UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2004 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 (State or Other Jurisdiction of Incorporation or Organization)	**76-0568219** (I.R.S. Employer Identification No.)
2727 North Loop West, Houston, Texas (Address of Principal Executive Offices)	**77008** (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 whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No o

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).

Yes ☑ No o

The aggregate market value of the common units of *Enterprise Products Partners L.P.* ("EPD") held by non-affiliates at June 30, 2004, 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, 2004, was approximately $2.3 billion. This figure excludes common units beneficially owned by Dan L. Duncan, trusts established for the benefit of Mr. Duncan's family and directors and executive officers of Enterprise Products GP, LLC (our general partner) which are affiliates of EPD. There were 383,554,318 common units of EPD outstanding at March 15, 2005.

ENTERPRISE PRODUCTS PARTNERS L.P.
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Glossary

The following abbreviations, acronyms or terms used in this Form 10-K are defined below:

Acadian Gas	Acadian Gas, LLC and subsidiaries, acquired from Shell in April 2001
Administrative Services Agreement	Second Amended and Restated Administrative Services Agreement, effective as of October 1, 2004, among EPCO, the Company, the Operating Partnership, the general partner of the OLP and our Enterprise GP (formerly, the "EPCO Agreement")
AICPA	American Institute of Certified Public Accountants
Anadarko	Anadarko Petroleum Corporation, its subsidiaries and affiliates
APB	Refers to opinions or statements issued the Accounting Principles Board
ARB	Refers to Accounting Research Bulletins
ARO	Asset retirement obligations
BBtus	Billion British thermal units, a measure of heating value
BBtus/d	Billion British thermal units per day, a measure of heating value
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
BEF	Belvieu Environmental Fuels GP, LLC and Belvieu Environmental Fuels, L.P., collectively
Belle Rose	Belle Rose NGL Pipeline LLC, an equity investment
BHP	BHP Billiton Plc, its subsidiaries and affiliates
BP	BP PLC, its subsidiaries and affiliates
BRF	Baton Rouge Fractionators LLC, an equity investment
BRPC	Baton Rouge Propylene Concentrator, LLC, an equity investment
Cal Dive	Cal Dive International, Inc., its subsidiaries and affiliates
Cameron Highway	Cameron Highway Oil Pipeline Company, an equity investment
CAONO	Refers to "consideration adjustment outside of normal operations." For a discussion of CAONO, please read "*The Company's Operations – NGL Pipelines & Services — Natural Gas Processing and related NGL marketing activities*" beginning on page 18 of this annual report.
CEO	Chief Executive Officer
CFO	Chief Financial Officer
ChevronTexaco	ChevronTexaco Corp., its subsidiaries and affiliates
CMAI	Chemical Market Associates, Inc.
Cogeneration	Cogeneration is the simultaneous production of electricity and heat using a single fuel such as natural gas.
Company	Enterprise Products Partners L.P. and its consolidated subsidiaries, including the Operating Partnership (also referred to as "Enterprise")
ConocoPhillips	ConocoPhillips Petroleum Company, its subsidiaries and affiliates
Coyote	Coyote Gas Treating, LLC, an equity investment
CPG	Cents per gallon
Deepwater	Deepwater refers to oil and gas production areas located at depths of 1,000 feet or more such as those found in the Gulf of Mexico.
Deepwater Gateway	Deepwater Gateway, L.L.C., an equity investment
Devon	Devon Energy Corporation, its affiliates and subsidiaries
Diamond-Koch	Refers to common affiliates of both Valero Energy Corporation and Koch Industries, Inc.
Dixie	Dixie Pipeline Company, an equity investment
Dominion	Dominion Resources, Inc., its subsidiaries and affiliates
Dow	The Dow Chemical Company, its subsidiaries and affiliates
DRIP	Distribution Reinvestment Plan
Dynegy	Dynegy Inc., its subsidiaries and affiliates
EITF	Emerging Issues Task Force
El Paso	El Paso Corporation and its affiliates
Enbridge	Enbridge Inc., its subsidiaries and affiliates

Glossary (Continued)

Enterprise	Enterprise Products Partners L.P. and its consolidated subsidiaries, including the Operating Partnership
Enterprise GP	Enterprise Products GP, LLC, the general partner of the Company
EPA	Environmental Protection Agency
EPCO	EPCO, Inc. (formerly Enterprise Products Company), an affiliate of the Company and our ultimate parent company
EPIK	EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively
EPOLP	Enterprise Products Operating L.P., the operating subsidiary of the Company (also referred to as the "Operating Partnership")
Evangeline	Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively, an equity investment
ExxonMobil	Exxon Mobil Corporation, its subsidiaries and affiliates
FASB	Financial Accounting Standards Board
Feedstock	A raw material required for an industrial process such as in petrochemical manufacturing
FERC	Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation
Forward sales contracts	The sale of a commodity or other product in a current period for delivery in a future period.
FTC	U.S. Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States of America
GulfTerra	Enterprise GTM Holdings L.P., formerly named GulfTerra Energy Partners, L.P. (for a discussion of GulfTerra, please read "*The Company's Operations – Recent Developments*" beginning on page 2 of this annual report.)
GulfTerra GP	Enterprise GTMGP, L.L.C., formerly named GulfTerra Energy Company, L.L.C., the general partner of GulfTerra
GulfTerra Merger	Refers to Step One, Step Two and Step Three of the merger of GulfTerra with a wholly owned subsidiary of the Company and the various transactions related thereto. Please read Note 3 of the Notes to Consolidated Financial Statements for a description of Step One, Step Two and Step Three of the GulfTerra Merger.
HIOS	Denotes our High Island Offshore System
HSC	Denotes our Houston Ship Channel pipeline system
ICA	Interstate Commerce Act
Isomerization	For a discussion of the isomerization process, please read "*The Company's Operations—Petrochemical Services—Butane Isomerization*" beginning on page 32 of this annual report.
Kerr-McGee	Kerr-McGee Corporation, its subsidiaries and affiliates
Koch	Koch Industries, Inc. , its subsidiaries and affiliates
La Porte	La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively, an equity investment
LIBOR	London interbank offered rate
LCM	Lower of average cost or market
MBFC	Mississippi Business Finance Corporation
MBPD	Thousand barrels per day
Mid-America	Mid-America Pipeline Company, LLC
Midstream Energy Assets	The intermediate segments of the energy industry downstream of oil and gas production and upstream of end user consumption. These segments provide services to producers and consumers of energy. These services generally include but are not limited to natural gas gathering, processing and wholesale marketing and NGL fractionation, transportation and storage.
MMcf	Million cubic feet

Glossary (continued)

MMcf/d	Million cubic feet per day
MMBbls	Million barrels
MMBtus	Million British thermal units, a measure of heating value
Mont Belvieu	Mont Belvieu, Texas
Moody's	Moody's Investors Service
MTBE	Methyl tertiary butyl ether
Natural gas processing	For a discussion of our natural gas processing business, please read "*The Company's Operations—Natural Gas Processing and related NGL marketing activities*" beginning on page 18 of this annual report.
Nemo	Nemo Gathering Company, LLC, an equity investment
Neptune	Neptune Pipeline Company, L.L.C., an equity investment
NGL or NGLs	Refers to natural gas liquid(s), which are used by the petrochemical and refining industries to produce plastics, motor gasoline and other industrial and consumer products and also are used as residential, agricultural and industrial fuels.
NGL marketing activities	For a discussion of our NGL marketing activities, please read "*The Company's Operations—Natural Gas Processing and related NGL marketing activities*" beginning on page 18 of this annual report.
NGL fractionation	For a discussion of the NGL fractionation process, please read "*The Company's Operations—NGL Pipelines & Services—NGL fractionation*" beginning on page 26 of this annual report.
NYSE	New York Stock Exchange
OPIS	Oil Price Information Service
Operating Partnership	Enterprise Products Operating L.P. and its affiliates
OTC	Olefins Terminal Corporation
Petrochemical marketing	For a discussion of our petrochemical marketing activities, please read "*The Company's Operations—Petrochemical Services—Propylene fractionation*" beginning on page 29 of this annual report.
Poseidon	Poseidon Oil Pipeline Company, L.L.C., an equity investment
Promix	K/D/S Promix LLC, an equity investment
Propylene fractionation	For a discussion of the propylene fractionation process, please read "*The Company's Operations—Petrochemical Services—Propylene fractionation*" beginning on page 29 of this annual report.
PTR	Refers to "plant thermal reduction." For a discussion of PTR, please read "*The Company's Operations – Natural Gas Processing and related NGL marketing activities*" beginning on page 18 of this annual report.
Resource base	The gross assemblage of various geological bodies from which oil and natural gas reserves are produced.
Rocky Mountain	Referrers to the Rock Mountain region of the United States, primarily, Wyoming, Utah, Colorado, and New Mexico
SEC	U.S. Securities and Exchange Commission
Seminole	Seminole Pipeline Company
SFAS	Statement of Financial Accounting Standards issued by the FASB
Shell	Shell Oil Company, its subsidiaries and affiliates
Spinnaker	Spinnaker Exploration Co., its subsidiaries and affiliates
Splitter III	Refers to the propylene fractionation facility we acquired from Diamond-Koch
Spot market	Refers to a market where buyers and sellers consummate routine transactions where performance by both parties is short-term in nature and prices are based on market conditions at the time the transaction is executed.
Starfish	Starfish Pipeline Company, LLC, an equity investment
STMA	Refers to the South Texas midstream assets we purchase from El Paso in connection with Step Three of the GulfTerra Merger. Please read Note 3 of the Notes to Consolidated Financial Statements for a description of Step One, Step Two and Step Three of the GulfTerra Merger.

Glossary (Continued)

Straddle plants	A natural gas processing facility situated on a pipeline that is the sole inlet and outlet for the processing facility
Sun	Sunoco Inc., its subsidiaries and affiliates
Tennessee Gas Pipeline	Refers to a major interstate natural gas pipeline, which is owned by El Paso
Tension-leg platform	A floating platform, attached to the sea floor by tensile strength steel tube tendons, used for drilling and production in deepwater.
TEPPCO	TEPPCO Partners, L.P., its subsidiaries and affiliates
Throughput	Refers to the physical movement of volumes through a pipeline
Tri-States	Tri-States NGL Pipeline LLC, an equity investment
Unocal	Unocal Corporation, its subsidiaries and affiliates
Valero	Valero Energy Corporation, its subsidiaries and affiliates
VESCO	Venice Energy Services Company, LLC, an equity investment
Williams	The Williams Companies, Inc., its subsidiaries and affiliates
Wilprise	Wilprise Pipeline Company, LLC
1998 Trust	Duncan Family 1998 Trust, an affiliate of EPCO
1999 Trust	EPOLP 1999 Grantor Trust, a subsidiary of EPOLP
2000 Trust	Duncan Family 2000 Trust, an affiliate of EPCO

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES.

