary guarantor relationships

At December 31, 2005, we act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Dixie revolving credit facility and the senior subordinated notes of GulfTerra. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation.

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Our Operating Partnership s senior indebtedness is structurally subordinated to and ranks junior in right of payment to the indebtedness of GulfTerra and Dixie. This subordination feature exists only to the extent that the repayment of debt incurred by GulfTerra and Dixie is dependent upon the assets and operations of these two entities. The Dixie revolving credit facility is an unsecured obligation of Dixie (of which we own 65.9% of its capital stock). The senior subordinated notes of GulfTerra are unsecured obligations of GulfTerra (of which we own 100% of its limited and general partnership interests).

Operating Partnership debt obligations

364-Day Acquisition Credit Facility. In August 2004, our Operating Partnership entered into a $2.25 billion 364-Day Acquisition Credit Facility, which was used to provide interim financing for certain purchase transactions associated with the GulfTerra Merger and the refinancing of substantially all of GulfTerra s then outstanding debt. We repaid approximately $2 billion of this indebtedness in October 2004 using proceeds from our issuance of Senior Notes E, F, G and H. In February 2005, we repaid the remaining balance using proceeds from our February 2005 common unit offering and terminated the facility.

Multi-Year Revolving Credit Facility. In August 2004, our Operating Partnership entered into a five-year multi-year revolving credit agreement in connection with the completion of the GulfTerra Merger. In October 2005, the borrowing capacity under this credit agreement was increased from $750 million to $1.25 billion, with the possibility that the borrowing capacity could be further increased to $1.4 billion (subject to certain conditions). In addition, the maturity date for debt outstanding under the facility was extended from September 2009 to October 2010. The Operating Partnership may make up to two requests for one-year extensions of the maturity date (subject to certain conditions). There is no limit on the amount of standby letters of credit that can be outstanding under the amended facility.

The Operating Partnership s borrowings under this agreement are unsecured general obligations that are non-recourse to Enterprise Products GP. 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 generally bear interest, at our election at the time of each borrowing, at (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus $^{1}/2\%$ or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate.

This revolving credit agreement contains various covenants related to our ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires us to satisfy certain financial covenants at the end of each fiscal quarter. The Multi-Year Revolving Credit Facility restricts the Operating Partnership 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.

Seminole Notes. Seminole Pipeline Company (Seminole), a majority-owned subsidiary, made the final $15 million payment on its indebtedness in December 2005.

Pascagoula MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, the Operating Partnership 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 the Operating Partnership s credit rating by Moody s declines below Baa3 in combination with our credit rating at Standard & Poor s remaining at BB+ or lower, the $54 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.

Senior Notes A through K. These fixed-rate notes are unsecured obligations of our Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. The Operating Partnership s borrowings under these notes are non-recourse to Enterprise Products GP. 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 Enterprise Products GP.

Senior Notes A through D are subject to make-whole redemption rights and were issued under an indenture containing certain covenants. These covenants restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. The remainder of the Senior Notes (E through K) are also subject to similar covenants.

Senior Notes E, F, G, and H were issued as private placement debt in September 2004 and generated an aggregate $2 billion in proceeds, which were used to repay amounts borrowed under the 364-Day Acquisition Credit Facility. Senior Notes E through H were exchanged for registered debt securities in March 2005.

Senior Notes I and J were issued as private placement debt in February 2005 and generated an aggregate $500 million in proceeds, which were used to repay $350 million due under Senior Notes A (which matured in March 2005) and the remainder for general partnership purposes, including the temporary repayment of amounts then outstanding under the Multi-Year Revolving Credit Facility. Senior Notes I and J were exchanged for registered debt securities in August 2005.

Senior Notes K were issued as registered securities in June 2005 and generated $500 million in proceeds, which were used for general partnership purposes, including the temporary repayment of amounts then outstanding under the Multi-Year Revolving Credit Facility. Senior Notes K were issued under the $4 billion universal shelf registration statement we filed in March 2005 (see Note 15).

Dixie Revolving Credit Facility

As a result of acquiring a controlling interest in Dixie in February 2005, we began consolidating the financial statements of Dixie with those of our own. Dixie s debt obligations consist of a senior unsecured revolving credit facility having a borrowing capacity of $28 million.

As defined by the credit agreement, variable interest rates charged under this facility generally bear interest, at our 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 Rate by $^{1}/2\%$.

This revolving credit agreement contains various covenants related to Dixie s ability to incur certain indebtedness; grant certain liens; enter into merger transactions; and make certain investments. The loan agreement also requires Dixie to satisfy a minimum net worth financial covenant. The revolving credit agreement restricts Dixie s ability to pay cash dividends to us and its other stockholders if a default or an event of default (as defined in the credit agreement) has occurred and its continuing at the time such dividend is scheduled to be paid.

Debt Obligations assumed from GulfTerra

Senior and Senior Subordinated Notes. Upon completion of the GulfTerra Merger, we recorded in consolidation $921.5 million of GulfTerra s then outstanding senior and senior subordinated notes. Of this amount, $915 million was purchased by our Operating Partnership in October 2004 pursuant to its tender offers for such debt. The Operating Partnership financed these purchases using borrowings under its 364-Day Acquisition Credit Facility. The noteholders also approved (as a condition to accepting the tender offers) amendments that removed all restrictive covenants governing the GulfTerra notes.

At December 31, 2004, $6.5 million in principal amount of these obligations remained outstanding. During 2005, we redeemed an additional $1.4 million of this assumed debt. The $5.1 million in principal remaining outstanding at December 31, 2005 bears fixed-rate interest of 8.5% and matures in June 2010.

Petal Industrial Development Revenue Bonds. In April 2004, Petal Gas Storage L.L.C. (Petal), one of our wholly owned subsidiaries, borrowed $52 million from the MBFC. Concurrently, the MBFC sold $52 million in Industrial Development Bonds to another of our wholly owned subsidiaries. Petal had the option to repay its MBFC loan without penalty, and thus cause the Industrial Development Revenue Bonds to be redeemed, any time after one year from their date of issue. In August 2005, Petal exercised its option to repay the loan agreement and the $52 million in Industrial Development Bonds were redeemed and retired.

Prior to redemption, we netted the Petal MBFC loan payable against the Industrial Development Bonds receivable and also the related interest payable and receivable amounts on our balance sheet. Additionally, we netted the interest expense and interest income amounts attributable to these instruments on our statements of consolidated operations. This presentation was in accordance with the provisions of FIN 39, *Offsetting of Amounts Related to Certain Contracts*, and SFAS 140, "*Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, since we had the ability and intent to offset these items.

Covenants

We are in compliance with the covenants of our consolidated debt agreements at December 31, 2005 and 2004.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our significant consolidated variable-rate debt obligations during 2005.

	Range of interest rates paid	**Weighted-average interest rate paid**
364-Day Acquisition Credit Facility	3.25% to 3.40%	3.35%
Multi-Year Revolving Credit Facility	3.22% to 7.00%	4.25%
Dixie Revolving Credit Facility	3.66% to 4.67%	4.12%

Consolidated debt maturity table

The following table presents the scheduled maturities of principal amounts of our debt obligations for the next 5 years and in total thereafter.

2006	None.
2007	$ 517,000
2008	None.
2009	500,000
2010	1,049,068
Thereafter	2,800,000
Total scheduled principal payments	$ 4,866,068

Joint venture debt obligations

We have three unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at December 31, 2005, (ii) total debt of each unconsolidated affiliate at December 31, 2005, on a 100% basis to the joint venture, and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	Total	Scheduled Maturities of Debt 2006	2007	2008	2009	2010	After 2010
Cameron Highway	50.0%	$415,000			$ 25,000	$25,000	$50,000	$315,000
Poseidon	36.0%	95,000			95,000			
Evangeline	49.5%	30,650	$5,000	$5,000	5,000	5,000	10,650	
Total		$540,650	$5,000	$5,000	$125,000	$30,000	$60,650	$315,000

The credit agreements of our joint ventures contain various affirmative and negative covenants, including financial covenants. Our joint ventures were in compliance with all such covenants at December 31, 2005. The credit agreements of our joint ventures restrict their ability to pay cash dividends if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend is scheduled to be paid.

In March 2005, we contributed $72 million to Deepwater Gateway to assist in the repayment of its $144 million term loan. Our joint venture partner in Deepwater Gateway also contributed $72 million. Deepwater Gateway used funds borrowed under its term loan to fund a substantial portion of the cost to construct the Marco Polo platform and related facilities.

The following information summarizes significant terms of the debt obligations of our unconsolidated affiliates at December 31, 2005:

Cameron Highway. In July 2003, Cameron Highway entered into a $325 million project loan facility to finance a substantial portion of the cost to construct its crude oil pipeline. In June 2005, Cameron Highway executed a new term loan agreement with a total credit commitment of $415 million and borrowed the full amount, which was used to repay principal amounts outstanding under the project loan facility and to make $95 million in cash distributions to its partners. We received a partial return of our investment in Cameron Highway of $47.5 million in connection with this special distribution. In connection with this refinancing, Cameron Highway incurred $22 million in one-time cash make-whole premiums and related fees and non-cash charges.

In December 2005, Cameron Highway issued $415 million of private placement, non-recourse senior secured notes due December 2017. Proceeds from the issuance of these senior secured notes were used to repay the $415 million term loan that Cameron Highway entered into during June 2005. The senior secured notes were issued in two series $365 million of Series A notes, which have a fixed-rate interest of 5.86%, and $50 million of Series B notes, which have a variable-rate interest based on a Eurodollar rate plus 1%. At December 31, 2005, the variable interest rate charged under the Series B notes was 4.52%.

The notes are secured by (i) mortgages on and pledges of substantially all of the assets of Cameron Highway, (ii) mortgages on and pledges of certain assets related to certain rights of way and pipeline assets of an indirect wholly-owned subsidiary of ours that serves as the operator of the Cameron Highway Oil Pipeline, (iii) pledges by us and our joint venture partner in Cameron Highway of our 50% partnership interests in Cameron Highway, and (iv) letters of credit in an initial amount of $18.4 million each issued by our Operating Partnership and an affiliate of our joint venture partner. Except for the foregoing, the noteholders do not have any recourse against our assets or any of our subsidiaries under the note purchase agreement.

Poseidon. Poseidon has entered into a $170 million revolving credit facility that matures in January 2008. The interest rates charged under this revolving credit facility are variable and depend on the ratio of Poseidon s total debt to its earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon s assets. The variable interest rates charged on this debt at December 31, 2005 and 2004 were 5.34% and 4.58%, respectively.

Evangeline. At December 31, 2005, long-term debt for Evangeline consisted of (i) $23.2 million in principal amount of 9.9% 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 million annually through 2009 with a final repayment in 2010 of approximately $3.2 million. The trust indenture governing the Series B notes contains covenants such as requirements to maintain certain financial ratios.

Evangeline incurred the subordinated note payable as a result of its acquisition of a contract-based intangible asset in the 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the note until such time as the Series B note holders 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 $^1/2$%. The variable interest rates charged on this note at December 31, 2005 and 2004 were 3.58% and 1.73%, respectively. Accrued interest payable related to the subordinated note was $7.1 million and $6.6 million at December 31, 2005 and 2004.

15. Partners Equity

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, Enterprise Products GP.

Capital Accounts

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our consolidated financial statements.

Our Partnership Agreement sets forth the calculation 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. See Note 16 for information regarding our cash distributions to partners, including incentive cash distributions to Enterprise Products GP.

In August 2005, we revised our Partnership Agreement to allow Enterprise Products GP, 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 would be proportionately reduced. Historically, Enterprise Products GP has contributed cash to us (at the time of these offerings) to maintain its 2% general partner interest in us. Enterprise Products GP made such cash contributions to us during 2005. If Enterprise Products GP 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, Enterprise Products GP 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 Enterprise Products GP in its sole discretion (subject, under certain circumstances, to the approval of our unitholders). We completed a number of common unit offerings in 2005, 2004 and 2003.

The following table reflects the number of common units issued and the net proceeds received from these offerings:

		Net Proceeds			
	Number of common units issued	Contributed by Limited Partners	Contributed by General Partner	Contributed by General Partner in Minority Interest [1]	Total
Fiscal 2003:					
Underwritten Offerings [2]	26,622,500	$508,833	$ 5,139	$ 5,247	$519,219
Other Offerings [3]	2,883,803	59,112	600	614	60,326
Total 2003	29,506,303	$567,945	$ 5,739	$ 5,861	$579,545
Fiscal 2004:					
Underwritten Offerings [4]	34,500,000	$680,390	$ 13,886		$694,276
Other Offerings [3]	5,183,591	109,368	2,231		111,599
Total 2004	39,683,591	$789,758	$ 16,117		$805,875
Fiscal 2005:					
Underwritten Offerings:					
February 2005 [5]	17,250,000	$447,602	$ 9,135		$456,737
December 2005 [6]	4,000,000	96,745	1,974		98,719
Other Offerings: [3]					
February 2005	1,516,561	38,249	780		39,029
May 2005	410,249	10,204	208		10,412
August 2005	399,812	9,934	204		10,138
November 2005	403,118	9,882	201		10,083
Total 2005	23,979,740	$612,616	$ 12,502		$625,118

(1) Prior to the restructuring of Enterprise Products GP s ownership interest in December 2003, Enterprise Products GP owned 1.0101% of the Operating Partnership. This ownership interest was accounted for as a component of minority interest in our historical Consolidated Balance Sheets.

(2) We used the proceeds from these public offerings to repay a portion of the indebtedness under the Operating Partnership s 364-Day Term Loan we entered into to fund the Mid-America and Seminole acquisitions in July 2002, to reduce indebtedness outstanding under the Operating Partnership s revolving credit facilities and for

general partnership purposes.

(3) These units were issued primarily in connection with our distribution reinvestment plan (DRIP). We used the proceeds from these offerings primarily for general partnership purposes.

(4) We used the proceeds from these public offerings to (i) repay the Operating Partnership s $225 million Interim Term Loan related to the GulfTerra Merger, (ii) temporarily reduce borrowings outstanding under its revolving credit facilities, and (iii) partially fund our payment obligations to El Paso under Step Two of the GulfTerra Merger.

(5) We used the proceeds from this offering to repay the remaining amounts due under the Operating Partnership s 364-Day Acquisition Credit Facility and to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility.

(6) We used the proceeds from this offering to temporarily reduce borrowings outstanding under the Operating Partnership s Multi-Year Revolving Credit Facility.

In March 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of equity and debt securities. After taking into account our issuance of securities under this universal registration statement during 2005, we can issue an additional $3.4 billion of securities under this registration statement as of December 31, 2005.

During 2003, we instituted a distribution reinvestment plan (DRIP). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can

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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. We have a registration statement on file with the SEC covering the issuance of up to 15,000,000 common units in connection with the DRIP. A total of 10,539,148 common units have been issued under this registration statement through December 31, 2005.

We also 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. A total of 227,986 common units have been issued to employees under this plan through December 31, 2005.

Common Units issued in connection with the GulfTerra Merger

Under Step Two of the GulfTerra Merger (see Note 12), we issued 1.81 of our common units for each GulfTerra common unit (including restricted common units) remaining after our purchase of 2,876,620 GulfTerra common units owned by El Paso. The number of units we issued in connection with this conversion was calculated as follows:

GulfTerra units outstanding at September 30, 2004:		
Common units, including time-vested restricted common units		60,638,989
Series C units		10,937,500
Total historical units outstanding at September 30, 2004		71,576,489
Adjustments to GulfTerra historical units outstanding as a result of the GulfTerra Merger:		
Purchase of GulfTerra Series C units from El Paso in connection with Step Two		(10,937,500)
Purchase of GulfTerra common units from El Paso in connection with Step Two		(2,876,620)
GulfTerra common units outstanding subject to Step Two exchange offer		57,762,369
Conversion ratio (1.81 of our common units for each GulfTerra common unit)		1.81
Common units issued to GulfTerra common unitholders in connection with GulfTerra Merger (adjusted for 65 fractional common units)		104,549,823
Average closing price per unit of our common units immediately prior to and after proposed GulfTerra Merger was announced on December 15, 2003	$	23.39
Fair value of our common units issued in conversion of remaining GulfTerra common units	$	2,445,420

In accordance with purchase accounting, the $2.4 billion value of our common units was based on the average closing price of our common units immediately prior to and after the proposed merger was announced on December 15, 2003.

Overall, the fair value of equity interests we issued on September 30, 2004 under Step Two of the GulfTerra Merger was approximately $2.9 billion. The following table presents the detail for this consideration:

Fair value of common units issued in conversion of remaining GulfTerra common units	$	2,445,420
Fair value of equity interests issued to acquire the remaining 50% membership interest in GulfTerra GP (voting interest) [1]		461,347
Fair value of other equity interests issued for unit awards and Series F2 convertible units		4,005
Total value of equity interests issued upon closing of GulfTerra Merger	$	2,910,772

(1) This fair value is based on 50% of an implied $922.7 million total value of GulfTerra GP, which assumes that the $370 million cash payment made by Enterprise Products GP to El Paso in Step Two represented consideration for a 40.1% interest in GulfTerra GP. The 40.1% interest was derived by deducting the 9.9% membership interest in

Enterprise Products GP granted to El Paso in this transaction from the 50% membership interest in GulfTerra GP that Enterprise Products GP received. The fair value of $461.3 million assigned to this voting membership interest in GulfTerra GP compares favorably to the $425 million we paid El Paso in December 2003 to purchase our initial 50% non-voting membership interest in GulfTerra GP. The contribution of this 50% membership interest to Enterprise Products Partners is allocated for financial reporting purposes to our limited partners and general partner based on the respective ownership percentages and the related allocation of profits and losses of 98% and 2%, respectively, both of which are consistent with the Partnership Agreement.

As a result of the GulfTerra Merger, we assumed GulfTerra s obligation associated with its 80 Series F2 convertible units. All Series F2 convertible units outstanding at the merger date were converted into rights to receive our common units based on the 1.81 exchange ratio. In 2004, all of the convertible units were exercised and we issued 1,950,317 common units and received net proceeds of $40 million.

Class B special units

In December 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO for $100 million. After receiving the approval of our unitholders, we converted the Class B special units into an equal number of common units in July 2004.

Subordinated units and Class A special units issued to Shell

We issued subordinated units and Class A special units to Shell in connection with our acquisition of certain midstream energy assets in 1999. Both classes of units converted to common units over a period of time extending into 2003. The conversion of subordinated units in 2003 had no impact on our earnings per unit or cash distributions since subordinated units were included in both the basic and fully diluted earnings per unit calculations and were distribution bearing. The conversion of Class A special units in 2003 had a dilutive impact on basic earnings per unit since they increased the number of common units used in the computation. Class A special units were excluded from the computation of basic earnings per unit because they did not share in income or loss nor were they entitled to cash distributions until they were converted to common units.