General

We are a leading North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids or NGLs, and crude oil, and we are an industry leader in the development of midstream infrastructure in the deepwater trend of the Gulf of Mexico. We have the only integrated North American midstream network that includes natural gas gathering, processing, transportation and storage; NGL fractionation (or separation), transportation, storage and import and export terminaling; and crude oil transportation and offshore production platform services. Our midstream network links producers of natural gas, NGLs and crude oil from the largest supply basins in the United States, Canada and the Gulf of Mexico with the largest consumers and international markets.

On September 30, 2004, we completed the GulfTerra Merger and related transactions. For additional information regarding these events, please read "*Recent Developments*" beginning on page 2 of this annual report.

As a result of the GulfTerra Merger, we have reorganized our business activities into four reportable business segments: Offshore Pipelines & Services, Onshore Natural Gas Pipelines & Services, NGL Pipelines & Services and Petrochemical Services. Business segments are components of a business about which separate financial information is available. These components are regularly evaluated by the CEO of Enterprise GP in deciding how to allocate resources and in assessing performance. Generally, financial information is required to be reported on the basis that it is used internally for evaluating segment performance and deciding how to allocate resources to segments. For a narrative of our business and properties by segment, please read "The Company's Operations" included within this Item 1 and 2 discussion.

We were formed as a limited partnership in 1998 (NYSE symbol, "EPD") to own and operate certain NGL related businesses of EPCO. We conduct substantially all of our business through our wholly owned Operating Partnership and its subsidiaries and joint ventures. We are owned 98% by our limited partners and 2% by our general partner, Enterprise GP. We and Enterprise GP are affiliates of EPCO, our ultimate parent company.

We do not have any employees. All of our management, administrative and operating functions are performed by employees of EPCO, pursuant to the Administrative Services Agreement. For a discussion of the Administrative Services Agreement, please read Item 13 of this annual report. Unless the context requires otherwise, references to "we," "us," "our," "the Company" or "Enterprise" are intended to mean the consolidated business and operations of Enterprise Products Partners L.P. and its subsidiaries. Our principal executive offices are located at 2727 North Loop West, Houston, Texas 77008 and our telephone number is (713) 880-6500.

Cautionary Statement Regarding Forward-Looking Information and Risk Factors

This annual report contains various forward-looking statements and information that are based on our beliefs and those of Enterprise GP, our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "intend," "could," "believe," "may" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor Enterprise 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. 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. When considering forward-looking statements, please read the section titled "*Risk Factors*" included under Item 7 of this annual report.

Business Strategy

Our business strategy is to:

- capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the deepwater and continental shelf areas of the Gulf of Mexico and in the Rocky Mountain region;
- maintain a balanced and diversified portfolio of midstream energy assets and expand this asset base through organic development 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.

Recent Developments

The following information summarizes our recent significant developments and transactions. For additional information regarding the capital projects described in this section, please read "*Our Liquidity and Capital Resources — Capital Spending*" included under Item 7 of this annual report.

GulfTerra Merger

On September 30, 2004, Enterprise and GulfTerra completed the merger of GulfTerra with a wholly owned subsidiary of Enterprise. Additionally, Enterprise completed certain other transactions related to the merger, including receipt of Enterprise GP's contribution of a 50% membership interest in GulfTerra GP, which was acquired by Enterprise GP from El Paso, and the purchase of certain midstream energy assets located in South Texas from El Paso. The aggregate value of the total consideration Enterprise paid or issued to complete the GulfTerra Merger was approximately $4 billion.

As a result of the GulfTerra Merger, GulfTerra and GulfTerra GP became wholly owned subsidiaries of Enterprise on September 30, 2004. On October 1, 2004, we contributed our ownership interests in GulfTerra and GulfTerra GP to our Operating Partnership, which resulted in GulfTerra and GulfTerra GP becoming wholly owned subsidiaries of our Operating Partnership.

The GulfTerra Merger transactions

The GulfTerra Merger occurred in several interrelated transactions as described below.

- *Step One*. On December 15, 2003, Enterprise 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, Enterprise accounted for its investment in GulfTerra GP using the equity method of accounting. The $425 million in funds required to complete Step One were borrowed under an Interim Term Loan and our pre-merger revolving credit facilities. This amount was fully repaid with the net proceeds from equity offerings completed during 2004. For additional information regarding changes in our debt obligations since December 31, 2003, please see Note 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.
- *Step Two*. On September 30, 2004, the GulfTerra Merger was consummated and GulfTerra and GulfTerra GP became wholly owned subsidiaries of Enterprise. 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 GP acquired El Paso's remaining 50% membership interest in GulfTerra GP for $370 million in cash paid to El Paso and the issuance of a

9.9% membership interest in Enterprise GP to El Paso. Subsequently, Enterprise 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 GP borrowed the foregoing $370 million from Dan Duncan LLC (which owns a membership interest in Enterprise GP), which obtained the funds from a loan from EPCO (which indirectly owns the remaining membership interests in Enterprise GP).

- Immediately prior to closing the GulfTerra Merger, Enterprise 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 (7,433,425 of which were owned by El Paso) were converted into 104,549,823 Enterprise common units (13,454,499 of which are held by El Paso) at the time of the consummation of the GulfTerra Merger.

- *Step Three*. Immediately after Step Two was completed, Enterprise acquired certain South Texas midstream assets from El Paso for $155.3 million in cash. Pursuant to written agreements, our purchase of the South Texas midstream assets was effective September 1, 2004.

In connection with the closing of the GulfTerra Merger, on September 30, 2004, our Operating Partnership borrowed an aggregate $2.8 billion under its new revolving credit facilities to fund its cash payment obligations under Step Two and Step Three of the GulfTerra Merger and related transactions, including the tender offers for GulfTerra's outstanding senior and senior subordinated notes. For additional information regarding the GulfTerra Merger, please read Note 4 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

In connection with the GulfTerra Merger, we are required under a consent decree to sell our 50% interest in Starfish, which owns the Stingray natural gas pipeline and related gathering pipelines and dehydration and other facilities located in south Louisiana and the Gulf of Mexico offshore Louisiana. In January 2005, we entered into a contract with a third party to sell this investment for approximately $41.2 million. We expect to close this sale during the first quarter of 2005. The sale requires FTC approval under the terms of the consent decree relating to the GulfTerra Merger and is subject to other customary closing conditions. Additionally, under the same consent decree, we were required to sell our undivided 50% interest in a Mississippi propane storage facility by December 31, 2004. We sold our interest in this facility during the fourth quarter of 2004.

Acquisition of El Paso's Interests in Enterprise and Enterprise GP by affiliates of EPCO

In January 2005, an affiliate of EPCO acquired a 9.9% membership interest in Enterprise GP and 13,454,499 Enterprise common units from El Paso for approximately $425 million in cash. As a result of these transactions, EPCO and its affiliates own 100% of the membership interests of Enterprise GP and approximately 37.4% of our total outstanding common units. El Paso no longer owns any interest in us or Enterprise GP.

Agreement with Atwater Valley Producers Group for Deepwater Platform and Gas Pipeline

In November 2004, we entered into an agreement with the Atwater Valley Producers Group (consisting of Anadarko, Dominion, Kerr-McGee, Spinnaker and Devon) for the dedication, processing and gathering of natural gas and condensate production from several natural gas fields in the Atwater Valley, DeSoto Canyon and Lloyd Ridge areas of the deepwater Gulf of Mexico. We will design, construct, install and own Independence Hub, a 105-foot deep-draft, semi submersible platform with a two-level production deck, which will be capable of processing 850 MMcf/d of natural gas. The platform, which is estimated to cost approximately $385 million, will be operated by Anadarko. Cal Dive is our 20% joint venture partner in the Independence Hub Platform project. Additionally, we will construct, own, and operate the 134-mile Independence Trail natural gas pipeline system, which will have a throughput capacity of approximately 850 MMcf/d of natural gas. The pipeline system, which is estimated to cost $280 million, will transport production from the Independence Hub platform to the Tennessee Gas Pipeline.

Rocky Mountain NGL pipeline expansion and related NGL fractionation projects

In January 2005, we started a project to expand our Mont Belvieu NGL fractionator to accommodate an expected increase in NGLs transported to Mont Belvieu from the Rocky Mountains area. Our Mont Belvieu facility's current fractionation capacity is up to 210 MBPD of mixed NGLs. This project, which is expected to be completed in the first quarter of 2006 at an estimated total cost of $34.2 million, will increase total fractionation capacity at this facility by 15 MBPD and reduce its energy utilization costs. Additionally, we are reviewing a proposal to construct a new NGL fractionator at our Mont Belvieu complex that could add an additional 60 MBPD of fractionation capacity at this industry hub.

Currently, the Rocky Mountain segment of our Mid-America pipeline system transports up to 225 MBPD of NGLs from the major producing basins in Wyoming, Utah, Colorado and New Mexico to the Hobbs station on the Texas-New Mexico border. The proposed Western Expansion Project would expand the NGL transportation capacity of this pipeline to 275 MBPD. Permitting, engineering and design work are in progress. We submitted a draft environmental assessment and plan of development to the appropriate regulatory agencies during the first quarter of 2005. Contingent upon receiving all required permits and regulatory approvals, construction could begin as early as the fourth quarter of 2005.

Acquisition of Indian Springs natural gas gathering and processing assets from El Paso

In January 2005, we paid El Paso $74.5 million for their membership interests in Teco Gas Gathering, LLC and Teco Gas Processing, LLC. As a result of this acquisition, we indirectly own an 80% equity interest in the 89-mile Indian Springs Gathering System and a 75% equity interest in the Indian Springs natural gas processing facility, both of which are located in East Texas. The Indian Springs processing facility has capacity to process up to 120 MMcf/d of natural gas and there is an idle 20 MMcf/d production train available for restart to support increases in natural gas volumes. The natural gas processed at the Indian Springs processing facility is sourced from the Indian Springs Gathering System, as well as our nearby Big Thicket Gathering System.

Non-Public Investigation by the Bureau of Competition of the Federal Trade Commission

On February 24, 2005, an affiliate of EPCO, Enterprise GP Holdings, L.P., acquired TEPPCO GP from Duke Energy Field Services, LLC. TEPPCO GP owns a 2% general partner interest in and is the general partner of TEPPCO. On March 11, 2005, the Bureau of Competition of the Federal Trade Commission delivered written notice to Enterprise GP Holdings, L.P.'s legal advisor that it was conducting a non-public investigation to determine whether Enterprise GP Holdings' acquisition of TEPPCO GP may substantially lessen competition. No filings were required under the Hart-Scott-Rodino Act in connection with Enterprise GP Holdings' purchase of TEPPCO GP. EPCO and its affiliates may receive similar inquiries from other regulatory authorities. EPCO and its affiliates, including us, intend to cooperate fully with any such investigations and inquiries.

Available Information

As an accelerated filer, we electronically file certain documents with the SEC. We file annual reports on Form 10-K; quarterly reports on Form 10-Q; 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 and related statements pertaining to equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, NW, 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, proxy and information statements, and other information regarding issuers 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 713-880-6500 for paper copies of these reports free of charge.

THE COMPANY'S OPERATIONS

As a result of the GulfTerra Merger, we have reorganized our business activities into four reportable business segments: (i) Offshore Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) NGL Pipelines & Services; and (iv) Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered and products produced and/or sold. Each of these segments is more fully discussed in the following sections.

We have revised our prior segment information in order to conform to the current business segment operations and presentation. For additional information regarding our business segments including revenues, gross operating margin (a non-GAAP financial measure) and assets, please read Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

OFFSHORE PIPELINES & SERVICES

We own or have an interest in (i) approximately 1,150 miles of offshore natural gas pipelines strategically located to serve production areas in some of the most active drilling and development regions in the Gulf of Mexico, (ii) approximately 800 miles of Gulf of Mexico offshore crude oil pipeline systems and (iii) seven multi-purpose offshore hub platforms located in the Gulf of Mexico, which are included in our Offshore Pipelines & Services business segment.

Offshore Natural Gas Pipelines

Our offshore natural gas pipeline systems provide for the gathering and transmission of natural gas from natural gas 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. In general, our offshore natural gas pipeline transportation agreements generate revenue for these systems based on transportation fees per unit of volume (typically in MMBtus) transported. These agreements tend to be long-term in nature, often involving life-of-reserve commitments with firm and interruptible components. Our offshore natural gas pipeline systems do not take title to the natural gas volumes they transport; rather, the shipper retains title and the associated commodity price risk.

Within their market area, our offshore natural gas pipelines compete with other pipelines (both regulated and unregulated systems) primarily on the basis of price (in terms of transportation fees) and connections to downstream markets. These systems 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.

Our offshore natural gas pipeline business is affected by natural gas exploration and production activities in these operating areas. If these exploration and production activities decline due to (i) the inability of producers to find economically viable reserves; (ii) a weakened domestic economy which lowers natural gas demand; or (iii) natural depletion of the gas production to which our natural gas pipelines are connected, then throughput volumes on these pipelines will decline, thereby affecting our earnings from these assets. We actively seek to offset the loss of volumes due to natural depletion by adding connections to new customers and gas production. In addition, we believe our offshore natural gas pipeline systems are positioned to benefit from expected increases in natural gas production from new deepwater developments in the Gulf of Mexico.

Our offshore natural gas pipeline systems are subject to various types of regulation. For a discussion of the general impact of governmental regulation on our business, please read "*The Company's Operations — Regulation and Environmental Matters*" beginning on page 34.

The following table summarizes our primary offshore natural gas pipeline assets at March 1, 2005. Our ownership interest in each pipeline is held either through a consolidated subsidiary or indirectly through a company in which we have an investment accounted for under the equity method. For additional information regarding our equity method investments, please read Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Offshore Natural Gas Pipelines	Length (Miles)	Our Ownership Interest
Manta Ray Gathering System	235	25.7%
High Island Offshore System (1)	204	100%
Viosca Knoll Gathering System (1)	162	100%
Green Canyon Laterals (1)	136	Various (2)
Anaconda Gathering System (1)	110	100%
Nautilus System	101	25.7%
East Breaks System (1)	85	100%
Phoenix Gathering System (1)	78	100%
Nemo Gathering System	24	33.9%
Falcon Gas Pipeline (1)	14	100%
Total offshore natural gas pipelines	1,149	

(1) Acquired as a result of the GulfTerra Merger on September 30, 2004.

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

The 1,149 miles of offshore natural gas pipelines shown in the preceding table excludes the Stingray and Triton natural gas pipelines owned by Starfish. In connection with the GulfTerra Merger, we are required under a consent decree to sell our 50% interest in Starfish. In January 2005, we entered into a contract with a third party to sell this investment for approximately $42.1 million. We expect to close this sale during the first quarter of 2005. The sale requires FTC approval under the terms of the consent decree relating to the GulfTerra Merger and is subject to other customary closing conditions

The following table shows the approximate capacity (on a net basis in accordance with our ownership interest) of each of our primary offshore natural gas pipeline systems and an estimate of capacity utilization for the periods in which we owned these assets.

Offshore Natural Gas Pipelines	Approximate Net Capacity (MMcf/d)	Estimated Average Utilization Rate (1)		
		2004	2003	2002
High Island Offshore System	1,800	40%(2)		
Viosca Knoll Gathering System	1,160	18%(2)		
Green Canyon Laterals	649	9%(2)		
Anaconda Gas Pipeline	400	21%(2)		
East Breaks System	400	54%(2)		
Phoenix Gathering System	450	27%(2)		
Falcon Gas Pipeline	400	49%(2)		
Other Gulf of Mexico Pipelines (3)	1,022	41%	41%	48%

(1) The estimated average utilization rate for each asset is based on a conversion factor where approximately 1,020 Btus of natural gas is equivalent to 1 cubic foot (“cf”) of natural gas.

(2) Utilization rates are for the three months that we owned these assets during 2004 (October through December). We acquired these assets as a result of the GulfTerra Merger.

(3) The approximate capacity shown for these pipelines includes 560 MMcf/d of net capacity for the Stingray pipeline, which is expected to be disposed of during the first quarter of 2005. This category also includes the approximate net throughput capacities of our Nautilus (154 MMcf/d), Manta Ray (206 MMcf/d) and Nemo (102 MMcf/d) natural gas gathering pipelines.

The following table reflects overall throughput rates of our offshore natural gas pipelines (on a net basis in accordance with our ownership interests) for the periods in which we owned them during 2004, 2003 and 2002.

The throughput rate for 2004 increased as a result of offshore natural gas pipeline assets acquired in the GulfTerra Merger on September 30, 2004.

	For the Year Ended December 31,		
	2004	2003	2002
Offshore natural gas pipeline throughput volume, net (BBtus/d)	2,081	433	500

The following is a brief description of each of our primary offshore natural gas pipeline assets, all of which we operate with the exception of the Manta Ray Gathering System, Nautilus System, Nemo Gathering System and certain components of the Green Canyon Laterals:

Manta Ray Gathering System. The Manta Ray Gathering System consists of natural gas gathering pipelines and related equipment located in the Gulf of Mexico offshore Louisiana. The Manta Ray 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 pipeline.

High Island Offshore System ("HIOS"). HIOS is an offshore natural gas transmission system that 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.

Viosca Knoll Gathering System. The Viosca Knoll Gathering System is a natural gas gathering system located off the coast of Louisiana that transports natural gas from producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico to several major interstate pipelines, including the Tennessee Gas Pipeline, Columbia Gulf, Southern Natural, Transco and Destin pipelines.

Green Canyon Laterals. The Green Canyon Laterals consist of 28 laterals, which are extensions of natural gas pipelines, located in the Gulf of Mexico offshore Texas and Louisiana. These laterals deliver natural gas to numerous downstream pipelines, including our HIOS system.

Anaconda Gathering System. The Anaconda Gathering System is a natural gas gathering system that connects our Marco Polo tension-leg platform and ChevronTexaco and BHP's Typhoon platform, both of which are located in the Green Canyon area of the Gulf of Mexico, to the ANR pipeline system.

Nautilus System. The Nautilus System consists of a natural gas pipeline system located in the Gulf of Mexico offshore Louisiana. Currently, the primary source of natural gas throughput for the Nautilus system is volume originating from our Manta Ray system. Natural gas volumes transported by the Nautilus system are delivered to our Neptune gas plant for processing.

East Breaks System. The East Breaks System is a natural gas gathering system that connects the Hoover-Diana deepwater platform, which is owned by affiliates of ExxonMobil and BP and located in Alaminos Canyon Block 25, to our HIOS natural gas pipeline system.

Phoenix Gathering System. The Phoenix Gathering System is a natural gas gathering system, which commenced operations in July 2004, connecting Kerr-McGee and Devon's Red Hawk platform located in the Garden Banks area of the Gulf of Mexico to the ANR pipeline system.

Nemo Gathering System. The Nemo Gathering System is a natural gas gathering pipeline located offshore Louisiana that transports natural gas volumes from Shell's Green Canyon developments to an interconnect with our Manta Ray Gathering System.

Falcon Gas Pipeline. The Falcon Gas Pipeline is a natural gas pipeline located off the Texas coast that delivers Pioneer Natural Resources' 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.

Offshore Crude Oil Pipelines

As a result of the GulfTerra Merger, we acquired interests in several offshore crude oil pipeline systems which are located in the vicinity of oil-producing areas in the Gulf of Mexico. Typically, these systems receive 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. In general, our oil pipeline systems generate revenue based on agreements resulting from purchasing and selling products at price differentials per unit of volume (typically in barrels) received. A substantial portion of the revenues generated by our oil pipeline systems are attributed to production from reserves committed under long-term contracts for the productive life of the relevant field or purchases and sales of crude oil with terms from two to twelve months. The rates we charge 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.

Cameron Highway's, Poseidon's and Typhoon's agreements require the purchase of producer's oil at the inlet of their pipelines for an index-based price, less a price differential. At the outlet of their pipelines, Cameron Highway, Poseidon and Typhoon sell the oil back to producers at the same index-based price. These transactions are recorded as net revenue.

Our offshore oil pipeline systems were built as a result of the need for additional crude oil capacity to receive and deliver new deepwater oil production to shore. Our competition includes other oil pipeline systems, built, owned and operated by producers to handle their own production and, as capacity is available, production for others. Our oil pipelines compete for new production on the basis of geographic proximity to the production, cost of connection, available capacity, transportation fees and access to onshore markets. In addition, the ability of our pipelines to access future reserves will be subject to our ability, or the producer's ability, to fund the significant capital expenditures required to connect to the new production. These pipeline systems exhibit little to no effects of seasonality; however, they may be affected by cyclical weather events such as hurricanes and tropical storms in the Gulf of Mexico.

Our offshore oil pipeline business is affected by crude oil exploration and production activities in these operating areas. If these exploration and production activities decline due to (i) the inability of producers to find economically viable reserves; (ii) a weakened domestic economy which lowers crude oil demand; or (iii) natural depletion of the crude oil production to which our oil pipelines are connected, then throughput volumes on these pipelines will decline, thereby affecting our earnings from these assets. We actively seek to offset the loss of volumes due to natural depletion by adding connections to new customers and oil production.