Treasury units

In 2000, we and a consolidated trust (the 1999 Trust) were authorized by Enterprise Products GP 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, 2005. Common units repurchased under the program are accounted for in a manner similar to treasury stock under the cost method of accounting. For the purpose of calculating both basic and diluted earnings per unit, treasury units are not considered to be outstanding. We reissued 371,113 units and 30,887 units out of treasury in 2004 and 2003, respectively, in connection with the exercise of unit options by employees of EPCO. We retired 30,000 treasury units in 2003 and cancelled the remaining 427,200 treasury units in 2005.

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Summary of Limited Partner Transactions since 2002

The following table details the changes in limited partners equity since December 31, 2002:

	Common units	Restricted Common units	Subordinated units	Class A Special units	Class B Special units	Total
Balance, December 31, 2002	$ 949,835		$ 116,288	$ 143,926		$ 1,210,049
Net income	73,075		10,566		$ 176	83,817
Operating leases paid by EPCO	8,154		751		8	8,913
Other expenses paid by EPCO	435				(2)	433
Cash distributions to partners	(254,111)		(30,482)			(284,593)
Unit option reimbursements to EPCO	(2,721)					(2,721)
Conversion of 10 million Class A special units to common units	143,926			(143,926)		
Conversion of 10.7 million subordinated units to common units	97,123		(97,123)			
Net proceeds from sales of common units	567,945					567,945
Proceeds from issuance of Class B special units					100,000	100,000
Restructuring of Enterprise Products GP ownership in our Operating Partnership	(73)					(73)
Treasury unit transactions:						
Reissued to satisfy unit options	6					6
Retired	(643)					(643)
Balance, December 31, 2003	1,582,951				100,182	1,683,133
Net income	229,016	$ 142			1,995	231,153
Operating leases paid by EPCO	7,449	2			100	7,551
Cash distributions to partners	(390,928)	(218)			(3,288)	(394,434)
Unit option reimbursements to EPCO	(3,813)					(3,813)
Net proceeds from sales of common units	789,758					789,758

Proceeds from conversion of Series F2 convertible units to common units	38,800					38,800
Proceeds from exercise of unit options	398					398
Conversion of Class B special units to common units	98,993				(98,993)	
Value of equity interests granted to complete the GulfTerra Merger	2,851,796	2,479				2,854,275
Other issuance of restricted units		9,922				9,922
Treasury units reissued to satisfy unit options	520				4	524
Balance, December 31, 2004	5,204,940	12,327				5,217,267
Net income	347,948	564				348,512
Operating leases paid by EPCO	2,067	3				2,070
Cash distributions to partners	(629,629)	(931)				(630,560)
Unit option reimbursements to EPCO	(9,199)					(9,199)
Net proceeds from sales of common units	612,616					612,616
Proceeds from exercise of units options	21,374					21,374
Issuance of restricted units		9,478				9,478
Vesting of restricted units	143	(143)				
Forfeiture of restricted units		(2,663)				(2,663)
Amortization of Employee Partnership awards	1,355	3				1,358
Cancellation of treasury units	(8,915)					(8,915)
Balance, December 31, 2005	$ 5,542,700	$ 18,638	$	$	$	$ 5,561,338

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Unit History

The following table details the outstanding balance of each class of units for the periods and at the dates indicated:

	Limited Partners					
	Common Units	Restricted Common Units	Subordinated Units	Class A Special Units	Class B Special Units	Treasury Units
Balance, December 31, 2002	141,694,766		32,114,804	10,000,000		859,200
Common units issued in connection with 2003 offerings	29,526,948					
Conversion of subordinated units to common units in May 2003	10,704,936		(10,704,936)			
Conversion of Class A special units to common units in August 2003	10,000,000			(10,000,000)		
Conversion of subordinated units to common units in August 2003	21,409,868		(21,409,868)			
Class B special units issued in December 2003					4,413,549	
Treasury unit transactions:						
Reissued to satisfy unit options	30,242					(30,887)
Retired						(30,000)
Balance, December 31, 2003	213,366,760				4,413,549	798,313
Common units issued in connection with 2004 offerings	39,700,078					
Conversion of Class B special units to common units in July 2004	4,413,549				(4,413,549)	
Common and restricted common units issued to GulfTerra unitholders on September 30, 2004	104,495,523	54,300				

in connection with the GulfTerra Merger			
Common units issued in connection with conversion of Series F2 units in October and November 2004	1,950,317		
Other restricted common units issued in 2004		434,225	
Treasury units reissued to satisfy unit options	371,113		(371,113)
Balance, December 31, 2004	364,297,340	488,525	427,200
Common units issued in connection with February 2005 offering	17,250,000		
Other common units issued in February 2005	1,516,561		
Restricted common units issued in February 2005		12,892	
Common units issued in March 2005 in connection with units options	195,000		
Vesting of restricted units in April 2005	6,484	(6,484)	
Cancellation of treasury units in April 2005			(427,200)
Common units issued in May 2005	410,249		
Restricted common units issued in May 2005		269	
Common units issued in May 2005 in connection with units options	525,000		
Common units issued in August 2005	399,812		
Restricted common units issued in August 2005		316,425	
Common units issued in August 2005 in	71,000		

connection with units options		
Restricted common units forfeited in August 2005		(60,427)
Restricted common units forfeited in October 2005		(2,000)
Common units issued in connection with November 2005 offering	4,000,000	
Common units issued in November 2005	403,118	
Restricted common units issued in November 2005		32,425
Common units issued in November 2005 in connection with units options	35,000	
Restricted common units forfeited in November 2005		(30,021)
Balance, December 31, 2005	389,109,564	751,604

Accumulated Other Comprehensive Income (Loss)

The following table summarizes transactions affecting our accumulated other comprehensive income (loss) since December 31, 2002.

	Commodity Financial Instruments	Interest Rate Fin. Instrs. Treasury Locks	Forward-Starting Interest Rate Swaps	Accumulated Other Comprehensive Income (Loss) Balance
Balance, December 31, 2002		$ (3,560)		$ (3,560)
Reclassification of change in fair value of treasury locks		3,560		3,560
Gain on settlement of treasury locks		5,354		5,354
Reclassification of gain on settlement of treasury locks to interest expense		(364)		(364)
Balance, December 31, 2003		4,990		4,990
Gain on settlement of forward-starting interest rate swaps			$ 104,531	104,531
Loss on settlement of forward-starting interest rate swaps			(85,126)	(85,126)
Change in fair value of commodity financial instrument	$ 1,434			1,434
Reclassification of gain on settlement of interest rate financial instruments		(418)	(857)	(1,275)
Balance, December 31, 2004	1,434	4,572	18,548	24,554
Change in fair value of commodity financial instruments	(1,434)			(1,434)
Reclassification of gain on settlement of interest rate financial instruments		(445)	(3,603)	(4,048)
Balance, December 31, 2005	$	$ 4,127	$ 14,945	$ 19,072

During the first quarter of 2005, we reclassified into income a $1.4 million gain related to a commodity cash flow hedge we acquired in connection with the GulfTerra Merger. This gain resulted from an increase in fair value of the underlying financial instrument from the value recorded for the commodity cash flow hedge at September 30, 2004. In 2006, we expect to reclassify $4.3 million of accumulated other comprehensive income that was generated by treasury lock and forward-starting interest rate swap transactions to reduce interest expense.

16. Distributions to Partners

We expect, to the extent there is sufficient cash available from Operating Surplus (as defined by our Partnership Agreement) to distribute to each holder of common units at least a minimum quarterly distribution of $0.225 per common unit. The minimum quarterly distribution is not guaranteed and is subject to adjustment as set forth in the Partnership Agreement.

As an incentive, Enterprise Products GP s percentage interest in our quarterly cash distributions is increased after certain specified target levels of distribution rates are met. Enterprise Products GP 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 to Enterprise Products GP of $63.9 million, $32.4 million and $19.7 million in 2005, 2004 and 2003, respectively.

The following table presents our quarterly cash distribution rates per unit paid to common unitholders since the first quarter of 2003 and the related record and distribution payment dates.

	Cash Distribution History		
	Distribution per Unit(1)	Record Date	Payment Date
2003			
1st Quarter	$ 0.3625	Apr. 30, 2003	May 12, 2003
2nd Quarter	$ 0.3625	Jul. 31, 2003	Aug. 11, 2003
3rd Quarter	$ 0.3725	Oct. 31, 2003	Nov. 12, 2003
4th Quarter	$ 0.3725	Jan. 30, 2004	Feb. 11, 2004
2004			
1st Quarter	$ 0.3725	Apr. 30, 2004	May 12, 2004
2nd Quarter	$ 0.3725	Jul. 30, 2004	Aug. 6, 2004
3rd Quarter	$ 0.3950	Oct. 29, 2004	Nov. 5, 2004
4th Quarter	$ 0.4000	Jan. 31, 2005	Feb. 14, 2005
2005			
1st Quarter	$ 0.4100	Apr. 29, 2005	May 10, 2005
2nd Quarter	$ 0.4200	Jul. 29, 2005	Aug. 10, 2005
3rd Quarter	$ 0.4300	Oct. 31, 2005	Nov. 8, 2005
4th Quarter	$ 0.4375	Jan. 31, 2006	Feb. 9, 2006

(1) Distributions are paid on common units, and prior to their conversion to common units, on subordinated units and Class B special units as well.

The quarterly cash distribution rates per unit shown in the preceding table correspond to the cash flows for the quarters indicated. The actual cash distributions are paid within 45 days after the end of such quarter.

17. Business Segments

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technology 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 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 (or consolidated) segment gross operating margin as operating income before: (i) depreciation and amortization expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses on the sale of assets; and (iv) general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principles. 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 and operating costs and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of all material intercompany (both intersegment and intrasegment) transactions.

We have historically included equity earnings from 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, which may be suppliers of raw materials or consumers of finished products. 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 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 and petrochemicals. Our asset system has multiple entry points. In general, hydrocarbons can enter our asset system through a number of ways, including an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an NGL gathering pipeline, an NGL fractionator, an NGL storage facility, an NGL transportation or distribution pipeline or an onshore natural gas pipeline. At each link along this asset system, we earn revenues based on volume or an ownership of products such as NGLs.

Many of our equity investees are present within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process NGLs extracted by our gas plants. The NGLs received from Promix then can be sold in our NGL marketing activities. Given the integral nature of our equity investees to our operations, we believe treatment of earnings from our equity method investees as a component of gross operating margin and operating income is appropriate.

Our consolidated revenues were earned in the United States and derived from a wide customer base. Currently, our plant-based operations are located primarily in Texas, Louisiana, Mississippi and New Mexico. Our natural gas, NGL and crude oil pipelines are in a number of regions of the United States including the Gulf of Mexico offshore Texas and Louisiana; the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and certain regions of the central and western United States. Our marketing activities are headquartered in Houston, Texas 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 and advances to unconsolidated affiliates are allocated to each segment on the basis of each asset s or investment s principal operations. The principal reconciling item between consolidated property, plant and equipment and the total value of segment assets is construction-in-progress. Segment assets represent the net carrying value of facilities and projects that contribute to the gross operating margin of a particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets are excluded from the segment asset totals until they are deemed operational. Consolidated intangible assets and goodwill are allocated to each segment based on the classification of the assets to which they relate.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

	Year Ended December 31, 2005	2004	2003
Revenues (1)	$ 12,256,959	$ 8,321,202	$ 5,346,431
Less: Operating costs and expenses (1)	(11,546,225)	(7,904,336)	(5,046,777)
Add: Equity in income (loss) of unconsolidated affiliates (1)	14,548	52,787	(13,960)
Depreciation and amortization in operating costs and expenses (2)	413,441	193,734	115,643
Retained lease expense, net in operating expenses allocable to us and minority interest (3)	2,112	7,705	9,094
Gain on sale of assets in operating costs and expenses (2)	(4,488)	(15,901)	(16)
Total segment gross operating margin	$ 1,136,347	$ 655,191	$ 410,415

(1) These amounts are taken from our Statements of Consolidated Operations and Comprehensive Income.

(2) These non-cash expenses are taken from the operating activities section of our Statements of Consolidated Cash Flows.

(3) These non-cash expenses represent the value of the operating leases contributed by EPCO to us for which EPCO has retained the cash payment obligation (i.e., the retained leases). The value of the retained leases contributed directly to us is shown on our Statements of Consolidated Cash Flows under the line item titled Operating lease expense paid by EPCO. That portion of the value contributed by a minority interest holder is a component of Contributions from minority interests as shown in the financing activities section of our Statements of Consolidated Cash Flows.

A reconciliation of our measurement of total segment gross operating margin to GAAP operating income and income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles follows:

	Year Ended December 31, 2005	2004	2003
Total segment gross operating margin	$ 1,136,347	$ 655,191	$ 410,415
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation and amortization in operating costs and expenses	(413,441)	(193,734)	(115,643)
Retained lease expense, net in operating costs and expenses	(2,112)	(7,705)	(9,094)
Gain on sale of assets in operating costs and expenses	4,488	15,901	16
General and administrative costs	(62,266)	(46,659)	(37,590)
Consolidated operating income	663,016	422,994	248,104
Other expense	(225,178)	(153,625)	(134,406)
Income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 437,838	$ 269,369	$ 113,698

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Information by segment, together with reconciliations to the consolidated totals, is presented in the following table:

	Operating Segments						
	Offshore Pipelines & Services	**Onshore Natural Gas Pipelines & Services**	**NGL Pipelines & Services**	**Petrochemical Services**	**Non-Segmt. Other**	**Adjustments and Eliminations**	**Consolidated Totals**
Revenues from third parties:							
Year ended December 31, 2005	$110,100	$1,198,320	$ 9,006,730	$1,587,037			$11,902,187
Year ended December 31, 2004	32,168	541,529	5,553,895	1,389,460			7,517,052
Year ended December 31, 2003		344,611	3,654,577	782,999			4,782,187
Revenues from related parties:							
Year ended December 31, 2005	696	337,282	16,689	105			354,772
Year ended December 31, 2004	535	253,194	534,279	16,142			804,150
Year ended December 31, 2003		227,973	325,377	10,894			564,244
Intersegment and intrasegment revenues:							
Year ended December 31, 2005	1,353	41,576	3,334,763	346,458		$(3,724,150)	
Year ended December 31, 2004	358	21,436	2,077,871	249,758		(2,349,423)	
Year ended December 31, 2003		3,975	1,143,595	186,672		(1,334,242)	
Total revenues:							
Year ended December 31, 2005	112,149	1,577,178	12,358,182	1,933,600		(3,724,150)	12,256,959
Year ended December 31, 2004	33,061	816,159	8,166,045	1,655,360		(2,349,423)	8,321,202
Year ended December 31, 2003		576,559	5,123,549	980,565		(1,334,242)	5,346,431
Equity in income (loss) in unconsolidated affiliates:							
Year ended December 31, 2005	6,125	2,384	5,553	486			14,548
	8,859	772	9,898	1,233	$32,025		52,787

Year ended December 31, 2004							
Year ended December 31, 2003	5,561	131	7,842	(27,441)	(53)		(13,960)
Gross operating margin by individual business segment and in total:							
Year ended December 31, 2005	77,505	353,076	579,706	126,060			1,136,347
Year ended December 31, 2004	36,478	90,977	374,196	121,515	32,025		655,191
Year ended December 31, 2003	5,561	18,345	310,677	75,885	(53)		410,415
Segment assets:							
At December 31, 2005	632,222	3,622,318	3,075,048	504,841		854,595	8,689,024
At December 31, 2004	648,181	3,729,650	2,753,934	469,327		230,375	7,831,467
Investments in and advances to unconsolidated affiliates (see Note 11):							
At December 31, 2005	316,844	4,644	130,376	20,057			471,921
At December 31, 2004	319,463	5,251	173,883	20,567			519,164
Intangible Assets (see Note 13):							
At December 31, 2005	174,532	413,843	275,778	49,473			913,626
At December 31, 2004	200,047	446,267	282,963	51,324			980,601
Goodwill (see Note 13):							
At December 31, 2005	82,386	282,997	54,960	73,690			494,033
At December 31, 2004	62,348	290,397	32,763	73,690			459,198

In general, our historical operating results and/or financial position have been affected by numerous acquisitions since 2002. Our most significant transaction to date was the GulfTerra Merger, which was completed in September 2004. The value of total consideration we paid or issued to complete the GulfTerra Merger was approximately $4 billion. The operating results of entities and assets we acquire are included in our financial results prospectively from their purchase dates.

Revenues from the sale and marketing of NGL products within the NGL Pipelines & Services business segment accounted for 67% of total consolidated revenues for each of 2005 and 2004 and 68% of total consolidated revenues for 2003. Revenues from the sale of petrochemical products within the Petrochemical Services segment accounted for 11%, 13% and 12% of total consolidated revenues for 2005, 2004 and 2003, respectively. Revenues from the transportation, sale and storage of natural gas using onshore assets accounted for 13%, 10% and 11% of total consolidated revenues for 2005, 2004 and 2003, respectively.

18. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For Year Ended December 31, 2005	2004	2003
Revenues from consolidated operations			
EPCO and affiliates	$ 311	$ 2,697	$ 4,241
Shell		542,912	293,109
Unconsolidated affiliates	354,461	258,541	266,894
Total	$ 354,772	$ 804,150	$ 564,244
Operating costs and expenses			
EPCO and affiliates	$ 293,134	$ 203,100	$ 149,915
Shell		725,420	607,277
Unconsolidated affiliates	23,563	37,587	43,752
Total	$ 316,697	$ 966,107	$ 800,944
General and administrative expenses			
EPCO and affiliates	$ 40,954	$ 29,307	$ 28,716

Historically, Shell was considered a related party because it owned more than 10% of our limited partner interests and, prior to 2003, held a 30% membership interest in Enterprise Products GP. As a result of Shell selling a portion of its limited partner interests in us to third parties, Shell owned less than 10% of our common units at the beginning of 2005. Shell sold its 30% interest in Enterprise Products GP to an affiliate of EPCO in September 2003. As a result of Shell s reduced equity interest in us and its lack of control of Enterprise Products GP, Shell ceased to be considered a related party in January 2005.

Relationship with EPCO and affiliates

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

§ EPCO and its private company subsidiaries;

§ Enterprise Products GP, our sole general partner;

§ Enterprise GP Holdings, which owns and controls our general partner;

§ the Employee Partnership; and

§ TEPPCO Partners, L.P. (TEPPCO) and its general partner (TEPPCO GP), which are controlled by affiliates of EPCO.

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

We were formed in 1998 to own and operate certain NGL assets contributed to us by EPCO. EPCO is a private company controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise Products GP. Mr. Duncan owns 50.4% of the voting stock of EPCO. The remaining shares of EPCO capital stock are held primarily by trusts for the benefit of members of Mr. Duncan s family.