Our offshore crude oil pipeline systems are subject to various types of regulation. For a discussion of the general impact of governmental regulation on our business, please read "*The Company's Operations - Regulation and Environmental Matters*" beginning on page 34.

The following table summarizes our primary offshore oil pipeline assets at March 1, 2005. Our ownership interest in each pipeline is held either through a consolidated subsidiary or indirectly through a company in which we have an investment accounted for under the equity method. For additional information regarding our equity method investments, please read Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Offshore Crude Oil Pipelines	Length (Miles)	Our Ownership Interest
Cameron Highway Oil Pipeline	390	50%
Poseidon System	324	36%
Allegheny Oil Pipeline	43	100%
Marco Polo Oil Pipeline	36	100%
Typhoon Oil Pipeline	16	100%
Tarantula Oil Pipeline	4	100%
Total offshore crude oil pipelines	813	

The following table shows the approximate capacity (on a net basis in accordance with our ownership interest) of each of our primary offshore crude oil pipeline systems and an estimate of capacity utilization for the three month period (October 2004 through December 2004) in which we owned these assets.

Offshore Crude Oil Pipelines	Approximate Capacity, (MBPD, net)	Estimated Average Utilization Rate
Poseidon System	144	35%
Allegheny Oil Pipeline	135	26%
Marco Polo Oil Pipeline	120	19%
Typhoon Oil Pipeline	100	29%

The following table reflects overall throughput volumes of our offshore crude oil pipelines (on a net basis in accordance with our ownership interests) for the three-month period that we owned them during 2004 (October 2004 through September 2004).

	2004
Offshore crude oil pipeline throughput volume, net (MBPD)	138

The following is a brief description of each of our primary offshore crude oil pipeline assets, all of which we operate:

Cameron Highway Oil Pipeline. The Cameron Highway Oil Pipeline (“Cameron Highway”), which commenced operations during the first quarter of 2005, is designed to gather production from the deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in Port Arthur and Texas City, Texas.

Cameron Highway is supported by life of lease dedications with BP, BHP Billiton and Unocal for their production from the Holstein, Mad Dog and Atlantis fields and with Kerr McGee for its production from the Constitution and Ticonderoga fields. Additionally, Cameron Highway has contracted with Shell to purchase and sell its 50% share of crude oil production from the Holstein field. The Holstein field began producing in December 2004 and first production from the Mad Dog field commenced January 2005. Production from the Atlantis, Constitution and Ticonderoga fields is expected to begin in 2006.

Poseidon System. The Poseidon System is a major offshore sour crude oil pipeline system that gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico to onshore locations at Houma, Louisiana. The Poseidon System includes the newly constructed Front Runner Oil Pipeline, which is a 36-mile crude oil pipeline that connects the Front Runner field located in Green Canyon Blocks 338 and 339 in the central Gulf of Mexico with Poseidon’s main pipeline at Ship Shoal Block 332. The Front Runner Oil Pipeline received its first volumes from the Front Runner field in January 2005.

Allegheny Oil Pipeline. The Allegheny Oil Pipeline is an offshore crude oil pipeline system that connects the Allegheny and South Timbalier 316 platforms in the Green Canyon area of the Gulf of Mexico with our Poseidon System at the Ship Shoal 332 platform. Oil production from the Allegheny and South Timbalier 316 fields is committed to the Allegheny Oil Pipeline. In addition, the Allegheny Oil Pipeline receives crude oil production gathered from our Marco Polo Oil Pipeline.

Marco Polo Oil Pipeline. The Marco Polo Oil Pipeline is a newly constructed crude oil gathering system which gathers crude oil from our Marco Polo tension-leg platform to an interconnect with our Allegheny Oil Pipeline in Green Canyon Block 164.

Typhoon Oil Pipeline. The Typhoon Oil Pipeline is an offshore crude oil pipeline that connects ChevronTexaco and BHP’s Typhoon platform in the Green Canyon area of the Gulf of Mexico to Shell’s Boxer platform. The Shell Boxer platform provides access to our Poseidon System through a third-party pipeline.

Tarantula Oil Pipeline. The Tarantula Oil Pipeline is a newly constructed oil pipeline that connects the Tarantula field located in South Timbalier Block 308 in the central Gulf of Mexico to our Poseidon System. The Tarantula Oil Pipeline received its first volumes from the Tarantula field in January 2005.

Offshore Platforms

As a result of the GulfTerra Merger, we acquired 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 production 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.

Our platforms generally earn revenues through demand fees and commodity charges. A demand fee is typically a fixed-fee charged to a customer using our platform services regardless of the volume the customer delivers to the platform. A commodity charge is typically a fixed fee per MMcf of natural gas or barrel of crude oil, whichever the case may be, multiplied by the volume delivered to the platform by the customer. Contracts for platform services often include both demand fees and commodity charges, but demand fees generally expire after a contractual fixed period of time.

Offshore platforms are subject to similar competitive factors as our offshore natural gas and oil pipeline systems. These assets generally 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 in this business may possess greater capital resources than we have. Our platforms exhibit little to no effects of seasonality; however, they may be affected by cyclical weather events such as hurricanes and tropical storms in the Gulf of Mexico.

Our offshore platforms are affected by crude oil and natural gas exploration and production activities in these operating areas. If these exploration and production activities decline due to (i) the inability of producers to find economically viable reserves; (ii) a weakened domestic economy which lowers crude oil and natural gas demand; or (iii) natural depletion of the oil and gas fields to which they are connected, then processing volumes on these platforms will decline, thereby affecting our earnings from these assets. We actively seek to offset the loss of volumes due to natural depletion by adding connections to new customers and fields.

Our offshore platforms are subject to various types of regulation. For a discussion of the general impact of governmental regulation on our business, please read "*The Company's Operations - Regulation and Environmental Matters*" beginning on page 34.

The following table summarizes our primary offshore platform assets at March 1, 2005. Our ownership interest in each platform is held either through a consolidated subsidiary or indirectly through a company in which we have an investment accounted for under the equity method. For additional information regarding our equity method investments, please read Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Offshore Platforms	Water Depth (feet)	Acquired or Constructed	Our Ownership Interest
Marco Polo tension-leg platform	4,300	Constructed	50%
Viosca Knoll 817	671	Constructed	100%
Garden Banks 72	518	Constructed	50%
Ship Shoal 332 A and B	438	Acquired/Constructed	50%
East Cameron 373	441	Constructed	100%
Falcon Nest	389	Constructed	100%
Ship Shoal 331	376	Acquired	100%

The following table shows the approximate platform processing capacity (on a net basis in accordance with our ownership interest) of our primary offshore platforms and an estimate of capacity utilization for the three month period (October 2004 through December 2004) in which we owned these assets. Ship Shoal 332 A and B and 331 are excluded from this table since their primary functions are to serve as junction platforms for pipeline interconnects.

Offshore Platform	Approximate Capacity		Estimated Average Utilization Rate (1)	
	Natural Gas (MMcf/d, net)	Crude Oil (MBPD, net)	Natural Gas	Crude Oil
Marco Polo tension-leg platform	150	60	11%	19%
Viosca Knoll 817	140	5	1%	12%
Garden Banks 72	40	28	11%	3%
East Cameron 373	190	5	45%	10%
Falcon Nest	400	2	47%	38%

(1) The estimated average utilization rate for each asset is based on a conversion factor where approximately 1,020 Btus of natural gas is equivalent to 1 cubic foot (“cf”) of natural gas.

The following table reflects overall platform processing volumes of natural gas and crude oil of our offshore platforms (on a net basis in accordance with our ownership interest) for the three-month period that we owned them during 2004 (October 2004 through September 2004).

	Natural Gas (BBtus/d, net)	Oil (MBPD, net)
Offshore platform processing volumes, net	306	14

The following is a brief description of each of our primary offshore platform assets, all of which we operate with the exception of the Marco Polo tension-leg platform and Ship Shoal 332 A, East Cameron 373 and Ship Shoal 331 platforms:

Marco Polo. The Marco Polo tension-leg platform was installed in the first quarter of 2004 and commenced operations in July 2004. The Marco Polo tension-leg platform processes crude oil and natural gas from Anadarko’s Marco Polo field located in Green Canyon Block 608. Additionally, the Marco Polo tension-leg platform is expected to begin receiving production volumes from the K2 and K2 North fields during 2005.

Anadarko has dedicated 69,120 acres of property to the Marco Polo tension-leg platform, including acreage underlying their Marco Polo field, for the life of the reserves. Additionally, Anadarko has contracted with the Marco Polo tension-leg platform for firm gross processing capacity of 100 MBPD of crude oil and 150 MMcf/d of natural gas. The remainder of the platform’s oil processing capacity is contracted to Anadarko’s partners in the K-2 field. We have certain rights to get capacity back to market to third parties, if it becomes available. Anadarko is operator of the Marco Polo tension-leg platform.

Viosca Knoll 817. The Viosca Knoll 817 platform is centrally located on our Viosca Knoll Gathering System. This platform serves as a base for gathering deepwater production in the area, including ExxonMobil’s, Shell’s, and BP’s Ram Powell development. A 7,000 horsepower compressor on the platform facilitates deliveries from our Viosca Knoll Gathering System to multiple downstream interstate pipelines. The platform is also used as a base for crude oil and natural gas production from our Viosca Knoll Block 817 lease and Walter Oil and Gas’ Viosca Knoll 862 lease.

Garden Banks 72. The Garden Banks 72 platform serves as a base for landing deepwater production from Newfield Exploration Inc.’s Garden Banks Block 161 development, LLOG Exploration Offshore’s Garden Banks Block 378 lease and Amerada Hess Corporation’s Garden Banks Block 158 lease. The platform is also used as a junction platform for our Cameron Highway Oil Pipeline.

Ship Shoal 332 A and B. The Ship Shoal 332A platform serves as a junction platform for our Manta Ray and Nemo natural gas pipelines and our Poseidon and Allegheny oil pipelines. Enbridge operates the Ship Shoal 332A platform. The Ship Shoal 332B platform is connected to Ship Shoal 332A platform and is owned by Cameron Highway, our unconsolidated affiliate. The Ship Shoal 332B platform is a major junction platform for the Cameron

Highway Oil Pipeline and will also serve as the junction platform for the Constitution Oil Pipeline.

East Cameron 373. The East Cameron 373 platform serves as the host for Kerr-McGee's East Cameron Block 373 production and as the gathering site for production at Garden Banks Blocks 108, 152, 197, 200 and 201. Kerr-McGee operates the East Cameron 373 platform.

Falcon Nest. The Falcon Nest platform processes natural gas from Pioneer Natural Resources Company's Falcon, Harrier and Raptor fields. Pioneer has dedicated 69,120 acres of property to this platform for the life of the reserves.

Ship Shoal 331. The Ship Shoal 331 platform is used by Maritech Resources, Inc. to support production operations.

Major Construction Projects

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 and Lloyd Ridge areas (collectively, the "anchor fields") of the deepwater Gulf of Mexico. We will design, construct, and own Independence Hub, a 105-foot deep-draft, semi-submersible platform with a two-level production deck, which will be capable of processing 850 MMcf/d of natural gas. The platform, which is estimated to cost approximately $385 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 to sell them a 20% indirect interest in the Independence Hub platform. Under the terms of the agreement, we will have access to Cal Dive's fleet of vessels, which will assist us in the construction of the Independence Hub platform and the related export pipeline.

The Independence Hub platform will be located on Mississippi Canyon Block 920, in a water depth of 8,000 feet. This location was selected for the permanently anchored platform based on favorable seafloor conditions and proximity to the identified anchor fields. First production is expected in 2007. Under the terms of the agreement, the production fields served by the Independence Hub platform will include the dedicated anchor fields in addition to future discoveries on surrounding undeveloped blocks.

Additionally, we will construct, own, and operate the 134-mile Independence Trail natural gas pipeline system, which will have a throughput capacity of approximately 850 MMcf/d of natural gas. The pipeline system, which is estimated to cost $280 million, will transport production from the Independence Hub platform to the Tennessee Gas Pipeline. We entered into an agreement with Tennessee Gas Pipeline under which they will pay us $15 million for contributions in aid of construction to connect the Independence Trail natural gas pipeline system to their pipeline system. In November 2004, Tennessee Gas Pipeline reimbursed us $7 million for construction costs incurred. The balance of $8 million would be reimbursed by Tennessee Gas Pipeline when additional costs are incurred and is contingent upon our completion of the Independence Trail project, which is expected during 2006.

Constitution Gathering System. In July 2004, GulfTerra entered into a definitive agreement to construct, own, and operate oil and natural gas pipelines to provide production gathering services for the Constitution field, which is 100% owned by Kerr-McGee. The Constitution field is located at a depth of 5,300 feet in Green Canyon Blocks 679 and 680 in the Central Gulf of Mexico. The new $53.4 million natural gas pipeline will be a 32-mile, 16-inch pipeline with a transport capacity of up to 200 MMcf/d and will connect to our existing Anaconda Gathering System. The new $76.2 million oil pipeline will be a 70-mile, 16-inch pipeline with a minimum transport capacity of 80 MBPD that will connect with the Cameron Highway Oil Pipeline and Poseidon System at our Ship Shoal 332B platform. These pipelines are expected to start transporting volumes in the first half of 2006.

Intangible Assets

At December 31, 2004, the Offshore Pipelines & Services segment included $200 million of intangible assets primarily related to customer relationships. For information regarding our intangible assets, please read Note 8 of the Notes to Consolidated Financial Statements, which is included under Item 8 of this annual report.

ONSHORE NATURAL GAS PIPELINES & SERVICES

We own or have interests in 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, which are strategically located to serve the Northeast, Mid-Atlantic and Southeast domestic natural gas markets. This segment also includes leased 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 and Permian supply basins, 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. Generally, natural gas pipeline gathering or transportation agreements generate revenue for these systems based on a fee per unit of volume (generally in MMBtus) gathered or transported. Natural gas pipelines (such as our Acadian Gas and Alabama Intrastate systems) may also gather and 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, over 95% of the volumes handled by the San Juan Gathering System are fee-based arrangements, 80% of which are calculated as 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.

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 connected) to the customers we serve.

Our onshore natural gas pipeline business is affected by natural gas exploration and production activities. If these exploration and production activities decline due to (i) the inability of producers to find economically viable reserves; (ii) a weakened domestic economy which lowers natural gas demand; or (iii) natural depletion of the gas production to which they are connected, then throughput volumes on these pipelines will decline, thereby affecting our earnings from these assets. We actively seek to offset the loss of volumes due to natural depletion by adding connections to new customers and gas production.

Certain of our onshore natural gas pipelines (such as the Texas Intrastate System) are subject to regulation. For a discussion of the general impact of governmental regulation on our business, please read "*The Company's Operations - Regulation and Environmental Matters*" beginning on page 34.

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The following table summarizes our primary onshore natural gas pipeline systems at March 1, 2005. Our ownership interest in each pipeline is held either through a consolidated subsidiary or indirectly through a company in which we have an investment accounted for under the equity method. For additional information regarding our equity method investments, please read Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Onshore Natural Gas Pipelines	Length (Miles)	Our Ownership Interest
Texas Intrastate System (1)	8,222	100% (2)
San Juan Gathering System (1)	5,404	100%
Permian Basin System (1)	1,477	100%
Acadian Gas System	1,042	100% (3)
Alabama Intrastate System (1)	450	100%
Delmita Gathering System (1) (4)	295	100%
Big Thicket Gathering System (1) (4)	240	100%
Indian Springs Gathering System (5)	89	80%
Total onshore natural gas pipelines	17,219	

(1) These pipelines were acquired as a result of the GulfTerra Merger.

(2) The Texas Intrastate system includes some pipelines in which we own undivided interests.

(3) We own 100% of 1,015 miles of the Acadian Gas System and 49.5% of the related 27-mile Evangeline gas pipeline.

(4) These gathering systems are an integral part of our natural gas processing business, the results of operations and assets of which are accounted for under our NGL Pipelines & Services business segment.

(5) We acquired an ownership interest in this natural gas gathering system in January 2005.

The following table shows the approximate capacity (on a net basis in accordance with our ownership interest) of each of our primary onshore natural gas pipeline systems and an estimate of capacity utilization for the periods in which we owned these assets. The utilization rates for the assets we acquired in the GulfTerra Merger are for the three months that we owned them during 2004 (October through December).

Onshore Natural Gas Pipelines	Approximate Capacity (MMcf/d, net)	Estimated Average Utilization Rate (1) For the Year Ended December 31, 2004	2003	2002
Texas Intrastate System	4,975	61% (2)		
San Juan Gathering System	1,100	100% (2)		
Permian Basin System	470	72% (2)		
Acadian Gas System	954	66%	61%	72%
Alabama Intrastate System	200	77% (2)		

(1) The estimated average utilization rate for each asset is based on a conversion factor where approximately 1,020 Btus of natural gas is equivalent to 1 cubic foot ("cf") of natural gas.

(2) Utilization rates are for the three months that we owned these assets during 2004 (October through December). We acquired these assets as a result of the GulfTerra Merger.

The following table reflects overall throughput rates of our onshore natural gas pipelines (on a net basis in accordance with our ownership interest) for the periods in which we owned them during 2004, 2003 and 2002. The throughput rate for 2004 increased as a result of onshore natural gas pipeline assets acquired in the GulfTerra Merger on September 30, 2004.

	For the Year Ended December 31, 2004	2003	2002
Onshore natural gas pipeline throughput volume, net (BBtus/d)	5,638	600	701

The following is a brief description of each of our primary onshore natural gas pipeline assets, all of which we operate:

Texas Intrastate System. The Texas Intrastate System gathers and transports natural gas from supply basins in Texas and offshore in the Gulf of Mexico to local gas distribution companies and electric generation and industrial customers. This system has over 100 interconnections and serves important natural gas producing and market areas in Texas, including natural gas-fired electric plants and other key markets, such as Corpus Christi, the San Antonio/Austin area, the Beaumont/Orange area, and the large Houston Ship Channel industrial market. The Texas Intrastate System consists of the GulfTerra Texas Intrastate natural gas gathering system, the TPC Offshore natural gas gathering system and the Channel natural gas transmission pipeline.

The GulfTerra Texas Intrastate natural gas gathering system is one of the largest intrastate pipeline systems in the United States based on miles of pipe. This system consists of 7,292 miles of main lines, laterals and gathering lines and also includes some smaller pipelines in which we own undivided interests. The TPC Offshore natural gas gathering system consists of 197 miles of pipelines located in the coastal waters of south Texas. The TPC Offshore system also includes some smaller pipelines in which we own undivided interests. The Channel pipeline system is a 733-mile intrastate natural gas transmission system located along the Gulf Coast of Texas. We own a 50% undivided interest in the Channel natural gas transmission pipeline.

San Juan Gathering System. The San Juan Gathering System serves natural gas producers in the San Juan Basin of New Mexico and Colorado, where the system has connections to approximately 9,500 receipt points. This system gathers natural gas from wells in the San Juan Basin and delivers the natural gas to our Chaco natural gas processing facility and to Blanco natural gas processing facility owned by BP and ConocoPhillips. A project is currently underway to increase the capacity on the San Juan gathering system by 130 MMcf/d. The project was started in late 2003 and will be completed in stages through 2006.

Permian Basin System. The Permian Basin System gathers natural gas from numerous wells in the Permian Basin region of Texas and New Mexico and delivers the natural gas into the El Paso Natural Gas, Transwestern and Oasis pipelines. The Permian Basin System consists of the Waha Natural Gas Gathering System and Carlsbad Natural Gas Gathering System. The Waha system is a 674-mile natural gas gathering system located in the Permian Basin region of Texas. The Carlsbad system is a 803-mile natural gas gathering system located in the Permian Basin region of New Mexico.

Acadian Gas System. The Acadian Gas System consists of three natural gas pipelines: the 577-mile Cypress pipeline, 438-mile Acadian pipeline, and the 27-mile Evangeline pipeline. The Acadian Gas System is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. We also lease a natural gas storage cavern with approximately 3 Bcf of capacity that is an integral part of this system.

Alabama Intrastate System. The Alabama Intrastate System is a natural gas pipeline system that serves the coal bed methane-producing regions of Alabama. This system provides transportation and marketing services through the purchase of natural gas from regional producers and others, and sale of natural gas to local distribution companies and others.

Delmita Gathering System. The Delmita system is a natural gas gathering system located in South Texas that connects approximately 140 producing wells to our Delmita natural gas processing facility. This gathering system is an integral part of the natural gas processing operations of the Delmita facility, the results of operations and assets of which are accounted for under our NGL Pipelines & Services business segment.

Big Thicket Gathering System. The Big Thicket Gathering System, located in East Texas, gathers natural gas production from area fields and delivers the natural gas to our Indian Springs natural gas processing facility. This gathering system is an integral part of our Indian Springs natural gas processing operations, the results of operations and assets of which are accounted for under our NGL Pipelines & Services business segment.

Indian Springs Gathering System. In January 2005, we acquired Teco Gas Gathering, LLC from El Paso, which provided us with an indirect 80% interest in the Indian Springs Gathering System. The Indian Springs system consists of three gathering pipelines located in East Texas that gather natural gas production primarily from area fields and deliver the natural gas to our Indian Springs natural gas processing facility.