At December 31, 2005, EPCO and its affiliates beneficially owned 144,055,494 (or 36.2%) of our outstanding common units. In January 2005, an affiliate of EPCO acquired 13,454,498 of our common units and a 9.9% membership interest in our general partner from El Paso for approximately $425 million in cash. As a result of this transaction and until August 2005, EPCO and certain of its affiliates owned 100% of the membership interests of our general partner and El Paso no longer owned any limited or general partner interest in us.

In August 2005, affiliates of EPCO contributed their 100% membership interests in our general partner and the 13,454,498 of our common units they acquired from El Paso to Enterprise GP Holdings, another affiliate of EPCO. As a result of this contribution, Enterprise GP Holdings owns 100% of the membership interests of our general partner and an approximate 3.4% limited partner interest in us. Enterprise GP Holdings is a publicly traded limited partnership that completed an initial public offering of its common units in August 2005, and its only cash generating assets consist of its general and limited partnership interests in us. At December 31, 2005, EPCO and its affiliates owned 86.5% of Enterprise GP Holdings, including 100% of EPE Holdings, LLC (EPE Holdings), the general partner of Enterprise GP Holdings.

The principal business activity of Enterprise Products GP is to act as our managing partner. The executive officers and certain of the directors of Enterprise Products GP and Enterprise GP Holdings are employees of EPCO. Apart from the rights it owns with respect to its general partner interest in us, Enterprise Products GP does not receive any compensation for its services to us as general partner. Enterprise Products GP received $76.8 million, $40.4 million and $25.7 million of cash distributions from us in connection with its general partner interest during 2005, 2004 and 2003, respectively. The foregoing distributions for 2005, 2004 and 2003 include $63.9 million, $32.4 million and $19.7 million of incentive distributions. See Note 16 for information regarding our distribution policy.

We and Enterprise Products GP are both separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from those of EPCO and its other affiliates. EPCO depends on the cash distributions it receives from us, Enterprise GP Holdings and other investments to fund its other operations and to meet its debt obligations. EPCO and its affiliates received $243.9 million, $189.8 million and $176.8 million in cash distributions from us during 2005, 2004 and 2003, respectively, in connection with its limited and general partnership interests in us.

The ownership interests in us and Enterprise Products GP that are owned or controlled by EPCO and its affiliates, other than Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of an EPCO affiliate. EPCO s credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, us and TEPPCO. In the event of a default under such credit facility, a change in control of us or our general partner could occur.

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. During 2005, we paid this affiliate $17.6 million for such services. In addition, we buy from and sell certain NGL products to another affiliate of EPCO at market-related prices in the normal course of business. During 2005, our revenues from this affiliate were $0.3 million and our purchases from this affiliate were $61 million.

We also lease office space in various buildings from affiliates of EPCO related to our corporate headquarters in Houston, Texas. During 2005, our operating lease expense recorded in connection with these agreements was $3.3 million. The rental rates in these agreements approximate market rates.

Relationship with TEPPCO. In February 2005, an affiliate of EPCO acquired 100% of the membership interests of TEPPCO GP and 2,500,000 common units of TEPPCO for approximately $1.2 billion in cash. TEPPCO GP owns a 2% general partner interest in TEPPCO and is the managing partner of TEPPCO and its subsidiaries. In June 2005, the employees of TEPPCO became EPCO employees. We paid $17.2 million to TEPPCO during 2005 for NGL pipeline transportation and storage services. In addition, certain directors of Enterprise Products GP and Enterprise GP Holdings (Messrs. Bachmann, Creel and Fowler) were elected as additional directors of TEPPCO GP in February 2006.

In March 2005, the Bureau of Competition of the FTC delivered written notice to EPCO s legal advisor that it was conducting a non-public investigation to determine whether EPCO s acquisition of TEPPCO GP may tend substantially to lessen competition. No filings were required under the Hart-Scott-Rodino Act in connection with EPCO s purchase of TEPPCO GP. EPCO and its affiliates, including us, may receive similar inquiries from other regulatory authorities and we intend to cooperate fully with any such investigations and inquiries. In response to such FTC investigation or any inquiries EPCO and its affiliates may receive from other regulatory authorities, we may be required to divest certain assets.

In February 2006, we and TEPPCO entered into a letter of intent related to the formation of a joint venture to expand TEPPCO s Jonah Gas Gathering System (the Jonah system) located in the Green River Basin in southwestern Wyoming. The proposed expansion of the Jonah system would increase the natural gas gathering and transportation capacity of the Jonah system from 1.5 Bcf/d to 2.0 Bcf/d. The letter of intent stipulates that we will be responsible for all activities related to the construction of the expansion of the Jonah system, including advancing of all expenditures necessary to plan, engineer and construct the expansion project. We estimate that total funds needed for this project will approximate $200 million and that the expansion assets will be placed in service in late 2006. The amounts we advance to complete the expansion of the Jonah system will constitute a subscription for an equity interest in the proposed joint venture. TEPPCO has the option to return to us up to 100% of the amounts we advance (i.e., the subscription amounts). If TEPPCO returns any portion of the subscription to us, the relative interests of us and TEPPCO in the new joint venture would be adjusted accordingly. The proposed joint venture arrangement will terminate without liability to either party if TEPPCO returns 100% of the advances we make in connection with the expansion project, including carrying costs and expenses.

In January 2006, we announced our intent to purchase from TEPPCO the Pioneer natural gas processing plant located in Opal, Wyoming and the rights to process natural gas originating from the Jonah and Pinedale fields in the Greater Green River Basin in Wyoming. Upon execution of definitive agreements, the receipt of all necessary regulatory approval and approvals from the boards of directors of TEPPCO and our general partner, we would purchase the Pioneer plant for $36 million and commence construction to increase its processing capacity from 275 MMcf/d to 550 MMcf/d. We expect this expansion to be completed in mid-2006.

Employee Partnership. In connection with the initial public offering of Enterprise GP Holdings, EPCO formed the Employee Partnership. EPCO serves as the general partner of the Employee Partnership. In connection with the closing of Enterprise GP Holdings initial public offering, EPCO Holdings, Inc., a wholly owned subsidiary of EPCO, borrowed $51 million under its credit facility and contributed the borrowings to its wholly-owned subsidiary, Duncan Family Interests, Inc. (Duncan Family Interests), which, in turn, contributed $51 million to the Employee Partnership as a capital contribution with respect to its Class A limited partner interest. The Employee Partnership used the contributed funds to purchase 1,821,428 units directly from Enterprise GP Holdings at the initial public offering price. Certain EPCO employees, including all of Enterprise Products GP s executive officers other than the Chairman, have been issued Class B limited partner interests without any capital contribution and admitted as Class B limited partners of the Employee Partnership.

Unless otherwise agreed to by EPCO, Duncan Family Interests and a majority in interest of the Class B limited partners of the employee partnership, the employee partnership will terminate at the earlier of five years following the closing of Enterprise GP Holdings initial public offering or a change in control of Enterprise GP Holdings or its general partner. The Employee Partnership has the following material terms with respect to distributions:

§ *Distributions of Cashflow* each quarter, 100% of the distributions from units held by the Employee Partnership will be distributed to Duncan Family Interests until it has received the Class A preferred return (as defined below), and any remaining distributions from the Employee Partnership will be distributed to the Class B limited partners. The Class A preferred return will equal 1.5625% per quarter, or 6.25% per annum, of Duncan Family Interest s capital base. Duncan Family Interest s capital base will equal $51 million, increased by any unpaid Class A preferred return from prior periods, and decreased by any distributions of sale proceeds to Duncan Family Interests as described below.

§ *Liquidating Distributions* Upon liquidation of the Employee Partnership, units having a fair market value equal to Duncan Family Interest s capital base will be distributed to Duncan Family Interests, plus any accrued Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partners.

§ *Sale Proceeds* If the Employee Partnership sells any units, the sale proceeds will be distributed to Duncan Family Interests and the Class B limited partners in the same manner as liquidating distributions described above.

The Class B limited partner interests in the Employee Partnership that are owned by EPCO employees are subject to forfeiture if the participating employee s employment with EPCO and its affiliates is terminated prior to the fifth anniversary of the closing of Enterprise GP Holdings initial public offering, with customary exceptions for death, disability and certain retirements. The risk of forfeiture associated with the Class B limited partner interests in the Employee Partnership will also lapse upon certain change of control events.

Enterprise Products Partners and Enterprise Products GP will not reimburse EPCO, the Employee Partnership or any of their affiliates or partners, through the administrative services agreement or otherwise, for any expenses related to the Employee Partnership or the contribution of $51 million to the Employee Partnership or the purchase of the units by the Employee Partnership.

For the period that the Employee Partnership was in existence during 2005, EPCO accounted for this share-based compensation arrangement using APB 25. Under APB 25, the value of the Class B limited partner interests was accounted for in a manner similar to stock appreciation rights. EPCO s non-cash compensation expense related to this arrangement is allocated to us and other affiliates of EPCO based on our usage of each employee s services. During 2005, we recorded $2 million of non-cash compensation expense associated with the Employee Partnership. For additional information regarding our equity awards, see Note 5.

Administrative Services Agreement. We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (ASA). We and our general partner, Enterprise GP Holdings and its general partner, and TEPPCO and its general partner are parties to the ASA. The significant terms of the ASA are as follows:

§ EPCO will provide selling, general, administrative, management, engineering and operating services as may be necessary to manage and operate our business, properties and assets (in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.

§ We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including 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 has allowed us to participate as named insureds in its overall insurance program with the associated costs being charged 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 partners equity accounted for as a general contribution to our partnership. At December 31, 2005, the retained leases were for a cogeneration unit and approximately 100 railcars. Should we decide to exercise the purchase options associated with the retained leases, $2.3 million would be payable in 2008 and $3.1 million in 2016.

Our operating costs and expenses for 2005, 2004 and 2003 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets.

Likewise, our general and administrative costs for 2005 and 2004 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).

During 2003, our reimbursement to EPCO for administrative services was facilitated by the payment of a fixed-fee for costs associated with employees and functions present at our initial public offering in 1998 and on an actual basis for costs associated with employees hired in connection with our expansion activities up to that time. To the extent that the fixed-fee portion of this reimbursement method was less than EPCO s actual charges for such employees, we recorded a non-cash related party expense for the difference.

The ASA addresses potential conflicts that may arise among Enterprise Products Partners, Enterprise Products GP, Enterprise GP Holdings, EPE Holdings and the EPCO Group, which includes EPCO and its affiliates (excluding Enterprise Products GP, Enterprise Products Partners and its subsidiaries, Enterprise GP Holdings and EPE Holdings and TEPPCO, TEPPCO GP and their controlled affiliates). The ASA provides, among other things, that:

§ if a business opportunity to acquire equity securities is presented to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or Enterprise GP Holdings, then Enterprise GP Holdings will have the first right to pursue such opportunity. Equity securities are defined to include:

  § general partner interests (or securities which have characteristics similar to general partner interests) and incentive distribution rights or similar rights in publicly traded partnerships 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

  § incentive distribution rights and limited partner interests (or securities which have characteristics similar to incentive distribution rights 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 desire to acquire the equity securities until such time as EPE Holdings advises the EPCO Group and Enterprise Products GP that Enterprise GP Holdings has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to exceed $100 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 Audit and Conflicts Committee of EPE Holdings. If the purchase price is reasonably likely to be less than such threshold amount, the Chief Executive Officer of EPE Holdings may make the determination to decline the acquisition without consulting the Audit and Conflicts Committee of EPE Holdings. In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group and Enterprise Products GP, Enterprise Products Partners will have the second right to the pursue such acquisition. Enterprise Products Partners will be presumed to desire to acquire the equity securities until such time as Enterprise Products GP advises the EPCO Group 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 Enterprise Products GP s Chief Executive Officer and Audit and Conflicts Committee. In the event that Enterprise Products Partners abandons the acquisition and so notifies the EPCO Group, the EPCO Group may pursue the acquisition without any further obligation to any other party or offer such opportunity to other affiliates.

§ if any business opportunity not covered by the preceding bullet point is presented to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or Enterprise GP Holdings, Enterprise Products Partners will have the first right to pursue such opportunity. Enterprise Products Partners will be presumed to desire to pursue the business opportunity until such time as Enterprise Products GP advises the EPCO Group and EPE Holdings that Enterprise Products Partners has abandoned the pursuit of such business opportunity. In the event that the purchase price or cost associated with the business opportunity is reasonably likely to exceed $100 million, the decision to decline the business opportunity will be made by the Chief Executive Officer of Enterprise Products GP after consultation with and subject to the approval of the Audit and Conflicts Committee of Enterprise Products GP. If the purchase price or cost is reasonably likely to be less than such threshold amount, the Chief Executive Officer of Enterprise Products GP may make the determination to decline the business opportunity without consulting Enterprise Products GP s Audit and Conflicts Committee. In the event that Enterprise Products Partners abandons the business opportunity and so notifies the EPCO Group and EPE Holdings, Enterprise GP Holdings will have the second right to the pursue such business opportunity. Enterprise GP Holdings will be presumed to desire to pursue such business opportunity until such time as EPE Holdings advises the EPCO Group that Enterprise GP Holdings has abandoned the pursuit of such business opportunity. In determining whether or not to pursue the business opportunity, Enterprise GP Holdings will follow the same procedures applicable to Enterprise Products Partners, as described above but utilizing EPE Holdings Chief Executive Officer and Audit and Conflicts Committee. In the event that Enterprise GP Holdings abandons the business opportunity and so notifies the EPCO Group, the EPCO Group may pursue the business opportunity without any further obligation to any other party or offer such opportunity to other affiliates.

None of the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or Enterprise GP Holdings have any obligation to present business opportunities to TEPPCO, TEPPCO GP or their controlled affiliates, and TEPPCO, TEPPCO GP and their controlled affiliates have no obligation to present business opportunities to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or Enterprise GP Holdings.

The ASA also outlines an overall corporate governance structure and provides policies and procedures to address potential conflicts of interest among the parties to the ASA, including protection of the confidential information of each party from the other parties and the sharing of EPCO employees between the parties. Specifically, the ASA provides, among other things, that:

§ there shall be no overlap in the independent directors of Enterprise Products GP, EPE Holdings and TEPPCO GP;

§ there shall be no sharing of EPCO employees performing commercial and development activities involving certain defined potential overlapping assets between us, Enterprise GP Holdings, and EPCO and its other affiliates (excluding TEPPCO and subsidiaries) on one hand and TEPPCO and its subsidiaries and TEPPCO GP on the other hand; and

§ certain screening procedures are to be followed if an EPCO employee performing commercial and development activities becomes privy to commercial information relating to a potential overlapping asset of any entity for which such employee does not perform commercial and development activities.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. See Note 17 for a discussion of this alignment of commercial interests. 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 $318.8 million, $233.9 million and $212.7 million for 2005, 2004 and 2003. In addition, we have furnished $1.2 million in letters of credit on behalf of Evangeline at December 31, 2005.

§ We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Expenses with Promix were $26 million, $23.2 million and $17.5 million for 2005, 2004 and 2003. Additionally, revenues from Promix were $25.8 million, $18.6 million and $19.6 million for 2005, 2004 and 2003.

§ We perform management services for certain of our unconsolidated affiliates. These fees were $8.3 million, $2.1 million and $1.5 million for 2005, 2004 and 2003.

Relationship with Shell

In 2004 and 2003, our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from Shell. We also lease from Shell its 45.4% interest in one of our propylene fractionation facilities located in Mont Belvieu, Texas.

In connection with our March 2005 universal registration statement, we registered for resale 35,368,522 common units owned by Shell and 5,631,478 common units owned by a third party, Kayne Anderson MLP Investment Company, which had been acquired from Shell. We were obligated to register the resale of these common units under a registration rights agreement we executed with Shell in connection with our September 1999 acquisition of certain assets of Shell s Gulf Coast midstream energy business.

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19. Provision for Income Taxes for Certain Pipeline Operations

Our provision for income taxes relates to federal income tax and state franchise and income tax obligations of Seminole and Dixie, which are both corporations and represent our only consolidated subsidiaries subject to such income taxes. Our federal and state income tax provision is summarized below:

	For Year Ended December 31,		
	2005	2004	2003
Current:			
Federal	$ 1,105		
State	301	$ 157	$ 47
Total current	1,406	157	47
Deferred:			
Federal	5,968	1,620	4,556
State	988	1,984	690
Total deferred	6,956	3,604	5,246
Total provision for income taxes	$ 8,362	$ 3,761	$ 5,293

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 of these subsidiaries is as follows:

	For Year Ended December 31,		
	2005	2004	2003
Taxes computed by applying the federal statutory rate	$ 7,656	$ 2,308	$ 4,811
State income taxes (net of federal benefit)	838	1,392	479
Tax benefit charged to cumulative effect of change in accounting principle	65		
Other permanent differences	(197)	61	3
Provision for income taxes	$ 8,362	$ 3,761	$ 5,293
Effective income tax rate	38%	57%	39%

The deferred tax asset shown on our consolidated balance sheet reflects the net tax effects of temporary differences between the subsidiary s carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The significant components of our deferred tax asset are as follows:

	At December 31,	
	2005	2004
Deferred Tax Assets:		
Property, plant and equipment Dixie	$ 855	
Net operating loss carryforwards	14,251	$ 11,735
Employee benefit plans	2,403	

Deferred revenue	448	520
Accruals	116	
Total Deferred Tax Assets	18,073	12,255
Deferred Tax Liabilities:		
Property, plant and equipment Seminole	13,907	5,269
Other	6	
Total Deferred Tax Liabilities	13,913	5,269
Net Deferred Tax Assets	$ 4,160	$ 6,986
Current portion of deferred tax assets	$ 554	$ 519
Long-term portion of deferred tax assets	$ 3,606	$ 6,467

20. Earnings per Unit

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing units (excluding restricted units) outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of time-vested and performance-based restricted common 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).

The distribution-bearing Class B special units were included in the calculation of basic earnings per unit prior to their conversion to common units in 2004. The non-distribution bearing Class A special units were included in the calculation of diluted earnings per unit prior to their conversion to common units in 2003.

Treasury units were not considered to be outstanding units; therefore, they were excluded from the computation of both basic and diluted earnings per unit.