Natural Gas Storage Facilities

We own two underground salt dome natural gas storage facilities located near Hattiesburg, Mississippi that are strategically situated to serve the Northeast, Mid-Atlantic and Southeast natural gas markets. These two facilities have a combined current authorized working storage capacity of 13.5 Bcf, and are capable of delivering in excess of 1.2 Bcf/d of natural gas into five interstate pipeline systems: Transco, Destin Pipeline, Gulf South Pipeline, Southern Natural Gas Pipeline and Tennessee Gas Pipeline. We also lease a natural gas storage facility in Texas having 6.4 Bcf of working capacity and a salt dome natural gas cavern in Louisiana having a working gas storage capacity of 3 Bcf.

The ability of these facilities to handle high levels of injections and withdrawals of natural gas makes them well-suited for 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 also allow customers to take advantage of favorable natural gas prices and also provide customers the opportunity to quickly respond in situations where they have natural gas imbalance issues on pipelines connected to the storage facility. The characteristics of the salt domes at these facilities permit sustained periods of high delivery, the ability to quickly switch from full injection to full withdrawal and the ability to provide an impermeable storage medium.

Salt dome storage caverns such as those utilized at our Petal and Hattiesburg storage facilities experience a loss of working capacity of approximately 1% per year due to physical properties of the salt domes. Based on a recent volume verification test at Hattiesburg and recent pressure volume analysis at Petal, we believe the current working gas capacity at Petal and Hattiesburg is 10-15% lower than original capacity. We plan to address this normal loss of working capacity at our Petal and Hattiesburg storage facilities through a flooding program and we do not anticipate that this loss of capacity will affect our ability to provide services to our customers.

A large portion of the revenue generated by our Petal and Hattiesburg storage facilities is based on fixed monthly demand payments, which are paid regardless of the customer’s usage of the storage facilities. The remaining revenues are primarily generated based on a storage fee per unit of volume stored at these facilities. 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 gas-fired electric generation facilities due to the demand for electricity to power air conditioners.

Competition for natural gas storage is primarily based on location and the ability to deliver natural gas in a timely and reliable manner. Our Hattiesburg and Petal natural gas storage facilities are located in an area in Mississippi that effectively services the Northeastern, Mid-Atlantic and Southeastern natural gas markets, and these facilities have the ability to deliver all of their stored natural gas within a short duration. Our natural gas storage facilities compete with other means of natural gas storage, including other salt dome storage facilities, depleted reservoir facilities, and liquified natural gas and pipelines.

Most of our Petal storage facility’s working capacity is dedicated under a 20-year, fixed-fee contract. Most of the contracts relating to the Hattiesburg and Wilson natural gas storage facilities expire between 2005 and 2007. We believe that the location of our natural gas storage facilities allow us to compete effectively with other companies who provide natural gas storage services. We believe that many of our natural gas storage contracts will be renewed, although we also expect that once these firm storage contracts have expired, we will experience greater competition for providing storage services. The competition we experience will be dependent upon the nature of the natural gas storage market existing at that time. In addition to long-term contracts, we actively market interruptible storage services at the Petal facility to enhance our revenue generating ability beyond the firm storage contracts.

The following table summarizes the gross working gas authorized capacity of our primary natural gas storage facilities and our ownership interest in each facility as of March 1, 2005.

Natural Gas Storage Facilities	Gross (1) Capacity, (Bcf)	Our Ownership Interest
Petal	9.5	100%
Hattiesburg	4.0	100%
Wilson (2)	6.4	Leased
Acadian (3)	3.0	Leased

(1) Working gas is the volume of natural gas in the storage reservoir that can be extracted during the normal operation of the storage facility. This is the natural gas that is being stored and withdrawn. Working gas differs from “base gas” or “cushion gas,” which is the volume of gas that must remain in the storage facility to provide the minimum required pressurization to extract the working gas. The Petal working gas capacity is authorized by the FERC and the Hattiesburg working gas capacity is authorized by the Mississippi Oil and Gas Board.

(2) We lease the Wilson natural gas storage facility under an operating lease that expires in January 2008.

(3) We lease the Acadian natural gas storage cavern under an operating lease that expires in December 2012. This storage facility is an integral component of our Acadian Gas System.

The following is a brief description of each of our owned and leased natural gas storage facilities:

Petal. The Petal storage facility is located near Hattiesburg, Mississippi and consists of two high-deliverability natural gas storage caverns. The Petal facility has a current injection capacity in excess of 430 MMcf/d of natural gas and a withdrawal capacity of 895 MMcf/d of natural gas. The Petal capacity is 94% subscribed, with 7 Bcf dedicated under a 20-year fixed-fee contract to a subsidiary of The Southern Company and 1.65 Bcf subscribed to BP Energy Company. We are in the process of expanding this storage facility. For information regarding this expansion project, please read “Major Construction Projects — Petal Conversion Project” below.

Hattiesburg. The Hattiesburg storage facility is located less than one mile from the Petal storage facility and consists of three high-deliverability natural gas storage caverns. The facility has an injection capacity in excess of 175 MMcf/d of natural gas and a withdrawal capacity in excess of 400 MMcf/d of natural gas. The Hattiesburg capacity is currently fully subscribed, primarily with eleven contracts expiring between 2005 and 2007.

Wilson. The Wilson storage facility interconnects with our Texas Intrastate System and consists of four caverns. The facility, located in Wharton County, Texas, has an injection capacity of 150 to 360 MMcf/d of natural gas and a withdrawal capacity of 800 MMcf/d of natural gas. The Wilson capacity is currently 96% subscribed with contracts expiring between 2006 and 2007.

Acadian. The Acadian natural gas storage cavern is a rapid-cycle salt dome located in Assumption Parish, Louisiana that is an integral part of our Acadian Gas System. This storage facility has an injection capacity of 80 MMcf/d and a withdrawal capacity of 220 MMcf/d and is primarily used in the management of natural gas volumes on the Acadian Gas System; therefore, it is not generally used as a storage cavern for third-party customers.

Major Construction Projects

Petal Conversion Project. In the third quarter of 2004, we began to convert an existing brine well at our existing propane storage complex in Hattiesburg, Mississippi to natural gas service. This conversion, which is expected to cost $18 million, will create a new natural gas storage cavern with 1.8 Bcf of working gas capacity that will be integrated with our existing Petal natural gas storage facility. We expect to have the cavern in service during the second quarter of 2005. We have executed long-term storage agreements with BP for the entire capacity of the new natural gas storage cavern.

San Juan Optimization Project. In May 2003, we commenced a project relating to our San Juan Basin assets. This project, which is estimated to cost approximately $43 million, is expected to be completed in stages through 2006 and will result in increased capacity of up to 130 MMcf/d on our San Juan natural gas gathering system and increased market opportunities through a new interconnect at the tailgate of our Chaco plant.

Intangible Assets

At December 31, 2004, the Onshore Natural Gas Pipelines & Services segment included $425.8 million of intangible assets primarily related to customer relationships and other contract-based rights that we own. For information regarding our intangible assets, please read Note 8 of the Notes to Consolidated Financial Statements, which is included under Item 8 of this annual report.

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 12,775 miles and related storage facilities, which include our strategic Mid-America and Seminole NGL pipeline systems and (iii) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our import and export terminaling operations.

In general, 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 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 iso-octane and MTBE, and in the production of propylene oxide. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

Natural Gas Processing and related NGL marketing activities

At the core of our natural gas processing business are 24 processing plants located in Texas, Louisiana, Mississippi and New Mexico, 11 of which were acquired in connection with the GulfTerra Merger. In January 2005, we acquired Teco Gas Processing, LLC from El Paso, which provided us with an indirect 75% interest in the Indian Springs natural gas processing facility. The Indian Springs processing facility, which is located in Polk County, Texas, has capacity to process up to 120 MMcf/d of natural gas and there is an idle 20 MMcf/d production train available for restart to support increases in natural gas volumes. The natural gas processed at the Indian Springs processing facility is sourced from our Indian Springs Gathering System, which we also acquired an interest in from El Paso in January 2005, as well as our nearby Big Thicket Gathering System.

In general, 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 production from the deepwater Gulf of Mexico and the Rocky Mountains, thus far, has generally been rich in NGLs and typically must be processed to meet pipeline quality specifications. Deepwater natural gas production can yield in excess of 4 gallons of NGLs per Mcf of natural gas processed versus an approximate 1 to 1.5 gallons of NGLs per Mcf of production from the continental shelf areas of the Gulf of Mexico.

Our natural gas processing facilities can be categorized as two distinct types: (1) straddle plants situated on mainline natural gas pipelines owned either by us or by third parties or (2) field plants that process natural gas through associated gas gathering systems. 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 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.

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. Our integrated midstream energy asset system affords us flexibility in meeting our customers' needs. While many companies participate in the natural gas processing business, few have a presence in significant downstream activities such as NGL fractionation and transportation, import/export services and NGL marketing as we do. Our competitive position and presence in these downstream businesses allow us to extract incremental value while offering our customers enhanced services, including comprehensive service packages.

In general, we provide natural gas processing services under five types of arrangements: percent-of-liquids contracts, margin-band contracts, fee-based contracts, hybrid contracts (mixed percent-of-liquids and fee-based) and keepwhole contracts. The key features of each type of contract are described below:

- *Percent-of-liquids contracts.* Under this type of agreement, we receive a percentage of mixed NGLs extracted from a producer's natural gas stream. The producer either retains title to or receives the value associated with the remaining percentage of mixed NGLs extracted and is responsible for the cost of PTR (see below) with respect to 100% of the mixed NGLs extracted. We derive a profit from percent-of-liquids arrangements to the extent that revenues from our sale and delivery of the mixed NGLs we extracted exceed the sum of our plant operating costs and any other costs such as fractionation and pipeline fees that we might incur. At December 31, 2004, approximately 33% of the natural gas volumes we process were done so under percent-of-liquids contracts.

- *Margin-band contracts*. Under this type of agreement, we take ownership of mixed NGLs extracted from a producer's natural gas stream. In return, we pay the producer consideration based upon the energy value of the mixed NGLs we extract from the natural gas stream and that of the fuel consumed by our plant in the extraction process. Collectively, these energy values are referred to as plant thermal reduction ("PTR"). The consideration we pay to a producer is generally based on the price of natural gas multiplied by the quantity of PTR extracted or used; however, such consideration is reduced based on the total volume of gas that we process. We derive a profit from these arrangements to the extent that revenues from our sale and delivery of the mixed NGLs we extracted exceed the sum of the consideration (which may be further adjusted , see "CAONO" below) paid to the producer, our plant operating costs and any other costs such as fractionation and pipeline fees that we might incur. At December 31, 2004, approximately 26% of the natural gas volumes we process were done so under margin-band contracts.

  The most significant contract of this type affecting our natural gas processing business is the Shell agreement, which grants us the right to process Shell'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. This contract was amended effective April 1, 2004 to include (1) the reduction in consideration based upon the total volume of gas processed, and (2) a revision to the CAONO mechanism discussed below. In general, the amended contract includes the following rights and obligations:

  - the exclusive right, but not the obligation in all cases, to process substantially all of Shell's Gulf of Mexico natural gas production; plus

  - the exclusive right, but not the obligation in all cases, to process all natural gas production from leases dedicated by Shell for the life of such leases; plus

  - the right to all title, interest and ownership in the mixed NGLs extracted by our gas processing plants from Shell's natural gas production from such leases; with

  - the obligation to re-deliver to Shell the natural gas stream after any mixed NGLs are extracted.

  The amended contract contains a revised mechanism (termed "Consideration Adjustment Outside of Normal Operations" or "CAONO") to adjust the value of the consideration we pay to Shell. The revised

CAONO provides for an economic “floor” which, in conjunction with the reduction in consideration that we pay based on the total volume of gas processed, provides us with an acceptable return on the processing of Shell’s gas and provides Shell with relative assurance that its gas will continue to be processed during periods when gas processing economics are negative (times when we would normally choose not to process Shell’s gas). The revised CAONO also provides for an economic “ceiling” whereby Shell receives certain portions of the economic gain we realize when such gains reach certain threshold levels.

- *Fee-based contracts*. Under this type of agreement, we earn a fee based on the volume of natural gas we process. The producer either retains title to or receives the value associated with any mixed NGLs extracted and is responsible for all PTR costs. We derive a profit from fee-based arrangements to the extent that the fees we earn are greater than our plant operating costs. At December 31, 2004, approximately 18% of the natural gas volumes we process were done so under fee-based contracts.

- *Hybrid contracts*. Under this type of agreement, we typically provide processing services to a producer under a percent-of-liquids arrangement with the producer having a processing election on a monthly basis. In general, if a producer elects to not process under a percent-of-liquids arrangement, we process the natural gas under either a fee-based arrangement or in certain cases on a keepwhole basis if we realize greater economic gain. The intent of such arrangements is to give both producers and processors the incentive to process natural gas during periods of natural gas price volatility, especially during those periods when the price of natural gas is high relative to the economic value of NGLs. At December 31, 2004, approximately 14% of the natural gas volumes we process were done so under hybrid contracts.

- *Keepwhole contracts*. Under this type of agreement, we take ownership of mixed NGLs extracted from a producer’s natural gas stream and in return, we either return a quantity of natural gas with equivalent energy value as the PTR or pay the producer for the market value of the PTR. At December 31, 2004, approximately 9% of the natural gas volumes we process were done so under keepwhole contracts.

In general, our percent-of-liquids and 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.

As noted previously, under certain processing arrangements, we take title to a portion of the mixed NGLs that are extracted by our natural gas processing plants. Once this mixed NGL volume is fractionated into purity NGL products (ethane, propane, normal butane, isobutane and natural gasoline), we use them to meet contractual requirements or sell them on spot and forward markets as part of our NGL marketing activities. As part of these marketing activities, we have a number of isobutane sales contracts. To fulfill our obligations under these sales contracts, we can purchase isobutane on the open market for resale, sell isobutane from our inventory or pay our isomerization business (which is part of the Petrochemical Services segment) a toll processing fee to process our inventories of imported or domestically-sourced normal and mixed butanes into isobutane. The intersegment expense and revenue recorded as a result of utilizing the services of our isomerization business is eliminated in consolidation.

In support of its commercial goals, our NGL marketing activities within this segment 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 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 down through winter until the seasonal low is reached again.

To the extent that we are obligated under our margin-band/keepwhole gas processing contracts to pay compensation based upon or replace the PTR extracted from the natural gas stream, we are exposed to various risks, primarily commodity price fluctuations. 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.

Some of our exposure to commodity price risk is mitigated because natural gas with a high content of NGLs must be processed in order to meet pipeline quality specifications and to be suitable for ultimate consumption. To the extent that natural gas is not processed and does not meet pipeline quality specifications, this unprocessed natural gas and its associated crude oil production may be subject to being shut-in (i.e., not produced). Therefore, producers are motivated to reach contractual arrangements that are acceptable to gas processors in order for gas processing services to be available on a continuous basis (e.g., through contracts that do not expose the processors to natural gas price fluctuations). During periods of extreme commodity price fluctuations, we generally have the right under keepwhole arrangements to withhold processing services from a customer should we and the producer be unsuccessful in reaching acceptable contractual arrangements.

The following table lists our natural gas processing plants, total and net approximate processing capacities and our ownership interest in each facility at March 1, 2005. We operate the Toca, North Terrebonne, Calumet, Neptune, and Chaco facilities and all of the Texas plants.

Natural Gas Processing Facility	Location	Approximate Total Gas Processing Capacity (Bcf/d)	Our Ownership Interest (1)	Approximate Net Gas Processing Capacity (Bcf/d) (2)
Yscloskey	Louisiana	1.85	29.4%	0.54
Toca	Louisiana	1.10	60.3%	0.66
Venice	Louisiana	1.30	13.1%	0.17
North Terrebonne	Louisiana	1.30	44.3%	0.58
Calumet	Louisiana	1.60	31.5%	0.50
Blue Water	Louisiana	0.95	7.4%	0.07
Sea Robin	Louisiana	0.95	15.5%	0.15
Patterson II (3)	Louisiana	0.60	1.9%	0.01
Iowa	Louisiana	0.50	2%	0.01
Neptune	Louisiana	0.65	66%	0.43
Burns Point	Louisiana	0.16	50%	0.08
Pascagoula	Mississippi	1.50	40%	0.40
Chaco (4)	New Mexico	0.65	100%	0.65
Indian Basin (4)	New Mexico	0.24	42.3%	0.10
Thompsonville (4)	Texas	0.30	100%	0.30
Shoup (4)	Texas	0.29	100%	0.29
Gilmore (4)	Texas	0.26	100%	0.26
Armstrong (4)	Texas	0.25	100%	0.25
Matagorda (4)	Texas	0.25	100%	0.25
San Martin (4)	Texas	0.20	100%	0.20
Delmita (4)	Texas	0.15	100%	0.15
Shilling (4)	Texas	0.11	100%	0.11
Sonora (4)	Texas	0.10	100%	0.10
Indian Springs (5)	Texas	0.12	75%	0.09
Total natural gas processing facilities		15.38		6.35

(1) We own direct consolidated interests in all of our natural gas processing facilities with the exception of Venice, which is part of our equity 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 including volumes processed at facility, ownership interest, contractual arrangements and other factors.

(3) This facility was idled in December 2004.

(4) We acquired ownership interests in these facilities as a result of the GulfTerra Merger.

(5) We acquired our indirect ownership in this facility from El Paso in January 2005.

The following table shows our natural gas processing volumes and the corresponding overall utilization rates of our natural gas processing capacity for each of the last three years, with both amounts presented on a net basis in accordance with our ownership interests. The table also shows our equity NGL production for each of the last three years. Equity NGL production is defined as the volume of mixed NGLs extracted by the gas plants to which we take title under the terms of processing agreements or as a result of plant ownership interests.

	For Year Ended December 31,		
	2004	2003	2002
Net natural gas processing volume (Bcf/d)	3.89	2.06	2.15
Net natural gas processing capacity (Bcf/d)	6.35	3.26	3.37
Utilization rate	61%	63%	64%
Equity NGL production (MBPD)	129(2)	43(1)	73
Fee-based natural gas processing (MMcf/d)	1,692(2)	194	

(1) Equity NGL production rates for 2003 were adversely affected by high natural gas prices relative to the value of NGLs extracted. For additional information regarding natural gas and NGL prices, please read "*Selected Price and Volumetric Information*" in "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Our Results of Operations*" on page 49 of this annual report.

(2) Equity NGL production and fee-based natural gas processing volumes were positively impacted by improved processing economics during 2004 and the addition of processing assets in connection with the GulfTerra Merger.

At December 31, 2004, our NGL marketing activities utilize a fleet of approximately 569 railcars, the majority of which are under short and long-term leases. These railcars are used to deliver feedstocks to our facilities and to transport NGL products throughout the United States. We have rail loading/unloading facilities at Mont Belvieu, Texas; Breaux Bridge, Louisiana; Sorrento, Louisiana and Petal, Mississippi. These facilities service both our rail shipments and those of our customers.

NGL Pipelines

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. Our pipelines provide transportation services to customers on a fee basis. Therefore, 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 our NGL and petrochemical marketing activities, which are eliminated in consolidation). Typically, our NGL pipelines do not take title to the products they transport; rather, the shipper retains title and the associated commodity price risk.

In the markets we serve, we compete with a number of intrastate and interstate liquids pipeline companies (including those affiliated with major oil, petrochemical and gas companies) and barge, rail and truck fleet operators. In general, our NGL pipelines compete with these entities in terms of transportation fees and service. We believe that our pipeline systems offer significant flexibility in rendering transportation services for our customers due to the large number of receipt and delivery points that we can offer to them.

Taken as a whole, this business area has not exhibited a significant degree of seasonality. However, propane transportation volumes are generally higher in the October through March timeframe due to increased use of propane for heating in the upper Midwest and southeastern United States. In addition, our NGL pipeline systems are subject to various types of regulation. For a discussion of the general impact of governmental regulation on our business, please read "*The Company's Operations — Regulation and Environmental Matters*" beginning on page 34.

The following table summarizes our primary NGL pipeline transportation and distribution networks at March 1, 2005. Our ownership interest in each pipeline is held either through a consolidated subsidiary or indirectly through a company in which we have an investment accounted for under the equity method. For additional information regarding our equity method investments, please read Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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NGL Pipelines	Length in Miles	Our Ownership Interest
Mid-America Pipeline System	7,226	98%
Dixie	1,301	65.9% (1)
Seminole	1,281	88.4% (2)
Texas NGL System (3)	1,039	100%
Louisiana Pipeline System	655	Various (4)
Promix (5)	410	50%
Lou-Tex NGL	206	100%
HSC	266	100%
Tri-States	169	66.7% (6)
Chunchula	143	100%
Belle Rose	48	41.7%
Wilprise	30	74.7%
Total NGL pipelines	12,774	

(1) We acquired an additional 46.1% ownership interest in Dixie from ConocoPhillips (20%) and ChevronTexaco (26.1%) in January and February 2005, respectively.

(2) We acquired an additional 10% ownership interest in Seminole from ChevronTexaco in May 2004.

(3) Acquired as a result of the GulfTerra Merger on September 30, 2004.

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

(5) The Promix gathering pipeline is an integral component of the NGL fractionation activities of Promix. We acquired an additional 16.7% ownership interest in Promix from Koch in December 2004.