In a period of net operating losses, the restricted 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 in accordance with 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 allocated to limited partner interests is net of our general partner s share of such earnings. The following table shows the allocation of net income to our general partner for the periods indicated:

	For The Year Ended December 31, 2005	2004	2003
Net income	$ 419,508	$ 268,261	$ 104,546
Less incentive earnings allocations to Enterprise Products GP	(63,884)	(32,391)	(19,699)
Net income available after incentive earnings allocation	355,624	235,870	84,847
Multiplied by Enterprise Products GP ownership interest (1)	2.0%	2.0%	1.2%
Standard earnings allocation to Enterprise Products GP	$ 7,112	$ 4,717	$ 1,030
Incentive earnings allocation to Enterprise Products GP	$ 63,884	$ 32,391	$ 19,699
Standard earnings allocation to Enterprise Products GP	7,112	4,717	1,030
Enterprise Products GP interest in net income	$ 70,996	$ 37,108	$ 20,729

(1) Enterprise Products GP s ownership interest in us increased from 1% to 2% in December 2003 as a result of restructuring its overall ownership interest in us and our Operating Partnership. The 1.2% ownership interest shown for 2003 reflects the weighted-average of the Enterprise Products GP s ownership interest during the year.

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The following table presents our calculation of basic and diluted earnings per unit for the periods shown:

	For The Year Ended December 31, 2005	2004	2003
Income before changes in accounting principles and Enterprise Products GP interest	$ 423,716	$ 257,480	$ 104,546
Cumulative effect of changes in accounting principles	(4,208)	10,781	
Net income	419,508	268,261	104,546
Enterprise Products GP interest in net income	(70,996)	(37,108)	(20,729)
Net income available to limited partners	$ 348,512	$ 231,153	$ 83,817
BASIC EARNINGS PER UNIT			
Numerator			
Income before changes in accounting principles and Enterprise Products GP interest	$ 423,716	$ 257,480	$ 104,546
Cumulative effect of changes in accounting principles	(4,208)	10,781	
Enterprise Products GP interest in net income	(70,996)	(37,108)	(20,729)
Limited partners interest in net income	$ 348,512	$ 231,153	$ 83,817
Denominator			
Common units	381,857	262,838	183,779
Subordinated units			15,955
Class B special units		2,532	181
Total	381,857	265,370	199,915
Basic earnings per unit			
Income before changes in accounting principles and Enterprise Products GP interest	$ 1.11	$ 0.97	$ 0.52
Cumulative effect of changes in accounting principles	(0.01)	0.04	
Enterprise Products GP interest in net income	(0.19)	(0.14)	(0.10)
Limited partners interest in net income	$ 0.91	$ 0.87	$ 0.42
DILUTED EARNINGS PER UNIT			
Numerator			
Income before changes in accounting principles and Enterprise Products GP interest	$ 423,716	$ 257,480	$ 104,546
Cumulative effect of changes in accounting principles	(4,208)	10,781	
Enterprise Products GP interest in net income	(70,996)	(37,108)	(20,729)
Limited partners interest in net income	$ 348,512	$ 231,153	$ 83,817
Denominator			
Common units	381,857	262,838	183,779

Subordinated units			15,955
Class A special units			5,808
Class B special units		2,532	181
Time-vested restricted units	606	141	
Performance-based restricted units	45	14	
Series F2 convertible units		22	
Incremental option units	455	498	644
Total	382,963	266,045	206,367
Diluted earnings per unit			
Income before changes in accounting principles and Enterprise Products GP interest	$ 1.11	$ 0.97	$ 0.51
Cumulative effect of changes in accounting principles	(0.01)	0.04	
Enterprise Products GP interest in net income	(0.19)	(0.14)	(0.10)
Limited partners interest in net income	$ 0.91	$ 0.87	$ 0.41

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21. Commitments and Contingencies

Litigation

On occasion, we are named as a defendant in litigation relating to our normal business operations, 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 activity. We are not aware of any significant litigation, pending or threatened, that may have a significant adverse effect on our financial position or results of operations.

A number of lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing MTBE, although generally such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary that owns the facility. It is possible, however, that MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits. In connection with our purchase of additional equity interests in the owner of the octane-additive production facility in 2003 from an affiliate of Devon Energy Corporation (Devon) and in 2004 from an affiliate of Sunoco, Inc. (Sun), Devon and Sun indemnified us for any liability (including liabilities described above) that are in respect of periods prior to the date we purchased such interests. There are no dollar limits or deductibles associated with the indemnities we received from Sun and Devon with respect to potential claims linked to the period of time they held ownership interests in the facility.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2005. A description of each type of contractual obligation follows.

		Payment or Settlement due by Period					
Contractual Obligations	**Total**	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**
Scheduled maturities of long-term debt	$ 4,866,068		$ 517,000		$ 500,000	$ 1,049,068	$ 2,800,000
Operating lease obligations	$ 179,623	$ 19,099	$ 18,638	$ 15,210	$ 10,352	$ 9,737	$ 106,587
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 1,518,016	$ 216,690	$ 216,690	$ 217,283	$ 216,690	$ 216,690	$ 433,973
NGLs	$ 6,095,907	$ 684,250	$ 619,048	$ 499,900	$ 499,900	$ 499,900	$ 3,292,909
Petrochemicals	$ 1,290,952	$ 1,079,110	$ 159,511	$ 52,331			
Other	$ 87,162	$ 31,578	$ 23,176	$ 21,548	$ 10,712	$ 148	
Underlying major volume commitments:							
Natural gas (in BBtus)	127,850	18,250	18,250	18,300	18,250	18,250	36,550
NGLs (in MBbls)	63,130	9,251	7,741	5,086	5,086	5,086	30,880
Petrochemicals (in MBbls)	19,717	16,525	2,381	811			
Service payment commitments	$ 5,765	$ 5,037	$ 689	$ 39			
Capital expenditure commitments	$ 208,575	$ 208,575					

Scheduled Maturities of Long-Term Debt. We have long and short-term payment obligations under debt agreements such as the indentures governing our Operating Partnership s senior notes and the credit agreement governing our Operating Partnership s Multi-Year Revolving Credit Facility. Amounts shown in the table represent our scheduled future maturities of long-term 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 for the periods indicated.

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, and (iii) land held pursuant to right-of-way agreements. In general, our material lease agreements have original terms that range from 14 to 20 years and include renewal options that could extend the agreements for up to an additional 20 years. Our rental payments under these agreements are generally fixed rates, as specified in the individual contract, which may be subject to escalation provisions for inflation and other market-determined factors. With regards to our underground storage leases, we may also be assessed contingent rental payments when our storage volumes exceed our reserved capacity.

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. In general, we are 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 2005, 2004 or 2003.

The operating lease commitments shown in the preceding table exclude the non-cash related party expense associated with equipment leases contributed to us by EPCO at our formation (the retained leases). EPCO remains liable for the actual cash lease payments associated with these agreements, which it accounts for as operating leases. At December 31, 2005, the retained leases were for a cogeneration unit and approximately 100 railcars. EPCO s minimum future rental payments under these leases are $2.1 million for each of the years 2006 through 2008, $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 partners 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. During 2004, we exercised our option to purchase an isomerization unit and related equipment for $17.8 million. Should we decide to exercise the remaining purchase options, up to an additional $2.3 million would be payable in 2008 and $3.1 million in 2016.

Lease and rental expense included in operating income was $34.9 million, $19.5 million and $17.8 million during 2005, 2004 and 2003, 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 NGLs, petrochemicals and natural gas 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, 2005 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. At December 31, 2005, we do not have any product purchase commitments with fixed or minimum pricing provisions having remaining terms in excess of one year.

We have long and short-term commitments to pay third-party providers for services such as maintenance agreements. Our contractual payment obligations vary by contract. The preceding table shows our future payment obligations under these service contracts.

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Lastly, we have short-term payment obligations relating to capital projects we have initiated and are also responsible for our share of such obligations associated with the capital projects of our unconsolidated affiliates. These commitments represent unconditional payment obligations that we or our unconsolidated affiliates have agreed to pay vendors for services rendered or products purchased. Our capital expenditure commitments also include $95 million for the acquisition of certain pipeline assets during 2006. The preceding table shows these combined amounts for the periods indicated.

Redelivery Commitments

We transport and store NGL, petrochemical and natural gas volumes for third parties under various processing, storage, transportation and similar agreements. Under the terms of these agreements, we are generally required to redeliver volumes to the owner on demand. We are insured for any physical loss of such volumes due to catastrophic events. At December 31, 2005, NGL and petrochemical volumes aggregating 15.2 million barrels were due to be redelivered to their owners along with 15,512 BBtus of natural gas.

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 18). This includes the costs associated with equity-based awards granted to these employees. At December 31, 2005, there were 2,082,000 options outstanding to purchase common units under the 1998 Plan that had been granted to employees for which we were responsible for reimbursing EPCO for the costs of such awards.

The weighted-average strike price of the unit option awards granted was $22.16 per common unit. At December 31, 2005, 727,000 of these unit options were exercisable. An additional 25,000, 840,000 and 490,000 of these unit options will be exercisable in 2006, 2008 and 2009, respectively. 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.

Performance Guaranty

In December 2004, a subsidiary of the Operating Partnership entered into the Independence Hub Agreement (the Agreement) with six oil and natural gas producers. The Agreement, as amended, obligates the subsidiary (i) to construct an offshore platform production facility to process 1 Bcf/d of natural gas and condensate and (ii) to process certain natural gas and condensate production of the six producers following construction of the platform facility.

In conjunction with the Agreement, our Operating Partnership guaranteed the performance of its subsidiary under the Agreement up to $426 million. In December 2004, 20% of this guaranteed amount was assumed by Cal Dive, our joint venture partner in the Independence Hub project. The remaining $341 million represents our share of the anticipated cost of the platform facility. This amount represents the cap on our Operating Partnership s potential obligation to the six producers for the cost of constructing the platform in the remote scenario where the six producers take over the construction of the platform facility. This performance guarantee continues until the earlier to occur of (i) all of the guaranteed obligations of the subsidiary shall have been terminated, paid or otherwise discharged in full, (ii) upon mutual written consent of our Operating Partnership and the producers or (iii) mechanical completion of the production facility. We expect that mechanical completion of the platform will occur in November 2006; therefore, we anticipate that the performance guaranty will exist until at least this future date.

In accordance with FIN 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*, we recorded the fair value of the performance guaranty using an expected present value approach. Given the remote probability that our Operating Partnership would be required to perform under the guaranty, we have estimated the fair value of the performance guaranty at approximately $1.2 million, which is a component of other current liabilities on our Consolidated Balance Sheet at December 31, 2005.

22. Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

We operate predominantly in the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs and crude oil. As such, our results of operations, cash flows and financial condition may be affected by (i) changes in the commodity prices of these hydrocarbon products and (ii) changes in the relative price levels among these hydrocarbon products. In general, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations 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 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 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.

A reduction in demand for NGL 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 with NGL products, (iii) increased competition from petroleum-based products due to the pricing differences, (iv) adverse weather conditions, (v) government regulations affecting commodity prices and production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could also adversely affect our results of operations, cash flows and financial position.

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.

Counterparty Risk with respect to Financial Instruments

Where we are exposed to credit risk in our financial 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 and we do not anticipate nonperformance by our counterparties.

Weather-Related Risks

We participate as named insureds in EPCO s current insurance program, which provides us with property damage, business interruption and other coverages, which are customary for the nature and scope of our operations. Historically, most of the insurance carriers in EPCO s portfolio of coverage were rated A or higher by recognized ratings agencies. The financial impact of recent storm events such as Hurricanes Katrina and Rita has resulted in the lowering of credit ratings of many insurance carriers, with a number of providers also being placed on negative credit watch. We are unaware of any of our existing carriers dropping below the A rating level. At present, there is no indication of any insurance carrier in the EPCO insurance program being unable or unwilling to meet its coverage obligations.

We believe that EPCO maintains adequate insurance coverage on behalf of us, although insurance will not cover every type of interruption that might occur. As a result of insurance market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available for only reduced amounts 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. At present, the annualized cost of insurance premiums allocated to us by EPCO for all lines of coverage is approximately $21.1 million. This amount includes a $3.7 million increase in premiums related to Hurricanes Katrina and Rita that we recognized during 2005.

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 and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. 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 partners and, accordingly, adversely affect the market price of our common units.

The following is a discussion of the general status of insurance claims related to recent significant storm events that affected our assets. 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 in the near term as additional information becomes available to us.

Hurricane Ivan insurance claims. Our final purchase price allocation for the GulfTerra Merger includes a $26.2 million receivable for insurance claims related to expenditures to repair property damage to certain GulfTerra assets caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004 prior to the GulfTerra Merger. These expenditures represent our total costs to restore the former GulfTerra damaged facilities to operation. Since this loss event occurred prior to completion of the GulfTerra Merger, the claim was filed under the insurance program of GulfTerra and El Paso. Since year end 2005, we received cash reimbursements from insurance carriers totaling $24.1 million related to these property damage claims, and we expect to recover the remaining $2.1 million by mid-2006. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

In addition, we have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan. During the fourth quarter of 2005, we received $4.8 million from such claims. In addition, we estimate an additional $15 million to $16 million will be received during the first quarter of 2006. To the extent we receive cash proceeds from such business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income 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. Inspection and evaluation of property damage to our facilities is a continuing effort. We expensed $5 million during 2005 related to property damage insurance deductibles for these storms. To the extent that insurance proceeds from property damage claims do not cover our expenditures (in excess of the insurance deductibles we have expensed), such shortfall will be expensed when realized. We recorded $15.5 million of estimated recoveries from property damage claims based on amounts expended through December 31, 2005. In addition, we expect to file business interruption claims for losses related to these hurricanes. To the extent we receive cash proceeds from such business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period of receipt.

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23. Supplemental Cash Flow Information

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 Year Ended December 31,		
	2005	2004	2003
Decrease (increase) in:			
Accounts and notes receivable	$ (363,857)	$ (453,904)	$ (54,388)
Inventories	(148,846)	(44,202)	49,932
Prepaid and other current assets	(51,163)	2,726	11,073
Other assets	58,762	(6,073)	(226)
Increase (decrease) in:			
Accounts payable	45,802	110,497	(6,720)
Accrued gas payable	349,979	286,089	128,050
Accrued expenses	(161,989)	8,800	(16,677)
Accrued interest	858	(199)	15,012
Other current liabilities	2,274	6,534	(4,196)
Other liabilities	1,785	(3,993)	(972)
Net effect of changes in operating accounts	$ (266,395)	$ (93,725)	$ 120,888
Cash payments for interest, net of $22,046, $2,766 and $1,595 capitalized in 2005, 2004 and 2003, respectively	$ 239,088	$ 135,797	$ 112,712
Cash payments for federal and state income taxes	$ 5,160	$ 182	$ 453

Supplemental cash flow information regarding our investing activities related to business combinations and asset purchases in 2005, 2004 and 2003 are as follows:

	For Year Ended December 31,		
	2005	2004	2003
Fair value of assets acquired	$ 353,176	$ 5,946,294	$ 127,185
Less liabilities assumed	(23,940)	(2,269,893)	(70,037)
Net assets acquired	329,236	3,676,401	57,148
Less equity issued		(2,910,772)	
Less cash acquired	(2,634)	(40,968)	(19,800)
Cash used for business combinations, net of cash received	$ 326,602	$ 724,661	$ 37,348

We incurred liabilities for construction in progress and property additions that had not been paid at December 31, 2005, 2004 and 2003 of $130.2 million, $62.4 million and $9.1 million, respectively. Such amounts are not included under the caption Capital expenditures on the Statements of Consolidated Cash Flows.

On certain of our capital projects, third parties may be 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. We received $47 million, $8.9 million and $0.9 million as contributions in aid of our construction costs during 2005, 2004 and 2003, respectively.

Net income for 2005 includes a gain on the sale of assets of $5.5 million resulting from the sale of our 50% ownership interest in Starfish. We were required to sell our investment in Starfish in connection with gaining regulatory approval for the GulfTerra Merger.

Net income for 2004 includes a gain on sale of assets of $15.1 million resulting from the satisfaction of certain requirements of an asset sale agreement whereby we sold a 50% ownership interest in Cameron Highway to a third party. Of the $15.1 million gain we recognized, $5 million was realized in December 2004 and the remainder represents a receivable due from the third party in 2006.

In June 2005, we received $47.5 million in cash from Cameron Highway as a return of investment. These funds were distributed to us in connection with the refinancing of Cameron Highway s project debt (see Note 14).

24. Selected Quarterly Data (Unaudited)

The following table presents selected quarterly financial data for 2005 and 2004:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2005: (1)				
Revenues	$ 2,555,522	$ 2,671,768	$ 3,249,291	$ 3,780,378
Operating income	165,464	125,506	194,397	177,649
Income before changes in accounting principles	109,256	70,659	131,169	112,632
Net income	109,256	70,659	131,169	108,424
Income per unit before changes in accounting principles:				
Basic	$ 0.25	$ 0.14	$ 0.29	$ 0.24
Diluted	$ 0.25	$ 0.14	$ 0.29	$ 0.24
Net income per unit:				
Basic	$ 0.25	$ 0.14	$ 0.29	$ 0.23
Diluted	$ 0.25	$ 0.14	$ 0.29	$ 0.23
For the Year Ended December 31, 2004: (1)				
Revenues	$ 1,704,890	$ 1,713,346	$ 2,040,271	$ 2,862,695
Operating income	88,783	66,010	92,917	175,284
Income before changes in accounting principles	51,747	33,148	57,231	115,354
Net income	62,528	33,148	57,231	115,354
Income per unit before changes in accounting principles:				
Basic	$ 0.21	$ 0.11	$ 0.20	$ 0.28
Diluted	$ 0.21	$ 0.11	$ 0.20	$ 0.28
Net income per unit:				
Basic	$ 0.26	$ 0.11	$ 0.20	$ 0.28
Diluted	$ 0.26	$ 0.11	$ 0.20	$ 0.28

(1) Our results of operations have increased since the completion of the GulfTerra Merger on September 30, 2004.

25. Condensed Financial Information of Operating Partnership

The Operating Partnership conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of our Operating Partnership.

We act as guarantor of all our Operating Partnership s consolidated debt obligations, with the exception of the Seminole Notes, the Dixie revolving credit facility and the amounts remaining outstanding under GulfTerra s senior subordinated notes. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. Our guarantee of these debt obligations is both full and unconditional and non-recourse to Enterprise Products GP. For additional information regarding our consolidated debt obligations, see Note 14.

The reconciling items between our consolidated financial statements and those of our Operating Partnership are insignificant.

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The following table shows condensed consolidated balance sheet data for the Operating Partnership at the dates indicated:

	December 31, 2005	December 31, 2004
ASSETS		
Current assets	$ 1,960,015	$ 1,425,574
Property, plant and equipment, net	8,689,024	7,831,467
Investments in and advances to unconsolidated affiliates	471,921	519,164
Intangible assets, net	913,626	980,601
Goodwill	494,033	459,198
Deferred tax asset	3,606	6,467
Other assets	39,014	58,139
Total	$ 12,571,239	$ 11,280,610
LIABILITIES AND PARTNERS EQUITY		
Current liabilities	$ 1,894,227	$ 1,582,911
Long-term debt	4,833,781	4,266,236
Other long-term liabilities	84,486	63,521
Minority interest	106,159	73,858
Partners equity	5,652,586	5,294,084
Total	$ 12,571,239	$ 11,280,610
Total Operating Partnership debt obligations guaranteed by us	$ 4,844,000	$ 4,267,229

The following table shows condensed consolidated statements of operations data for the Operating Partnership for the periods indicated:

	For Year Ended December 31, 2005	2004	2003
Revenues	$ 12,256,959	$ 8,321,202	$ 5,346,431
Costs and expenses	11,605,923	7,946,816	5,083,701
Equity in income (loss) of unconsolidated affiliates	14,548	52,787	(13,960)
Operating income	665,584	427,173	248,770
Other income (expense)	(226,075)	(153,251)	(133,798)
Income before provision for income taxes, minority interest and changes in accounting principles	439,509	273,922	114,972
Provision for income taxes	(8,362)	(3,761)	(5,293)
Income before minority interest and changes in accounting principles	431,147	270,161	109,679
Minority interest	(5,989)	(8,072)	(3,095)

Income before changes in accounting principles	425,158	262,089	106,584
Cumulative effect of changes in accounting principles	(4,208)	10,781	
Net income	$ 420,950	$ 272,870	$ 106,584

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SCHEDULE II

ENTERPRISE PRODUCTS PARTNERS L.P.
VALUATION AND QUALIFYING ACCOUNTS

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts	Deductions	Balance At End of Period
Accounts receivable trade					
Allowance for doubtful accounts (1)					
2005	$ 24,310	$ 2,238	$ 1,141	$ (1,840)	$ 25,849
2004	20,423	4,840	4,158	(5,111)	24,310
2003	21,196	1,239	71	(2,083)	20,423
Inventories					
Allowance for uncollectible imbalances (2)					
2005	8,463	3,153	4,400	(4,536)	11,480
2004			8,463		8,463
Other current liabilities					
Reserve for environmental liabilities (3)					
2005	115	95	65		275
2004	9		115	(9)	115
2003	9				9
Reserve for inventory gains and losses (4)					
2005	750	4,761	8,314	(3,825)	10,000
2004	2,700	900		(2,850)	750
2003	1,271	3,000		(1,571)	2,700
Reserve for BEF turnaround accrual (5)					
2004	2,013			(2,013)	
2003			2,124	(111)	2,013
Other long-term liabilities					
Reserve for environmental liabilities (3)					
2005	22,004	44	(65)	(168)	21,815
2004	1,133		21,136	(265)	22,004
2003	135		1,061	(63)	1,133
Reserve for BEF turnaround accrual (5)					
2004	5,001			(5,001)	
2003			5,001		5,001

(1) Additions charged to costs and expenses primarily represent periodic accruals for uncollectible accounts based on specific identification and estimates of future uncollectible accounts. Additions charged to other accounts

primarily represent net realizable values recorded in connection with business combinations. Deductions primarily represent uncollectible accounts receivable charged to the reserve. See Note 2 for additional information regarding our allowance for doubtful accounts.

(2) Additions charged to costs and expenses primarily represent periodic accruals for uncollectible natural gas imbalance receivable based on specific identification of problem accounts. Additions charged to other accounts primarily represent uncollectible natural gas imbalance receivables charged to the reserve. See Note 2 for additional information regarding our natural gas imbalances.

(3) Additions charged to costs and expenses primarily represent periodic accruals for environmental remediation costs. Additions charged to other accounts primarily represent present values recorded in connection with business combinations. Deductions primarily represent environmental remediation costs charged to the reserve. See Note 2 for additional information regarding our environmental costs.

(4) This reserve exists to cover anticipated net losses attributable to the storage of NGL and petrochemical products in underground storage caverns. Additions charged to costs and expense primarily represent periodic accruals for net well losses. Additions charged to other accounts primarily represent product gains. Deductions primarily represent product losses. Management regularly reviews the status of the reserve and determines the appropriate level based on historical and anticipated storage well activity. The reserve increased during 2005 generally due to expected storage well activity and the acquisition of storage assets during the period.

(5) We eliminated this reserve in connection with changing the accounting principle used by a subsidiary related to its planned major maintenance activities. See Note 8 for additional information regarding this change in accounting principle.

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

None.

Item 9A. ***Controls and Procedures.***

Disclosure controls and procedures

Our management, including the chief executive officer (CEO) and chief financial officer (CFO) of Enterprise Products GP, evaluated the effectiveness of our disclosure controls and procedures, including internal controls over financial reporting, as of December 31, 2005. This evaluation concluded that our disclosure controls and procedures, including internal controls over financial reporting, are effective to ensure that material information relating to Enterprise Products Partners is made known to management on a timely basis. Our management noted no material weaknesses in the design or operation of our internal controls over financial reporting that are likely to adversely affect our ability to record, process, summarize and report financial information. In addition, no fraud involving management or employees who have a significant role in our internal controls over financial reporting was detected.

Our disclosure controls and procedures are designed to provide us with a reasonable assurance that the information required to be disclosed in reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. The disclosure controls and procedures are also designed to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO of our general partner, as appropriate to allow such persons to make timely decisions regarding required disclosures.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within Enterprise Products Partners have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurance of achieving our desired control objectives, and our CEO and CFO have concluded that our disclosure controls and procedures are effective in achieving that level of reasonable assurance as of December 31, 2005.

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Internal control over financial reporting

Our internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements in accordance with GAAP. These internal controls over financial reporting were designed under the supervision of our management, including the CEO and CFO of Enterprise Products GP, and include policies and procedures that:

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

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

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

In accordance with Item 308 of SEC Regulation S-K, management is required to provide an annual report regarding internal controls over our financial reporting. This report, which includes management s assessment of the effectiveness of our internal controls over financial reporting, is found on page 154.

Changes in internal control over financial reporting during the fourth quarter of 2005. There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934), or in other factors during the fourth quarter of 2005, that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Other internal control updates for 2005. In accordance with SEC guidance, we opted to exclude the operations we acquired in connection with the GulfTerra Merger from the scope of our fiscal 2004 Section 404 Annual Report on Internal Controls Over Financial Reporting (the Section 404 Annual Report). In September 2005, we completed the integration of these operations and related computer and other data systems into our existing control environment. In February 2005, we purchased an additional 26% ownership interest in Dixie. As a result, Dixie became a majority-owned consolidated subsidiary of ours; thus, our 2005 Statement of Consolidated Operations and Comprehensive Income includes ten months of consolidated results from Dixie. Prior to its consolidation, we accounted for our investment in Dixie using the equity method. Dixie was included in our evaluations of our disclosure controls and procedures, including internal controls over financial reporting, as of December 31, 2005. Our Section 404 Annual Report for 2005 includes the operations we acquired in connection with the GulfTerra Merger and Dixie transactions.

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MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2005

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, including the Chief Executive Officer and the Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to Enterprise Products Partners management and board of directors regarding the preparation and fair presentation of published financial statements. However, our management does not represent that our disclosure controls and procedures or internal controls over financial reporting will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only a reasonable, not an absolute, assurance that the objectives of the control system are met.

Our management assessed the effectiveness of Enterprise Products Partners internal control over financial reporting as of December 31, 2005. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework.* This assessment included design effectiveness and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2005, Enterprise Products Partners internal control over financial reporting is effective based on those criteria.

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein under Item 9A of this annual report.

Our Audit and Conflicts Committee is composed of directors who are not officers or employees of Enterprise Products GP. It meets regularly with members of management, the internal auditors and the representatives of the independent registered public accounting firm to discuss the adequacy of Enterprise Products Partners internal controls over financial reporting, financial statements and the nature, extent and results of the audit effort. Management reviews with the Audit and Conflicts Committee all of Enterprise Products Partners significant accounting policies and assumptions affecting the results of operations. Both the independent registered public accounting firm and internal auditors have direct access to the Audit and Conflicts Committee without the presence of management.

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this Annual Report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on February 27, 2006.

/s/ Robert G. Phillips		*/s/ Michael A. Creel*	
Name:	Robert G. Phillips	Name:	Michael A. Creel
Title:	Chief Executive Officer of our general partner, Enterprise Products GP, LLC	Title:	Chief Financial Officer of our general partner, Enterprise Products GP, LLC

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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 management s assessment, included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting, that Enterprise Products Partners L.P. and its consolidated subsidiaries (Enterprise Products Partners) maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Enterprise Products Partners management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of Enterprise Products Partners internal control over financial reporting based on our audit.

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

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

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

In our opinion, management s assessment that Enterprise Products Partners maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, Enterprise Products Partners maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM (Continued)

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet, the related statements of consolidated operation and comprehensive income, consolidated cash flows, consolidated partners equity and the consolidated financial statement schedule as of and for the year ended December 31, 2005 of Enterprise Products Partners and our report dated February 27, 2006 expressed an unqualified opinion on those financial statements and the financial statement schedule.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 27, 2006

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

None.

PART III

Item 10. ***Directors and Executive Officers of the Registrant.***

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for the management or operations of our business. These functions are performed by the employees of EPCO pursuant to an administrative services agreement under the direction of the Board of Directors and executive officers of Enterprise Products GP, our general partner. For a description of the administrative services agreement, please read *Certain Relationships and Related Transactions Relationship with EPCO* under Item 13 of this annual report.

Directors and Executive Officers of Enterprise Products GP

The following table sets forth the name, age and position of each of the directors and executive officers of Enterprise Products GP at February 27, 2006. Each executive officer holds the same respective office shown below in the general partner of the Operating Partnership. Each member of the Board of Directors serves until such member s death, resignation or removal. The executive officers are elected for one-year terms and may be removed, with or without cause, only by the Board of Directors. Our unitholders do not elect the officers or directors of Enterprise Products GP. Dan. L. Duncan, through his indirect control of Enterprise Products GP, has the ability to elect, remove and replace at any time, all of the officers and directors of Enterprise Products GP.

Notwithstanding any contractual limitation on its obligations or duties, Enterprise Products GP is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to Enterprise Products GP. Whenever possible, Enterprise Products GP intends to make any such indebtedness or other obligations non-recourse to itself.

Name	Age	Position with Enterprise Products GP
Dan L. Duncan (1)	73	Director and Chairman
Robert G. Phillips (1)	51	Director, President and Chief Executive Officer
Dr. Ralph S. Cunningham (1)	65	Director, Group Executive Vice President and Chief Operating Officer
Michael A. Creel (1)	52	Director, Executive Vice President and Chief Financial Officer
Richard H. Bachmann (1)	53	Director, Executive Vice President, Chief Legal Officer and Secretary
W. Randall Fowler (1)	49	Director, Senior Vice President and Treasurer
E. William Barnett (2,3,5)	73	Director
Philip C. Jackson (2,3,4)	77	Director
Stephen L. Baum (2,3)	65	Director
James H. Lytal (1)	48	Executive Vice President
A.J. Teague (1)	60	Executive Vice President
Michael J. Knesek (1)	51	Senior Vice President, Controller and Principal Accounting Officer

(1) Executive officer

(2) Member of Audit and Conflicts Committee

(3) Member of Governance Committee

(4) Chairman of Audit and Conflicts Committee

(5) Chairman of Governance Committee

Because we are a limited partnership and meet the definition of a controlled company under the listing standards of the NYSE, we are not required to comply with certain requirements of the NYSE. Accordingly, we have elected to not comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of Directors of Enterprise Products GP be comprised of a majority of independent directors. In addition, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of Directors of Enterprise Products GP maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Dan L. Duncan was elected Chairman and a Director of Enterprise Products GP in April 1998 and Chairman and a Director of the general partner of our Operating Partnership in December 2003. Mr. Duncan has served as Chairman and a Director of EPE Holdings since April 2005 and as Chairman of EPCO since 1979.

Robert G. Phillips was elected President and Chief Executive Officer of Enterprise Products GP in February 2005. Mr. Phillips served as President and Chief Operating Officer of Enterprise Products GP from September 2004 to February 2005. Mr. Phillips has served as a Director of Enterprise Products GP since September 2004; a Director of the general partner of our Operating Partnership since September 2004; and a Director of EPE Holdings since February 2006. Mr. Phillips served as a Director of GulfTerra s general partner from August 1998 until September 2004. He served as Chief Executive Officer for GulfTerra and its general partner from November 1999 until September 2004 and as Chairman from October 2002 until September 2004. He served as Executive Vice President of GulfTerra from August 1998 to October 1999. Mr. Phillips served as President of El Paso Field Services Company from June 1997 to September 2004. He served as President of El Paso Energy Resources Company from December 1996 to July 1997, President of El Paso Field Services Company from April 1996 to

December 1996 and Senior Vice President of El Paso Corporation from September 1995 to April 1996. For more than five years prior, Mr. Phillips was Chief Executive Officer of Eastex Energy, Inc.

Dr. Ralph S. Cunningham was elected Group Executive Vice President and Chief Operating Officer of Enterprise Products GP in December 2005 and a Director in February 2006. Dr. Cunningham previously served as a Director of Enterprise Products GP from 1998 until March 2005 and served as

Chairman and a Director of the general partner of TEPPCO (otherwise referred to as TEPPCO GP) from March 2005 until November 2005. He retired in 1997 from CITGO Petroleum Corporation, where he had served as President and Chief Executive Officer since 1995. He serves as a Director of Tetra Technologies, Inc. (a publicly traded energy services and chemical company), EnCana Corporation (a Canadian publicly traded independent oil and natural gas company) and Agrium, Inc. (a Canadian publicly traded agricultural chemicals company) and was a Director of EPCO from 1987 to 1997.

Michael A. Creel was elected Executive Vice President of Enterprise Products GP and EPCO in January 2001, after serving as a Senior Vice President of Enterprise Products GP and EPCO from November 1999 to January 2001. Mr. Creel, a certified public accountant, served as Chief Financial Officer of EPCO from June 2000 through April 2005 and was named Chief Operating Officer of EPCO in April 2005. In June 2000, Mr. Creel was also named Chief Financial Officer of Enterprise Products GP. Mr. Creel has served as a Director of the general partner of our Operating Partnership since December 2003, and has served as President, Chief Executive Officer and a Director of EPE Holdings since August 2005. Mr. Creel was elected a Director of Edge Petroleum Corporation (a publicly traded oil and natural gas exploration and production company) in October 2005 and a Director of Enterprise Products GP and TEPPCO GP in February 2006.

Richard H. Bachmann was elected Executive Vice President, Chief Legal Officer and Secretary of Enterprise Products GP and EPCO in January 1999 and a Director of Enterprise Products GP in February 2006. Mr. Bachmann previously served as a Director of Enterprise Products GP from June 2000 to January 2004. Mr. Bachmann has served as a Director of the general partner of our Operating Partnership since December 2003 and has served as Executive Vice President, Chief Legal Officer and Secretary of EPE Holdings since August 2005. Mr. Bachmann was elected a Director of EPE Holdings and TEPPCO GP in February 2006 and of EPCO in January 1999.

W. Randall Fowler was elected Senior Vice President and Treasurer of Enterprise Products GP in February 2005 and a Director in February 2006. Mr. Fowler, a certified public accountant (inactive), joined us as Director of Investor Relations in January 1999 and served as Treasurer and a Vice President of Enterprise Products GP and EPCO from August 2000 to February 2005. Mr. Fowler has served as Senior Vice President and Chief Financial Officer of EPE Holdings since August 2005 and as Chief Financial Officer of EPCO since April 2005. Mr. Fowler was elected a Director of EPE Holdings and TEPPCO GP in February 2006.

E. William Barnett was elected a Director of Enterprise Products GP in March 2005. Mr. Barnett practiced law with Baker Botts L.L.P. from 1958 until his retirement in 2004. In 1984, he became Managing Partner of Baker Botts L.L.P. and continued in that role for fourteen years until 1998. He was Senior Counsel to the firm from 1998 until June 2004, when he retired from the firm. Mr. Barnett served as Chairman of the Board of Trustees of Rice University from 1996 to July 2005. He is a Life Trustee of The University of Texas Law School Foundation; a Director of St. Luke s Episcopal Health System; a Director of the Center for Houston s Future and a current Director and former Chairman of the Houston Zoo, Inc. (the operating arm of the Houston Zoo). He is a Director of Reliant Energy, Inc., a publicly traded electric services company. He is also Director and former Chairman of the Greater Houston Partnership and Chairman of the Advisory Board of the Baker Institute for Public Policy at Rice University. He also served as a trustee of Baylor College of Medicine from 1993 until 2004. Mr. Barnett is a member of Enterprise Products GP s Audit and Conflicts Committee and serves as Chairman of its Governance Committee.

Philip C. Jackson was elected a Director of Enterprise Products GP in August 2005. Mr. Jackson was an Adjunct Professor of Finance at Birmingham-Southern College from 1989 until his retirement in 1999. Mr. Jackson served as Vice Chairman of Compass Bancshares, Inc. from 1980 until 1989 and as a consultant and outside Director from 1978 until 1980. He was a member of the Board of Governors of the Federal Reserve System from 1975 until 1978. Mr. Jackson is a member of the Advisory Board of Compass Bank; a Trustee of Birmingham-Southern College; a Director of Saul Centers, Inc., a publicly traded real estate investment trust; and a Governor of the Mortgage Bankers Association of America. Mr. Jackson is a member of Enterprise Products GP s Governance Committee and serves as Chairman of its Audit and Conflicts Committee.

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Stephen L. Baum was elected a Director of Enterprise Products GP in February 2006. Mr. Baum served as Chairman, Chief Executive Officer and a Director of Sempra Energy from September 2000 until his retirement in January 2006. He served as Vice Chairman and Chief Operating Officer of Sempra Energy from June 1998 to June 2000. Mr. Baum was President and Chief Executive Officer of Enova Corp., the parent company of San Diego Gas & Electric (SDG&E) from 1996 to 1997, and was an Executive Vice President of SDG&E from 1993 to 1996. Prior to joining SDG&E in 1985, he was Senior Vice President and General Counsel of the New York Power Authority from 1982 to 1985. Mr. Baum has served as a Director of Computer Sciences Corp. (a publicly traded information technology company) since 1999 and serves as Chairman of its Audit Committee. Mr. Baum serves on the Audit and Conflicts Committee and the Governance Committee of Enterprise Products GP.

James H. Lytal was elected Executive Vice President of Enterprise Products GP in September 2004. Mr. Lytal served as a Director of GulfTerra s general partner from August 1994 until September 2004, and as President of GulfTerra and its general partner from July 1995 until September 2004. He served as Senior Vice President of GulfTerra and its general partner from August 1994 to June 1995. Prior to joining GulfTerra, Mr. Lytal served in various capacities with the oil and gas exploration and production and natural gas pipeline businesses of United Gas Pipeline Company, Texas Oil and Gas, Inc. and American Pipeline Company

A.J. Teague was elected an Executive Vice President of Enterprise Products GP in November 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC.

Michael J. Knesek, a certified public accountant, was elected Senior Vice President and Principal Accounting Officer of Enterprise Products GP in February 2005. Previously, Mr. Knesek served as Principal Accounting Officer and a Vice President of Enterprise Products GP from August 2000 to February 2005. Mr. Knesek has served as Senior Vice President and Principal Accounting Officer of EPE Holdings since August 2005. Mr. Knesek has been the Controller and a Vice President of EPCO since 1990.

Governance Matters

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals, and maintain the trust and confidence of investors, employees, suppliers, business partners and stakeholders. The following is a brief description of certain existing practices we use to maintain strong governance principles.

Independence of Board Members. A key element for strong governance is independent members of the board of directors. Pursuant to the NYSE listing standards, a director will be considered independent if the board determines that he or she does not have a material relationship with Enterprise Products GP or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with Enterprise Products GP or us). Based on the foregoing, the Board has affirmatively determined that E. William Barnett, Philip C. Jackson and Stephen L. Baum are independent directors under the NYSE rules.

Heightened Independence for Audit and Conflicts Committee Members. As required by the Sarbanes-Oxley Act of 2002, the SEC adopted rules that direct national securities exchanges and associations to prohibit the listing of securities of a public company if members of its audit committee do not satisfy a heightened independence standard. In order to meet this standard, a member of an audit committee may not receive any consulting fee, advisory fee or other compensation from the public company other than fees for service as a director or committee member and may not be considered an affiliate of the public company. Neither Enterprise Products GP nor any individual member of its Audit and Conflicts Committee has relied on any exemption in the NYSE rules to establish such individual s independence. Based on the foregoing criteria, the Board of Directors of Enterprise Products GP has affirmatively determined that all members of its Audit and Conflicts Committee satisfy this heightened independence requirement.

Audit Committee Financial Expert. An audit committee plays an important role in promoting effective corporate governance, and it is imperative that members of an audit committee have requisite financial literacy and expertise. As required by the Sarbanes-Oxley Act of 2002, SEC rules require that a public company disclose whether or not its audit committee has an audit committee financial expert as a member. An audit committee financial expert is defined as a person who, based on his or her experience, satisfies all of the following attributes:

§ An understanding of generally accepted accounting principles and financial statements.

§ An ability to assess the general application of such principles in connection with the accounting for estimates, accruals, and reserves.

§ Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and level of complexity of issues that can reasonably be expected to be raised by our financial statements, or experience actively supervising one or more persons engaged in such activities.

§ An understanding of internal controls and procedures for financial reporting.

§ An understanding of audit committee functions.

Based on the information presented, the Board of Directors has affirmatively determined that Philip C. Jackson satisfies the definition of audit committee financial expert.

Executive Sessions of Board. The Board of Directors of Enterprise Products GP holds regular executive sessions in which non-management board members meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the Presiding Director, who is responsible for leading and facilitating such executive sessions. Currently, the Presiding Director is Philip C. Jackson, the Chairman of the Audit and Conflicts Committee.

In accordance with the rules of the NYSE, we have designated our toll-free, confidential Hotline as the method for interested parties to communicate with the Presiding Director, alone, or with the non-management Directors of Enterprise Products GP as a group. All calls to this Hotline are reported to the Chairman of the Audit and Conflicts Committee of Enterprise Products GP, who is responsible for communicating any necessary information to the other non-management directors as a group. The number of our confidential Hotline is (877) 888-0002. The Hotline is operated by The Network, an independent contractor that specializes in providing feedback/reporting services to more than 1,000 companies in a variety of industries.

Committees of Board of Directors. The Board of Directors of Enterprise Products GP has two committees, the Audit and Conflicts Committee and the Governance Committee, which are described in the following sections:

Audit and Conflicts Committee

In accordance with NYSE rules and Section 3(a)(58)(A) of the Securities Exchange Act of 1934, the Board of Directors of Enterprise Products GP has named three of its members to serve on its Audit and Conflicts Committee. The members of the Audit and Conflicts Committee are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment.

The members of the Audit and Conflicts Committee must have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements, and at least one member of the committee shall have accounting or related financial management expertise. The members of the Audit and Conflicts Committee are Steve L. Baum, E. William Barnett and Philip C. Jackson, Chairman. The primary responsibilities of the Audit and Conflicts Committee include:

§ monitoring the integrity of our financial reporting process and related systems of internal control;

§ ensuring our legal and regulatory compliance and that of Enterprise Products GP;

§ overseeing the independence and performance of our independent public accountants;

§ approving all services performed by our independent public accountants;

§ providing for an avenue of communication among the independent public accountants, management, internal audit function and the Board of Directors;

§ encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels;

§ reviewing areas of potential significant financial risk to our businesses; and

§ approving awards granted under our 1998 Long-Term Incentive Plan.

The Audit and Conflicts Committee also has the authority to review specific matters as to which the Board of Directors believes there may be a conflict of interests in order to determine if the resolution of such conflict proposed by Enterprise Products GP is fair and reasonable to us. Any matters approved by the Audit and Conflicts Committee are conclusively deemed to be fair and reasonable to our business, approved by all of our partners and not a breach by Enterprise Products GP or its Board of Directors of any duties they may owe us or our unitholders.

Pursuant to its formal written charter adopted in June 2000 and amended in August 2003, the Audit and Conflicts Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The Audit and Conflicts Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Governance Committee

The Governance Committee of Enterprise Products GP s Board of Directors is comprised of the three independent directors: E. William Barnett, Chairman, Philip C. Jackson and Stephen L. Baum. The Governance Committee is appointed by the Board to assist the Board in fulfilling its oversight responsibilities. The Governance Committee s primary duties and responsibilities are to develop and recommend to the Board a set of governance principles applicable to us, review the qualifications of candidates for Board membership, screen and interview possible candidates for Board membership and communicate with members of the Board regarding Board meeting format and procedures.

Governance Guidelines. Governance guidelines, together with committee charters, provide the framework for effective governance. The Board of Directors of Enterprise Products GP has adopted the Governance Guidelines of Enterprise Products Partners, which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibility of committees, the conduct and frequency of board and committee meetings, management succession, director access to management and outside advisors, director compensation, director orientation and continuing education, and annual self-evaluation of the board. The Board of Directors of Enterprise Products GP recognizes that effective governance is an on-going process, and thus, the Board will review the Governance Guidelines of Enterprise Products Partners annually or more often as deemed necessary or appropriate.

Code of Conduct. Enterprise Products GP has adopted a Code of Conduct that applies to all directors, officers and employees. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance, the reporting of compliance issues and discipline for violations of the code.

Code of Ethics. Enterprise Products GP has adopted a code of ethics, the Code of Ethical Conduct for Senior Financial Officers and Managers, that applies to our CEO, CFO, Principal Accounting Officer and senior financial and other managers. In addition to other matters, this code of ethics establishes policies to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications and prompt internal reporting violations of the code.

Web Access. We provide access through our website at www.epplp.com to current information relating to governance, including the Audit and Conflicts Committee Charter, the Governance Committee Charter, the Code of Ethical Conduct for Senior Financial Officers and Managers, the Governance Guidelines of Enterprise Products Partners and other matters impacting our governance principles. You may also contact our investor relations department at (713) 880-6521 for printed copies of these documents free of charge.

Indemnification of Directors and Officers. Under our limited partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events any person who is or was an employee (other than an officer) or agent of our partnership.

Section 16(a) Beneficial Ownership Reporting Compliance

Under the federal securities laws, Enterprise Products GP, directors of Enterprise Products GP, executives (and certain other) officers, and any persons holding more than 10% of our common units are required to report their ownership of common units and any changes in that ownership to us and the SEC. Specific due dates for these reports have been established by regulation, and we are required to disclose in this report any failure to file by these dates during 2005. Richard S. Snell and Lynn L. Bourdon, III each filed a late report during 2005 covering one transaction completed in 2005. In addition, we filed a late report during 2005 on behalf of Philip C. Jackson covering one transaction completed in 2005.

Item 11. ***Executive Compensation.***

We are managed by our general partner, Enterprise Products GP, the executive officers of which are employees of EPCO. Our reimbursement for the compensation of executive officers is governed by the administrative services agreement with EPCO (see Item 13 of this annual report).

Summary Compensation Table

The following table presents cash compensation paid or awarded by us in 2005 with respect to our current and former Chief Executive Officers and our four other most highly compensated executive officers at December 31, 2005 (collectively, the named executive officers).

Name and Principal Position	Year	Annual Compensation: Salary	Annual Compensation: Bonus	Long-term Compensation Awards: Restricted Unit Awards ($)[1]	Long-term Compensation Awards: Securities Underlying Options (#)	All Other Compensation[2]
Robert G. Phillips, [3,4]	2005	$675,000	$200,000	$ 529,400	70,000	$ 14,700
Chief Executive Officer	2004	150,000		991,910	500,000	10,500
O.S. Andras, [5]	2005	402,600				11,550
Former Chief Executive	2004	798,000				14,350
Officer	2003	877,800				14,000
A. J. Teague, [6]	2005	412,000	90,000	264,700	35,000	14,700
Executive Vice President	2004	392,500	50,000	251,400	35,000	14,350
	2003	381,280	80,000			14,000
James H. Lytal, [3,7]	2005	338,750	100,000	264,700	35,000	4,200
Executive Vice President	2004	80,000		873,311	35,000	1,600
Charles E. Crain, [8]	2005	293,550	75,000	158,820	25,000	14,700
Senior Vice President	2004	267,000	50,000	621,667	25,000	14,350
	2003	250,500	50,000			14,000
Gil H. Radtke, [9]	2005	287,150	75,000	158,820	25,000	14,700
Senior Vice President	2004	258,333	80,000	125,700	25,000	14,350
	2003	243,333	50,000			14,000

(1) The dollar value of time-vested restricted common unit awards is calculated by multiplying the number of units awarded by the closing price of our unrestricted common units on the date of each grant. Time-vested restricted unit awards entitle recipients to acquire the underlying common units (at no cost to them) once the defined vesting period expires, subject to certain forfeiture provisions. The restrictions on time-vested restricted common units lapse four years from the date of grant. During the vesting period, each holder of time-vested restricted units is entitled to receive cash distributions per unit in an amount equal to those received by our common unitholders.

(2) These amounts primarily represent contributions made by EPCO to the 401(k) plan of the named executive officers.

(3) Mr. Phillips and Mr. Lytal became executive officers of our general partner in September 2004 upon completion of the GulfTerra Merger. Mr. Phillips became our Chief Executive Officer in February 2005.

(4) At December 31, 2005, Mr. Phillips held 62,553 time-vested restricted units valued at $1,501,898 based on a closing price of $24.01 per unit for our unrestricted common units on that date.

(5) Mr. Andras resigned his position as our Chief Executive Officer in February 2005; however, he remained as a non-executive officer until his retirement in June 2005.

(6) At December 31, 2005, Mr. Teague held 22,000 time-vested restricted units valued at $528,220 based on a closing price of $24.01 per unit for our unrestricted common units on that date.

(7) At December 31, 2005, Mr. Lytal held 47,532 time-vested restricted units valued at $1,141,243 based on a closing price of $24.01 per unit for our unrestricted common units on that date.

(8) At December 31, 2005, Mr. Crain held 33,277 time-vested restricted units valued at $798,981 based on a closing price of $24.01 per unit for our unrestricted common units on that date.

(9) At December 31, 2005, Mr. Radtke held 12,000 time-vested restricted units valued at $288,120 based on a closing price of $24.01 per unit for our unrestricted common units on that date.

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Common Unit Option Grants to Named Executive Officers during 2005

The following table provides information concerning the award of options to purchase our common units to the named executive officers during 2005. These awards were made under EPCO s 1998 Long-Term Incentive Plan (the 1998 Plan).

Name	Number of Securities Underlying Options Granted (#)	Individual Grants Percent of Total Options Granted to EPCO Employees in 2005	Exercise Price ($/Unit)	Expiration Date	Potential Realizable Value at Assumed Annual Rates of Unit Price Appreciation for Option Term (1) 5% ($)	10% ($)
Robert G. Phillips	70,000	13.2%	$ 26.47	Aug. 2009	$ 399,000	$ 859,600
A.J. Teague	35,000	6.6%	$ 26.47	Aug. 2009	199,500	429,800
James H. Lytal	35,000	6.6%	$ 26.47	Aug. 2009	199,500	429,800
Charles E. Crain	25,000	4.7%	$ 26.47	Aug. 2009	142,000	307,000
Gil H. Radtke	25,000	4.7%	$ 26.47	Aug. 2009	142,000	307,000

(1) These amounts represent the result of calculations at the 5% and 10% assumed compounded appreciation rates from the date of grant to the end of the option term (i.e., the expiration date) as required by the SEC by Item 402(c)(2)(vi)(A) of Regulation S-K and are not intended to forecast the future trading prices of our common units.

Common Unit Options Exercised by Named Executive Officers and Fiscal Year-End Values

The following table provides information concerning (i) the exercise of options to purchase our common units by named executive officers during 2005 and (ii) the value of unexercised common unit options held by such individuals at December 31, 2005.

Name	Units Acquired on Exercise (#)	Value Realized ($)(1)	Number of Securities Underlying Unexercised Options at December 31, 2005 Exercisable	Unexercisable	Value of Unexercised In-the-Money Options at December 31, 2005 (2) Exercisable	Unexercisable
Robert G. Phillips				570,000		$ 415,000
A.J. Teague	100,000	$ 1,000,750		70,000		140,350
James H. Lytal				70,000		29,050
Charles E. Crain				50,000		100,250

Gil H. Radtke	100,000	50,000	100,250

(1) The value realized represents the difference between the exercise price of the common unit options and the market (sale) price of the common units on the date of exercise without considering any taxes that may have been owed by the beneficiary.

(2) Value is based on the $24.01 closing price of our common units on December 31, 2005.

Equity Awards Under EPE Unit L.P.

All of the named executive officers are Class B limited partners of EPE Unit L.P. (the Employee Partnership). For information regarding the Employee Partnership, please read *Relationship with EPCO and affiliates* included under Item 13 of this annual report.

At December 31, 2005, the named executive officers approximate percentage interests in the total profits interest of the Employee Partnership were as follows: Robert G. Phillips, 6.9%, A. J. Teague, 4.6%, James H. Lytal, 4.6%, Charles E. Crain, 2.3% and Gil H. Radtke, 2.3%. If the Employee Partnership had been liquidated at December 31, 2005, the estimated value of the total profits interest would have been approximately $16.8 million, of which each named executive officer would have received his proportionate share.

Compensation of Directors of Enterprise Products GP

Neither we nor Enterprise Products GP provide any additional compensation to employees of EPCO who serve as directors of our general partner. The employees of EPCO who served as directors of Enterprise Products GP during 2005 were Messrs. Duncan, Andras and Phillips. The employees of EPCO currently serving as directors are Messrs. Duncan, Phillips, Cunningham, Creel, Bachmann and Fowler.

At February 27, 2006, our independent directors are Messrs. Jackson, Barnett and Baum. Enterprise Products GP is responsible for compensating these directors for their services. Its standard compensation arrangement is as follows:

§ Each independent director receives $25,000 in cash and $25,000 worth of restricted common units annually.

§ If the individual serves as chairman of a committee of the Board of Directors, then he receives an additional $7,500 in cash annually.

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

Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information as of February 15, 2006, regarding the beneficial ownership of our common units by:

§ each person known by Enterprise Products GP to beneficially own more than 5% of our common units;

§ each of the named executive officers at December 31, 2005 of Enterprise Products GP;

§ all of the current directors of Enterprise Products GP; and

§ all of the current directors and executive officers of Enterprise Products GP as a group.

The table also presents the ownership of common units of Enterprise GP Holdings L.P. by the directors and executive officers of our general partner. Enterprise GP Holdings owns 100% of the membership interests of Enterprise Products GP.

All information with respect to beneficial ownership has been furnished by the respective directors or officers, as the case may be. Each person has sole voting and dispositive power over the units shown unless otherwise indicated below. The beneficial ownership amounts of certain individuals include options to acquire common units of Enterprise Products Partners that are exercisable within 60 days of the filing date of this annual report (see footnotes).

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	Limited Partner Ownership Interests In			
	Enterprise Products Partners		Enterprise GP Holdings	
Name of Beneficial Owner	**Amount And Nature Of Beneficial Ownership**	**Percent of Class**	**Amount And Nature Of Beneficial Ownership**	**Percent of Class**
Dan L. Duncan:				
Common units owned by EPCO: [1,2]				
DFI Delaware Holdings, L.P.	118,078,425	30.3%		
Duncan Family Interests, Inc.			71,119,631	80.0%
Enterprise GP Holdings L.P.	13,454,498	3.4%		
Common units owned by Dan Duncan LLC [3]			3,726,273	4.2%
Common units owned by Employee Partnership [4]			1,821,428	2.0%
Common units owned by trusts [5]	11,925,670	3.1%	233,271	*
Common units owned directly	695,400	*		
Total for Dan L. Duncan	144,153,993	36.9%	76,900,603	86.5%
Shell U.S. Gas & Power LLC [6]	29,407,549	7.5%		
O.S. Andras [7,8]	3,676,525	*	185,000	*
Robert G. Phillips [8,9]	105,343	*	75,000	*
Dr. Ralph S. Cunningham	2,322	*	4,000	*
Michael A. Creel	102,828	*	35,000	*
Richard H. Bachmann [10]	101,984	*	20,000	*
W. Randall Fowler	48,061	*	3,000	*
E. William Barnett	744	*	10,000	*
Philip C. Jackson	18,725	*		
A. J. Teague [8]	151,976	*	17,000	*
James H. Lytal [8]	64,101	*	5,000	*
Charles E. Crain [8]	132,697	*	20,000	*
Gil H. Radtke [8,11]	128,732	*	10,000	*
All current directors and executive officers of Enterprise Products GP, 12 individuals in total [12]	148,457,992	38.0%	77,254,603	86.9%

** The beneficial ownership of each individual is less than 1% of the registrant s common units outstanding.*

(1) Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to the units beneficially owned by EPCO. The remaining shares of EPCO capital stock are owned primarily by trusts for the benefit of the members of Mr. Duncan s family. The address of EPCO is 2707 North Loop West, Houston, Texas 77008 and the address of Mr. Duncan is 2727 North Loop West, Houston, Texas 77008.

(2)

Essentially all of the ownership interests in Enterprise Products Partners and Enterprise GP Holdings that are owned or controlled by EPCO are pledged as security under an EPCO affiliate s credit facility. EPCO s credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, us and TEPPCO. In the event of a default under such credit facility, a change in control of us or Enterprise GP Holdings could occur. A change in control of Enterprise GP Holdings would result in a change in control of our general partner.

(3) Dan Duncan LLC acquired beneficial ownership of these units in connection with the formation and initial public offering of Enterprise GP Holdings. Dan Duncan LLC is owned by Mr. Duncan.

(4) As a result of control rights EPCO has a result of its general partner interest in the Employee Partnership, Mr. Duncan is deemed beneficial owner of the common units owned by the Employee Partnership.

(5) In addition to the units owned by EPCO, Mr. Duncan is deemed to be the beneficial owner of the common units owned by the Duncan Family 1998 Trust and the Duncan Family 2000 Trust, the beneficiaries of which are the shareholders of EPCO.

(6) We issued these units to Shell US Gas & Power LLC (an affiliate of Shell) in connection with an acquisition of midstream energy assets in 1999. The address of Shell US Gas & Power LLC is 910 Louisiana Street, Houston, Texas 77002. This information is based on Schedule 13(d) filings for Shell made with the SEC through February 15, 2006.

(7) The number of Enterprise Products Partners common units shown for Mr. Andras includes 100,000 common units held by a trust for which he has disclaimed beneficial ownership.

(8) These individuals are the named executive officers of Enterprise Products Partners at December 31, 2005.

(9) The number of Enterprise Products Partners common units shown for Mr. Phillips includes 4,540 common units held by trusts for which he has disclaimed beneficial ownership.

(10) The number of Enterprise GP Holdings units shown for Mr. Bachmann includes 3,000 units held by trusts for which he has disclaimed beneficial ownership.

(11) The number of Enterprise Products Partners common units shown for Mr. Radtke includes 100,000 common units issued under the 1998 Plan that are exercisable within 60 days of the filing date of this report.

(12) Cumulatively, this group s beneficial ownership amount includes 10,000 options to acquire Enterprise Products Partners common units that were issued under the 1998 Plan. These options are exercisable within 60 days of the filing date of this report.

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Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2005 regarding the 1998 Plan, under which our common units are authorized for issuance to EPCO s key employees and to directors of Enterprise Products GP through the exercise of unit options.

Plan Category	Number of our units to be issued upon exercise of outstanding common unit options (a)	Weighted-average exercise price of outstanding common unit options (b)	Number of our units remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by unitholders:			
Unit options issued under 1998 Plan	2,082,000	$ 22.16	670,000
Equity compensation plans not approved by unitholders:			
None.			
Total for equity compensation plans (1)	2,082,000	$ 22.16	670,000

(1) Of the 2,082,000 unit options outstanding at December 31, 2005, 727,000 were immediately exercisable and an additional 25,000, 840,000, and 490,000 were exercisable in 2006, 2008 and 2009, respectively.

The 1998 Plan is effective until either all available common units under the plan have been issued to participants or the earlier termination of the 1998 Plan by EPCO. The 1998 Plan also provides for the issuance of 3,000,000 restricted common units, of which 2,203,764 remain authorized for issuance at December 31, 2005. During 2005, a total of 263,079 restricted common units were issued (net of forfeitures and vesting) to key employees of EPCO and our independent directors.

For additional information regarding the 1998 Plan and related equity awards, please read Notes 2 and 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Item 13. ***Certain Relationships and Related Transactions.***

The following information summarizes our business relationships and related transactions with entities controlled by Dan L. Duncan during 2005. We have also provided information regarding our business relationships and transactions with our unconsolidated affiliates and Shell.

For information regarding our related party transactions in general, please read Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Relationship with EPCO and affiliates

Statement of Transactions with EPCO and affiliates during 2005. The following table presents a detailed statement of amounts we paid to EPCO and affiliates during 2005 by transaction category (dollars in thousands):

Revenues:	
Sales of NGL products	$ 275
Other	36
Total revenues related to EPCO and affiliates	$ 311
Operating costs and expenses:	
Purchase of NGL products, including freight and storage	$ 94,982
Reimbursement of operating employee costs	193,253
Recognition of non-cash retained lease expense	2,112
Office space lease expense	2,036
Other	751
Total operating costs and expenses related to EPCO and affiliates	293,134
General and administrative costs:	
Reimbursement of overhead employee costs	39,051
Office space lease expense	1,218
Other	685
Total general and administrative costs related to EPCO and affiliates	40,954
Total costs and expenses related to EPCO and affiliates	$ 334,088
Cash distributions paid to Enterprise Products GP by us	$ 76,752
Cash distributions paid by us to our common units beneficially owned by EPCO (see Item 12)	$ 243,904
Non-cash expense amount recognized in connection with Employee Partnership equity awards	$ 2,043

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

§ EPCO and its private company subsidiaries;

§ Enterprise Products GP, our sole general partner;

§ Enterprise GP Holdings, which owns and controls our general partner;

§ the Employee Partnership; and

§ TEPPCO and its general partner, which are controlled by affiliates of EPCO.

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

We were formed in 1998 to own and operate certain NGL assets contributed to us by EPCO. EPCO is a private company controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise Products GP. Mr. Duncan owns 50.4% of the voting stock of EPCO. The remaining shares of EPCO capital stock are held primarily by trusts for the benefit of members of Mr. Duncan s family.

At February 15, 2006, EPCO and its affiliates beneficially owned 144,153,993 (or 36.9%) of our outstanding common units. In January 2005, an affiliate of EPCO acquired 13,454,498 of our common units and a 9.9% membership interest in our general partner from El Paso for approximately $425 million in cash. As a result of this transaction and until August 2005, EPCO and certain of its affiliates owned 100% of the membership interests of our general partner and El Paso no longer owned any limited or general partner interest in us.

In August 2005, affiliates of EPCO contributed their 100% membership interests in our general partner and the 13,454,498 of our common units they acquired from El Paso to Enterprise GP Holdings, another affiliate of EPCO. As a result of this contribution, Enterprise GP Holdings owns 100% of the membership interests of our general partner and an approximate 3.4% limited partner interest in us. Enterprise GP Holdings is a publicly traded limited partnership that completed an initial public offering of its common units in August 2005, and its only cash generating assets consist of its general and limited partnership interests in us. At February 15, 2006, EPCO and its affiliates owned 86.5% of Enterprise GP Holdings, including 100% of EPE Holdings.

The principal business activity of Enterprise Products GP is to act as our managing partner. The executive officers and certain of the directors of Enterprise Products GP and Enterprise GP Holdings are employees of EPCO (see Item 10 of this annual report on Form 10-K). Apart from the rights it owns with respect to its general partner interest in us, Enterprise Products GP does not receive any compensation for its services to us as general partner.

We and Enterprise Products GP are both separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from those of EPCO and its other affiliates. EPCO depends on the cash distributions it receives from us, Enterprise GP Holdings and other investments to fund its other operations and to meet its debt obligations. EPCO and its affiliates received $243.9 million in cash distributions from us during 2005 in connection with its limited and general partnership interests in us.

The ownership interests in us and Enterprise Products GP that are owned or controlled by EPCO and its affiliates, other than Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of an EPCO affiliate. EPCO s credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, us and TEPPCO. In the event of a default under such credit facility, a change in control of us or our general partner could occur.

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. During 2005, we paid this affiliate $17.6 million for such services. In addition, we buy from and sell certain NGL products to another affiliate of EPCO at market-related prices in the normal course of business. During 2005, our revenues from this affiliate were $0.3 million and our purchases from this affiliate were $61 million.

We also lease office space in various buildings from affiliates of EPCO related to our corporate headquarters in Houston, Texas. During 2005, our operating lease expense recorded in connection with these agreements was $3.3 million. The rental rates in these agreements approximate market rates.

Relationship with TEPPCO. In February 2005, an affiliate of EPCO acquired 100% of the membership interests of TEPPCO GP and 2,500,000 common units of TEPPCO for approximately $1.2 billion in cash. TEPPCO GP owns a 2% general partner interest in TEPPCO and is the managing partner of TEPPCO and its subsidiaries. In June 2005, the employees of TEPPCO became EPCO employees. We paid $17.2 million to TEPPCO during 2005 for NGL pipeline transportation and storage services. In addition, certain directors of Enterprise Products GP and Enterprise GP Holdings (Messrs. Bachmann, Creel and Fowler) were elected as additional directors of TEPPCO GP in February 2006.

In March 2005, the Bureau of Competition of the FTC delivered written notice to EPCO s legal advisor that it was conducting a non-public investigation to determine whether EPCO s acquisition of TEPPCO GP may tend substantially to lessen competition. No filings were required under the Hart-Scott-

Rodino Act in connection with EPCO s purchase of TEPPCO GP. EPCO and its affiliates, including us, may receive similar inquiries from other regulatory authorities and we intend to cooperate fully with any such investigations and inquiries. In response to such FTC investigation or any inquiries EPCO and its affiliates may receive from other regulatory authorities, we may be required to divest certain assets.

In February 2006, we and TEPPCO entered into a letter of intent related to the formation of a joint venture to expand TEPPCO s Jonah Gas Gathering System (the Jonah system) located in the Green River Basin in southwestern Wyoming. The proposed expansion of the Jonah system would increase the natural gas gathering and transportation capacity of the Jonah system from 1.5 Bcf/d to 2.0 Bcf/d. The letter of intent stipulates that we will be responsible for all activities related to the construction of the expansion of the Jonah system, including advancing of all expenditures necessary to plan, engineer and construct the expansion project. We estimate that total funds needed for this project will approximate $200 million and that the expansion assets will be placed in service in late 2006. The amounts we advance to complete the expansion of the Jonah system will constitute a subscription for an equity interest in the proposed joint venture. TEPPCO has the option to return to us up to 100% of the amounts we advance (i.e., the subscription amounts). If TEPPCO returns any portion of the subscription to us, the relative interests of us and TEPPCO in the new joint venture would be adjusted accordingly. The proposed joint venture arrangement will terminate without liability to either party if TEPPCO returns 100% of the advances we make in connection with the expansion project, including carrying costs and expenses.

In January 2006, we announced our intent to purchase from TEPPCO the Pioneer natural gas processing plant located in Opal, Wyoming and the rights to process natural gas originating from the Jonah and Pinedale fields in the Greater Green River Basin in Wyoming. Upon execution of definitive agreements, the receipt of all necessary regulatory approval and approvals from the boards of directors of TEPPCO and our general partner, we would purchase the Pioneer plant for $36 million and commence construction to increase its processing capacity from 275 MMcf/d to 550 MMcf/d. We expect this expansion to be completed in mid-2006.

Employee Partnership. In connection with the initial public offering of Enterprise GP Holdings, EPCO formed the Employee Partnership to serve as an incentive arrangement for certain employees of EPCO through a profits interest in the Employee Partnership. EPCO serves as the general partner of the Employee Partnership. In connection with the closing of Enterprise GP Holdings initial public offering, EPCO Holdings, Inc., a wholly owned subsidiary of EPCO, borrowed $51 million under its credit facility and contributed the borrowings to its wholly-owned subsidiary, Duncan Family Interests, Inc. (Duncan Family Interests), which, in turn, contributed $51 million to the Employee Partnership as a capital contribution with respect to its Class A limited partner interest. The Employee Partnership used the contributed funds to purchase 1,821,428 units directly from Enterprise GP Holdings at the initial public offering price. Certain EPCO employees, including all of Enterprise Products GP s executive officers other than the Chairman, have been issued Class B limited partner interests without any capital contribution and admitted as Class B limited partners of the Employee Partnership.

Unless otherwise agreed to by EPCO, Duncan Family Interests and a majority in interest of the Class B limited partners of the employee partnership, the employee partnership will terminate at the earlier of five years following the closing of Enterprise GP Holdings initial public offering or a change in control of Enterprise GP Holdings or its general partner. The Employee Partnership has the following material terms with respect to distributions:

§ *Distributions of Cashflow* each quarter, 100% of the distributions from units held by the Employee Partnership will be distributed to Duncan Family Interests until it has received the Class A preferred return (as defined below), and any remaining distributions from the Employee Partnership will be distributed to the Class B limited partners. The Class A preferred return will equal 1.5625% per quarter, or 6.25% per annum, of Duncan Family Interest s capital base. Duncan Family Interest s capital base will equal $51 million, increased by any unpaid Class A preferred return from prior periods, and decreased by any distributions of sale proceeds to Duncan Family Interests as described below.

§ *Liquidating Distributions* Upon liquidation of the Employee Partnership, units having a fair market value equal to Duncan Family Interest s capital base will be distributed to Duncan Family Interests, plus any accrued Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partners.

§ *Sale Proceeds* If the Employee Partnership sells any units, the sale proceeds will be distributed to Duncan Family Interests and the Class B limited partners in the same manner as liquidating distributions described above.

The Class B limited partner interests in the Employee Partnership that are owned by EPCO employees are subject to forfeiture if the participating employee s employment with EPCO and its affiliates is terminated prior to the fifth anniversary of the closing of Enterprise GP Holdings initial public offering, with customary exceptions for death, disability and certain retirements. The risk of forfeiture associated with the Class B limited partner interests in the Employee Partnership will also lapse upon certain change of control events.

Enterprise Products Partners and Enterprise Products GP will not reimburse EPCO, the Employee Partnership or any of their affiliates or partners, through the administrative services agreement or otherwise, for any expenses related to the Employee Partnership or the contribution of $51 million to the Employee Partnership or the purchase of the units by the Employee Partnership.

For the period that the Employee Partnership was in existence during 2005, EPCO accounted for this share-based compensation arrangement using APB 25. Under APB 25, the value of the Class B limited partner interests was accounted for in a manner similar to stock appreciation rights. EPCO s non-cash compensation expense related to this arrangement is allocated to us and other affiliates of EPCO based on our usage of each employee s services. During 2005, we recorded $2 million of non-cash compensation expense associated with the Employee Partnership. For additional information regarding the Employee Partnership, please read Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Administrative Services Agreement. We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (ASA). We and our general partner, Enterprise GP Holdings and its general partner, and TEPPCO and its general partner are parties to the ASA. The significant terms of the ASA are as follows:

§ EPCO will provide selling, general, administrative, management, engineering and operating services as may be necessary to manage and operate our business, properties and assets (in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.

§ We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including 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 has allowed us to participate as named insureds in its overall insurance program with the associated costs being charged 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 partners equity accounted for as a general contribution to our partnership. At December 31, 2005, the retained leases were for a cogeneration unit and approximately 100 railcars. Should we decide to exercise the purchase options associated with the retained leases, $2.3 million would be payable in 2008 and $3.1 million in 2016.

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

Likewise, our general and administrative costs for 2005 include amounts we reimburse to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to 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).

The ASA addresses potential conflicts that may arise among Enterprise Products Partners, Enterprise Products GP, Enterprise GP Holdings, EPE Holdings and the EPCO Group, which includes EPCO and its affiliates (excluding Enterprise Products GP, Enterprise Products Partners and its subsidiaries, Enterprise GP Holdings and EPE Holdings, and TEPPCO, TEPPCO GP and their controlled affiliates). The ASA provides, among other things, that:

§ if a business opportunity to acquire equity securities is presented to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or Enterprise GP Holdings, then Enterprise GP Holdings will have the first right to pursue such opportunity. Equity securities are defined to include:

  § general partner interests (or securities which have characteristics similar to general partner interests) and incentive distribution rights or similar rights in publicly traded partnerships 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

  § incentive distribution rights and limited partner interests (or securities which have characteristics similar to incentive distribution rights 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 desire to acquire the equity securities until such time as EPE Holdings advises the EPCO Group and Enterprise Products GP that Enterprise GP Holdings has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to exceed $100 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 Audit and Conflicts Committee of EPE Holdings. If the purchase price is reasonably likely to be less than such threshold amount, the Chief Executive Officer of EPE Holdings may make the determination to decline the acquisition without consulting the Audit and Conflicts Committee of EPE Holdings. In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group and Enterprise Products GP, Enterprise Products Partners will have the second right to the pursue such acquisition. Enterprise Products Partners will be presumed to desire to acquire the equity securities until such time as Enterprise Products GP advises the EPCO Group 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 Enterprise Products GP s Chief Executive Officer and Audit and Conflicts Committee. In the event that Enterprise Products Partners abandons the acquisition and so notifies the EPCO Group, the EPCO Group may pursue the acquisition without any further obligation to any other party or offer such opportunity to other affiliates.

§ if any business opportunity not covered by the preceding bullet point is presented to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or Enterprise GP Holdings, Enterprise Products Partners will have the first right to pursue such opportunity. Enterprise Products Partners will be presumed to desire to pursue the business opportunity until such time as Enterprise Products GP advises the EPCO Group and EPE Holdings that Enterprise Products Partners has abandoned the pursuit of such business opportunity. In the event that the purchase price or cost associated with the business opportunity is reasonably likely to exceed $100 million, the decision to decline the business opportunity will be made by the Chief Executive Officer of Enterprise Products GP after consultation with and subject to the approval of the Audit and Conflicts Committee of Enterprise Products GP. If the purchase price or cost is reasonably likely to be less than such threshold amount, the Chief Executive Officer of Enterprise Products GP may make the determination to decline the business opportunity without consulting Enterprise Products GP s Audit and Conflicts Committee. In the event that Enterprise Products Partners abandons the business opportunity and so notifies the EPCO Group and EPE Holdings, Enterprise GP Holdings will have the second right to the pursue such business opportunity. Enterprise GP Holdings will be presumed to desire to pursue such business opportunity until such time as EPE Holdings advises the EPCO Group that Enterprise GP Holdings has abandoned the pursuit of such business opportunity. In determining whether or not to pursue the business opportunity, Enterprise GP Holdings will follow the same procedures applicable to Enterprise Products Partners, as described above but utilizing EPE Holdings Chief Executive Officer and Audit and Conflicts Committee. In the event that Enterprise GP Holdings abandons the business opportunity and so notifies the EPCO Group, the EPCO Group may pursue the business opportunity without any further obligation to any other party or offer such opportunity to other affiliates.

None of the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or Enterprise GP Holdings have any obligation to present business opportunities to TEPPCO, TEPPCO GP or their controlled affiliates, and TEPPCO, TEPPCO GP and their controlled affiliates have no obligation to present business opportunities to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or Enterprise GP Holdings.

The ASA also outlines an overall corporate governance structure and provides policies and procedures to address potential conflicts of interest among the parties to the ASA, including protection of the confidential information of each party from the other parties and the sharing of EPCO employees between the parties. Specifically, the ASA provides, among other things, that:

§ there shall be no overlap in the independent directors of Enterprise Products GP, EPE Holdings and TEPPCO GP;

§ there shall be no sharing of EPCO employees performing commercial and development activities involving certain defined potential overlapping assets between us, Enterprise GP Holdings, and EPCO and its other affiliates (excluding TEPPCO and subsidiaries) on one hand and TEPPCO and its subsidiaries and TEPPCO GP on the other hand; and

§ certain screening procedures are to be followed if an EPCO employee performing commercial and development activities becomes privy to commercial information relating to a potential overlapping asset of any entity for which such employee does not perform commercial and development activities.

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Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our consolidated business operations. Since we or EPCO and its other 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 transaction amounts with our unconsolidated affiliates during 2005:

§ We sold $318.8 million of natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. In addition, we have furnished $1.2 million in letters of credit on behalf of Evangeline at December 31, 2005.

§ We paid $26 million to Promix for the transportation, storage and fractionation of NGLs during 2005. In addition, we sold $25.8 million of natural gas to Promix for its plant fuel requirements during 2005.

§ We perform management services for certain of our unconsolidated affiliates. During 2005, these affiliates paid us $8.3 million for such services.

§ We occasionally pay for construction labor costs on behalf of our unconsolidated affiliates during the initial construction phase of their assets. We are fully reimbursed for such amounts. During 2005, we made $0.6 million of such payments on behalf of unconsolidated affiliates.

Relationship with Shell

At February 15, 2006, Shell owned approximately 7.5% of our common units. During 2005, our revenues from Shell totaled $549.1 million and our expenses with Shell were $852 million. Historically, Shell has been one of our largest customers. For the years ended December 31, 2005, 2004 and 2003, Shell accounted for 4.5%, 6.5% and 5.5%, respectively, of our consolidated revenues. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from Shell. We also lease from Shell its 45.4% interest in one of our propylene fractionation facilities located in Mont Belvieu, Texas.

A significant contract affecting our natural gas processing business is the Shell Processing Agreement, which grants us the right to process Shell s (or an assignee s) current and future production within state and federal waters of the Gulf of Mexico. The Shell Processing Agreement includes a life of lease dedication, which may extend the agreement well beyond its initial 20-year term ending in 2019.

In connection with our March 2005 universal registration statement, we registered for resale 35,368,522 common units owned by Shell and 5,631,478 common units owned by a third party, Kayne Anderson MLP Investment Company, which had been acquired from Shell. We were obligated to register the resale of these common units under a registration rights agreement we executed with Shell in connection with our September 1999 acquisition of certain assets of Shell s Gulf Coast midstream energy business.

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

We have engaged Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, Deloitte & Touche) as our principal accountant. The following table summarizes fees we have paid Deloitte & Touche for independent auditing, tax and related services for each of the last two fiscal years (dollars in thousands):

	For Year Ended December 31,	
	2005	**2004**
Audit Fees (1)	$ 4,892	$ 5,227
Audit-Related Fees (2)	14	32
Tax Fees (3)	407	586
All Other Fees (4)	n/a	n/a

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this annual report on Form 10-K.

(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews. This category primarily includes services relating to internal control assessments and accounting-related consulting.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice, and tax planning. This category primarily includes services relating to the preparation of unitholder annual K-1 statements, partnership tax planning and property tax assistance.

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

The Audit and Conflicts Committee of our general partner has approved the use of Deloitte & Touche as our independent principal accountant. In connection with its oversight responsibilities, the Audit and Conflicts Committee has adopted a pre-approval policy regarding any services proposed to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other.

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

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

For Deloitte & Touche to maintain its independence, we are prohibited from using Deloitte & Touche to perform general bookkeeping, management or human resource functions, and any other service

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not permitted by the Public Company Accounting Oversight Board. The Audit and Conflicts Committee s pre-approval policy also precludes Deloitte & Touche from performing any of these services for us.

PART IV

Item 15. *Exhibits and Financial Statement Schedules.*

(a)(1) Financial Statements

Our consolidated financial statements are included under Part II, Item 8 of this annual report. For a listing of these statements and accompanying footnotes, please see *Index to Financial Statements* on page 75 of this annual report.

(a)(2) Financial Statement Schedules

Schedule II Valuation and Qualifying Accounts is included on page 151 of this annual report.

All schedules, except the one listed above, have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

Exhibit Number	Exhibit*
2.1	Purchase and Sale Agreement between Coral Energy, LLC and Enterprise Products Operating L.P. dated September 22, 2000 (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 26, 2000).
2.2	Purchase and Sale Agreement dated January 16, 2002 by and between Diamond-Koch, L.P. and Diamond-Koch III, L.P. and Enterprise Products Texas Operating L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 8, 2002.)
2.3	Purchase and Sale Agreement dated January 31, 2002 by and between D-K Diamond-Koch, L.L.C., Diamond-Koch, L.P. and Diamond-Koch III, L.P. as Sellers and Enterprise Products Operating L.P. as Buyer (incorporated by reference to Exhibit 10.2 to Form 8-K filed February 8, 2002).
2.4	Purchase Agreement by and between E-Birchtree, LLC and Enterprise Products Operating L.P. dated July 31, 2002 (incorporated by reference to Exhibit 2.2 to Form 8-K filed August 12, 2002).
2.5	Purchase Agreement by and between E-Birchtree, LLC and E-Cypress, LLC dated July 31, 2002 (incorporated by reference to Exhibit 2.1 to Form 8-K filed August 12, 2002).
2.6	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.7	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.8	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.9	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso

Exhibit Number	Exhibit*
	EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to the Form 8-K filed April 21, 2004).
2.10	Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C., adopted by GulfTerra GP Holding Company, a Delaware corporation, and Enterprise Products GTM, LLC, a Delaware limited liability company, as of December 15, 2003, (incorporated by reference to Exhibit 2.3 to Form 8-K filed December 15, 2003).
2.11	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C. adopted by Enterprise Products GTM, LLC as of September 30, 2004 (incorporated by reference to Exhibit 2.11 to Registration Statement on Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
2.12	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
3.1	Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 10, 2005).
3.2	Third Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of August 29, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 1, 2005).
3.3	Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. dated as of July 31, 1998 (restated to include all agreements through December 10, 2003)(incorporated by reference to Exhibit 3.1 to Form 8-K filed July 1, 2005).
3.4	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.5	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
4.1	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.2	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.3	Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
4.6	Global Notes representing $450 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.7	

	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.8	Contribution Agreement dated September 17, 1999 (incorporated by reference to Exhibit B to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.9	Registration Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit E to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.10	Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit C to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.11	Amendment No. 1, dated September 12, 2003, to Unitholder Rights Agreement dated September

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Exhibit Number	Exhibit*
	17, 1999 (incorporated by reference to Exhibit 4.1 to Form 8-K filed September 15, 2003).
4.12	Agreement dated as of March 4, 2005 among Enterprise Products Partners L.P., Shell US Gas & Power LLC and Kayne Anderson MLP Investment Company (incorporated by reference to Exhibit 4.31 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.13	$750 Million Multi-Year Revolving Credit Agreement dated as of August 25, 2004, among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents, and Mizuho Corporate Bank, Ltd., SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 4.1 to Form 8-K filed on August 30, 2004).
4.14	Guaranty Agreement dated as of August 25, 2004, by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent for the several lenders that are or become parties to the Credit Agreement included as Exhibit 4.13, above (incorporated by reference to Exhibit 4.2 to Form 8-K filed on August 30, 2004).
4.15	First Amendment dated October 5, 2005, to Multi-Year Revolving Credit Agreement dated as of August 25, 2004, among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, CitiBank, N.A. and JPMorgan Chase Bank, as CO-Syndication Agents, and Mizuho Corporate Bank, Ltd., SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 4.3 to Form 8-K filed on October 7, 2005).
4.16	$2.25 Billion 364-Day Revolving Credit Agreement dated as of August 25, 2004, among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Citicorp North America, Inc. and Lehman Commercial Paper Inc., as Co-Syndication Agents, JPMorgan Chase Bank, UBS Loan Finance LLC and Morgan Stanley Senior Funding, Inc., as Co-Documentation Agents, Wachovia Capital Markets, LLC, Citigroup Global Markets Inc. and Lehman Brothers Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 4.3 to Form 8-K filed on August 30, 2004).
4.17	Guaranty Agreement dated as of August 25, 2004, by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent for the several lenders that are or become parties to the Credit Agreement included as Exhibit 4.16, above (incorporated by reference to Exhibit 4.4 to Form 8-K filed on August 30, 2004).
4.18	Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 6, 2004).
4.19	First Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on October 6, 2004).
4.20	Second Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on October 6, 2004).
4.21	Third Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed on October 6, 2004).
4.22	Fourth Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed on October 6, 2004).
4.23	

	Global Note representing $500 million principal amount of 4.000% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.24	Global Note representing $500 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).

Exhibit Number	Exhibit*
4.25	Global Note representing $150 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.26	Global Note representing $350 million principal amount of 6.650% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.27	Global Note representing $500 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K for the year ended December 31, 2004 filed on March 15, 2005).
4.28	Fifth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on March 3, 2005).
4.29	Sixth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on March 3, 2005).
4.30	Global Note representing $250,000,000 principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed on November 4, 2005).
4.31	Global Note representing $250,000,000 principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed on November 4, 2005).
4.32	Registration Rights Agreement dated as of March 2, 2005, among Enterprise Products Partners, L.P., Enterprise Products Operating L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.6 to Form 8-K filed on March 3, 2005).
4.33	Assumption Agreement dated as of September 30, 2004 between Enterprise Products Partners L.P. and GulfTerra Energy Partners, L.P. relating to the assumption by Enterprise of GulfTerra s obligations under the GulfTerra Series F2 Convertible Units (incorporated by reference to Exhibit 4.4 to Form 8-K/A-1 filed on October 5, 2004).
4.34	Statement of Rights, Privileges and Limitations of Series F Convertible Units, included as Annex A to Third Amendment to the Second Amended and Restated Agreement of Limited Partnership of GulfTerra Energy Partners, L.P., dated May 16, 2003 (incorporated by reference to Exhibit 3.B.3 to Current Report on Form 8-K of GulfTerra Energy Partners, L.P., file no. 001-11680, filed with the Commission on May 19, 2003).
4.35	Unitholder Agreement between GulfTerra Energy Partners, L.P. and Fletcher International, Inc. dated May 16, 2003 (incorporated by reference to Exhibit 4.L to Current Report on Form 8-K of GulfTerra Energy Partners, L.P., file no. 001-11680, filed with the Commission on May 19, 2003).
4.36	Indenture dated as of May 17, 2001 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and the Chase Manhattan Bank, as Trustee (filed as Exhibit 4.1 to GulfTerra s Registration Statement on Form S-4 filed June 25, 2001, Registration Nos. 333-63800 through 333-63800-20); First Supplemental Indenture dated as of April 18, 2002 (filed as Exhibit 4.E.1 to GulfTerra s 2002 First Quarter Form 10-Q); Second Supplemental Indenture dated as of April 18, 2002 (filed as Exhibit 4.E.2 to GulfTerra s 2002 First Quarter Form 10-Q); Third Supplemental Indenture dated as of October 10, 2002 (filed as Exhibit 4.E.3 to GulfTerra s 2002 Third Quarter Form 10-Q); Fourth Supplemental Indenture dated as of November 27, 2002 (filed as Exhibit 4.E.1 to GulfTerra s Current Report on Form 8-K dated March 19, 2003); Fifth Supplemental Indenture dated as of January 1, 2003 (filed as Exhibit 4.E.2 to GulfTerra s Current Report on Form 8-K dated March 19, 2003); Sixth Supplemental Indenture dated as of June 20, 2003 (filed as Exhibit 4.E.1 to GulfTerra s 2003 Second Quarter Form 10-Q, file no. 001-11680).

4.37	Seventh Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.E.1 to GulfTerra s Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.38	Indenture dated as of November 27, 2002 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee (filed as Exhibit 4.1 to GulfTerra s Current Report of Form 8-K dated

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Exhibit Number	Exhibit*
	December 11, 2002); First Supplemental Indenture dated as of January 1, 2003 (filed as Exhibit 4.1.1 to GulfTerra s Current Report on Form 8-K dated March 19, 2003); Second Supplemental Indenture dated as of June 20, 2003 (filed as Exhibit 4.1.1 to GulfTerra s 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.39	Third Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.1.1 to GulfTerra s Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.40	Indenture dated as of March 24, 2003 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee dated as of March 24, 2003 (filed as Exhibit 4.K to GulfTerra s Quarterly Report on Form 10-Q dated May 15, 2003); First Supplemental Indenture dated as of June 30, 2003 (filed as Exhibit 4.K.1 to GulfTerra s 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.41	Second Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.K.1 to GulfTerra s Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.42	Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Form 8-K filed on July 1, 2005).
4.43	Seventh Supplemental Indenture dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005).
4.44	Global Note representing $500,000,000 principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005).
4.45	Note Purchase Agreement dated as of December 15, 2005 among Cameron Highway Oil Pipeline Company and the Note Purchasers listed therein (incorporated by reference to Exhibit 4.1 to Form 8-K filed December 21, 2005.)
10.1	Transportation Contract between Enterprise Products Operating L.P. and Enterprise Transportation Company dated June 1, 1998 (incorporated by reference to Exhibit 10.3 to Registration Statement Form S-1/A filed July 8, 1998).
10.2	Seventh Amendment to Conveyance of Gas Processing Rights, dated as of April 1, 2004 among Enterprise Gas Processing, LLC, Shell Oil Company, Shell Exploration & Production Company, Shell Offshore Inc., Shell Consolidated Energy Resources Inc., Shell Land & Energy Company, Shell Frontier Oil & Gas Inc. and Shell Gulf of Mexico Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 26, 2004).
10.3***	Enterprise Products 1998 Long-Term Incentive Plan, amended and restated as of April 8, 2004 (incorporated by reference to Appendix B to Notice of Written Consent dated April 22, 2004, filed April 22, 2004).
10.4***	Form of Option Grant Award under 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.2 to Form S-8 Registration Statement, Reg. No. 333-115633, filed May 19, 2004).
10.5***	Form of Restricted Unit Grant under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.3 to Form S-8 Registration Statement, Reg. No. 333-115633, filed May 19, 2004).
10.6***	1998 Omnibus Compensation Plan of GulfTerra Energy Partners, L.P., Amended and Restated as of January 1, 1999 (incorporated by reference to Exhibit 10.9 to Form 10-K for the year ended December 31, 1998 of GulfTerra Energy Partners, L.P., file no. 001-11680); Amendment No. 1, dated as of December 1, 1999 (incorporated by reference to Exhibit 10.8.1 to Form 10-Q for the quarter ended June 30, 2000 of GulfTerra Energy Partners, L.P., file no. 001-116800); Amendment No. 2 dated as of May 15, 2003 (incorporated by reference to Exhibit 10.M.1 to Form 10-Q for the quarter ended June 30, 2003 of

	GulfTerra Energy Partners, L.P., file no. 001-11680).
10.7	Third Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated August 15, 2005, but effective as of February 24, 2005 (incorporated by reference to Exhibit 10.1 to Form 8-K filed August 22, 2005).

Exhibit Number	Exhibit*
10.8***	EPE Unit L.P. Agreement of Limited Partnership (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P., Commission file no. 1-32610, on September 1, 2005).
10.9***	Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to Amendment No. 3 to Form S-1 Registration Statement (Reg. No. 333-124320) filed by Enterprise GP Holdings L.P. on August 11, 2005).
10.10***	Form of Restricted Unit Grant under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.29 to Amendment No. 3 to Form S-1 Registration Statement (Reg. No. 333-124320) filed by Enterprise GP Holdings L.P. on August 11, 2005).
10.11***	Form of Phantom Unit Grant under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.30 to Amendment No. 3 to Form S-1 Registration Statement (Reg. No. 333-124320) filed by Enterprise GP Holdings L.P. on August 11, 2005).
10.12#	Waiver of Provisions of the Conflicts Policies and Procedures of the Third Amended and Restated Administrative Services Agreement dated February 23, 2006 but effective as of February 13, 2006.
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2005, 2004, 2003, 2002 and 2001.
18.1	Letter regarding Change in Accounting Principles dated May 4, 2004 (incorporated by reference to Exhibit 18.1 to Form 10-Q filed May 10, 2004).
21.1#	List of subsidiaries.
23.1#	Consent of Deloitte & Touche LLP.
31.1#	Sarbanes-Oxley Section 302 certification of Robert G. Phillips for Enterprise Products Partners L.P. for the December 31, 2005 annual report on Form 10-K.
31.2#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the December 31, 2005 annual report on Form 10-K.
32.1#	Section 1350 certification of Robert G. Phillips for the December 31, 2005 annual report on Form 10-K.
32.2#	Section 1350 certification of Michael A. Creel for the December 31, 2005 annual report on Form 10-K.

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P. is 1-14323.

*** Identifies management contract and compensatory plan arrangements.

\# Filed with this report.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on February 27, 2006.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)
By: Enterprise Products GP, LLC, as general partner

By: */s/ Michael J. Knesek*	Senior Vice President, Controller and Principal Accounting Officer
Michael J. Knesek	of the general partner

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on February 27, 2006.

Signature	Title (Position with Enterprise Products GP, LLC)
/s/ Dan L. Duncan Dan L. Duncan	Director and Chairman
/s/ Robert G. Phillips Robert G. Phillips	Director, President and Chief Executive Officer
/s/ Dr. Ralph S. Cunningham Dr. Ralph S. Cunningham	Director, Group Executive Vice President and Chief Operating Officer
/s/ Michael A. Creel Michael A. Creel	Director, Executive Vice President and Chief Financial Officer
/s/ Richard H. Bachmann Richard H. Bachmann	Director, Executive Vice President, Chief Legal Officer and Secretary
/s/ W. Randall Fowler W. Randall Fowler	Director, Senior Vice President and Treasurer
/s/ E. William Barnett E. William Barnett	Director
/s/ Philip C. Jackson Philip C. Jackson	Director
/s/ Steve L. Baum Steve L. Baum	Director
/s/ Michael J. Knesek Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer

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Index to Exhibits

The following exhibits have been filed with this report. The other exhibits required to be filed with this annual report have been incorporated by reference as indicated in the exhibit table found under Item 15 of this report beginning on page 176.

Exhibit Number	Description of Exhibit
10.12	Waiver of Provisions of the Conflicts Policies and Procedures of the Third Amended and Restated Administrative Services Agreement dated February 23, 2006 but effective as of February 13, 2006.
12.1	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2005, 2004, 2003, 2002 and 2001.
21.1	List of subsidiaries.
23.1	Consent of Deloitte & Touche LLP.
31.1	Sarbanes-Oxley Section 302 certification of Robert G. Phillips for Enterprise Products Partners L.P. for the December 31, 2005 annual report on Form 10-K.
31.2	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the December 31, 2005 annual report on Form 10-K.
32.1	Section 1350 certification of Robert G. Phillips for the December 31, 2005 annual report on Form 10-K.
32.2	Section 1350 certification of Michael A. Creel for the December 31, 2005 annual report on Form 10-K.