(6) We acquired an additional 16.7% ownership interest in Tri-States from Koch in April 2004.

NGL pipeline utilization

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. As shown in the following table, the utilization rates of our primary NGL pipelines are measured in terms of throughput (on a net basis in accordance with our ownership interest).

NGL Pipelines	Net Throughput Volumes (in MBPD) For Year Ended December 31, 2004	2003	2002
Mid-America Pipeline System (1)	614	580	641
Dixie	21	21	21
Seminole (1)	235	194	202
Texas NGL System (2)	38		
Louisiana Pipeline System	216	190	179
Lou-Tex NGL	20	36	38
HSC (3)	135	136	134
Tri-States, Wilprise and Belle Rose	61	35	44
Chunchula	3	4	5
Total net volume of NGL pipelines	1,343	1,196	1,264

(1) We acquired ownership interests in these systems in July 2002. The 2002 throughput rates reflect the five-month period that we owned interests in these assets (August 2002 through December 2002).

(2) We acquired the Texas NGL System in connection with the GulfTerra Merger on September 30, 2004. The 2004 throughput rates reflect the three-month period that we owned this system (October 2004 through December 2004).

(3) Throughput volumes for 2004 include 22 MBPD from the 91 miles of NGL pipeline acquired with our Morgan's Point facility in December 2004. Throughput rates are reflective of the period of time that we owned the assets.

The following is a brief description of each of our primary NGL pipeline assets, all of which we operate except for Dixie, Tri-States and a small portion of the Louisiana Pipeline System.

Mid-America Pipeline System. The Mid-America Pipeline System (or “Mid-America”) is a regulated NGL pipeline system consisting of three NGL pipelines: the 2,548-mile Rocky Mountain pipeline, the 2,740-mile Conway North pipeline, and the 1,938-mile Conway South pipeline. The Mid-America system crosses thirteen states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin.

The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs hub located on the Texas-New Mexico border. The Conway North segment links the large 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 pipeline connections. The Conway South pipeline connects the Conway hub with Kansas refineries and transports NGLs from Conway, Kansas to the Hobbs hub (with interconnections to the Seminole Pipeline System at the Hobbs hub). We also own fifteen unregulated propane terminals that are an integral part of the Mid-America 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.

Dixie. The Dixie pipeline is a regulated propane pipeline system extending from Mont Belvieu, 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. We purchased a 26.1% interest in Dixie from an affiliate of ChevronTexaco in February 2005 for $40 million, and a 20% interest in Dixie from an affiliate of ConocoPhillips in January 2005 for $31 million. As a result of these acquisitions, Dixie will be a consolidated subsidiary of ours beginning with the first quarter of 2005.

Seminole. Seminole is a regulated pipeline that transports mixed NGLs and NGL products from the Hobbs hub on the Texas-New Mexico border and the Permian Basin area to Mont Belvieu, Texas. The Seminole pipeline is interconnected with the Mid-America system at the Hobbs hub. The primary source of throughput for Seminole is the volume originating from the Mid-America system. In general, volumes transported by Seminole are ultimately used by petrochemical plants that manufacture various products in southeast Texas.

Texas NGL 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 fractionation facilities. The pipeline system also includes approximately 660-miles of pipelines that deliver NGL products 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.

Louisiana Pipeline System. The Louisiana Pipeline System is a network of nine NGL pipelines located in Louisiana. This system transports mixed NGLs and NGL products originating in southern Louisiana and Texas and serves a variety of customers including major 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.

Promix. The Promix pipeline is a NGL pipeline system that gathers mixed NGLs from 12 natural gas processing plants in Louisiana for delivery to the Promix NGL fractionator. This pipeline system is an integral part of the Promix NGL fractionation facility.

Lou-Tex NGL. The Lou-Tex NGL pipeline system is used to provide transportation services for NGL products 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.

HSC. The HSC pipeline system is a collection of NGL and petrochemical pipelines extending from our Houston Ship Channel import/export terminal facility and Morgan's Point Facility to Mont Belvieu, Texas. These pipelines are used to deliver NGL products to third-party petrochemical plants and refineries as well as to deliver feedstocks to our Mont Belvieu facilities. Additionally, the HSC pipeline system includes 91 miles of NGL pipeline acquired with our Morgan's Point facility in December 2004.

Tri-States, Belle Rose and Wilprise. The Tri-States, Belle Rose and Wilprise NGL pipelines supply mixed NGLs to the BRF, Norco and Promix NGL fractionators located in Louisiana. The mixed NGLs transported on these systems originate from gas processing facilities located along the Mississippi, Alabama and Louisiana Gulf Coast.

Chunchula. The Chunchula pipeline system is a NGL pipeline system extending from the Alabama-Florida border to our NGL storage facilities at Petal, Mississippi for further distribution.

NGL and related product storage

Our NGL and related product storage facilities are integral parts of our operations. In general, our underground storage wells are used to store mixed NGLs, NGL products and petrochemical products for customers and ourselves. The profitability of our storage operations is primarily dependent upon the volume of material stored and the level of fees charged.

We operate our 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 down for heating needs.

The following table summarizes gross working capacity of our primary storage assets and our ownership of such capacity (on a net basis in accordance with our ownership interest) in each by state as of March 1, 2005. We operate all of our owned or leased storage facilities, with the exception of certain assets operated for us by Shell in Louisiana and Mississippi.

NGL and Related Product Storage Assets by State	Utilized Working Capacity, MMBbls	Our Ownership of Working Capacity, MMBbls
Texas (1)	113.9	95.5
Louisiana	31.0	16.8
Mississippi (2)	10.9	10.9
Iowa	0.5	0.5
Nebraska	0.3	0.3
Oklahoma	0.1	0.1
Total NGL and Related Product storage capacity	156.7	124.1

(1) The 113.9 MMBbls of working capacity that we utilize in Texas includes 18.1 MMBbls held under operating leases assumed as a result of the GulfTerra Merger.

(2) In connection with the GulfTerra Merger, we were required by the FTC to sell our pre-merger undivided 50% ownership in a Hattiesburg, Mississippi propane storage facility by December 31, 2004. We sold our interest in this facility during the fourth quarter of 2004.

We store NGL and petrochemical products for customers in our storage facilities for a fee. The amount of storage capacity available for third party customer storage activity varies daily depending on our plant processing storage requirements. At times, we provide some of our processing customers with short-term storage services (typically 30 days or less) at nominal fees when they cannot take immediate delivery of products. Segment revenues include fees charged to our NGL and petrochemical product marketing activities for their use of the storage facilities. These intrasegment revenues and offsetting expenses are eliminated in financial statement consolidation.

Our competitors in this area are integrated major oil companies, chemical companies and other storage and pipeline companies. Major oil and gas companies occasionally use their proprietary storage assets to store for third party customers, thereby entering into competition with us and other storage capacity providers. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections and operational dependability.

NGL import and export facilities

We lease and operate NGL import and export facilities and own a barge dock located on the Houston Ship Channel in southeast Texas. Our import facility enables NGL tankers to be offloaded at their maximum unloading rate of 10,000 barrels per hour, thus minimizing the amount of time that a tanker is idle and increasing the number of vessels that can be offloaded. This NGL import facility is primarily used to offload volumes bound for our NGL storage and processing facilities near Mont Belvieu, Texas. In addition, we own an NGL export facility located at the same terminal as our import facility. Our export facility includes an NGL products chiller and related equipment used for loading refrigerated marine tankers for third-party export customers. Our export facility can load vessels with refrigerated propane and butane at rates up to 5,000 barrels per hour. In December 2004, we acquired a barge dock having the capability to load or unload two barges simultaneously, at a maximum load-out rate of approximately 5,000 barrels per hour. Our combined NGL import and export volumes for the years ended December 31, 2004, 2003 and 2002 were 69 MBPD, 79 MBPD and 41 MBPD, respectively.

Our import and export operations compete with those operated by Dow, Dynegy and ChevronTexaco primarily in terms of loading and offloading volumes per hour. Our competitive position is enhanced because of our related storage and pipeline assets at Mont Belvieu, which allow us to load and offload ships very efficiently. The profitability of import and export activities primarily depends upon the available quantities of NGLs to be loaded and offloaded and the fees we charge associated with each service. 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.

NGL Fractionation

NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, normal butane, isobutane, normal butane and natural gasoline. 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. 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 such as ethane may be reduced. This leads to a reduction in volumes available for NGL fractionation. The increase or decrease in NGL recovery levels is a primary factor behind changes in gross fractionation volumes.

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. These gas processing plants are expected to benefit from anticipated increases in natural gas production from emerging deepwater developments in the Gulf of Mexico offshore Louisiana and in the Rockies. Deepwater natural gas production has historically had a higher concentration of NGLs than continental shelf or domestic land-based production along the Gulf Coast. In addition, through connections with our Mid-America and Seminole pipeline systems, our Mont Belvieu NGL fractionator has access to NGLs from additional major supply basins in North America, including the San Juan Basin NGL production areas. Lastly, 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 to 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 whereby we retain a percentage of the NGLs we fractionate for them as our payment. 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. Overall, the NGL fractionation business exhibits little to no seasonal variation.

Although competition for NGL fractionation services is primarily based on the fractionation fee, the ability of an NGL fractionator to obtain mixed NGLs and distribute NGL products is also an important competitive factor and is a function of the existence of the necessary pipeline and storage infrastructure. NGL fractionators connected to extensive transportation and distribution systems such as ours have direct access to larger markets than those with less extensive connections.

The following table summarizes our primary NGL fractionation assets at March 1, 2005. Our ownership interest in each NGL fractionator is held either through a consolidated subsidiary or indirectly through a company in which we have an investment accounted for under the equity method. For additional information regarding our equity method investments, please read Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

NGL Fractionation Facility	Location	Total Plant Capacity, MBPD	Our Ownership Interest	Net Capacity, MBPD
Mont Belvieu	Texas	210	75.0%	158
South Texas (1)				
Shoup	Texas	69	100.0%	69
Armstrong	Texas	17	100.0%	17
Delmita	Texas	10	100.0%	10
Promix	Louisiana	145	50.0%(2)	73
Norco	Louisiana	75	100.0%	75
BRF	Louisiana	60	32.2%	19
VESCO	Louisiana	36	13.1%	5
Tebone	Louisiana	30	44.3%	13
Total Capacity		652		439

(1) Acquired as a result of the GulfTerra Merger. This list excludes the Almeda NGL fractionation facility (24 MBPD of capacity) that was acquired in connection with the GulfTerra Merger. At present, we have no plans to resume operations at the Almeda location.

(2) We acquired an additional 16.7% interest in Promix in December 2004.

NGL fractionator utilization

The following table shows fractionation volumes and capacity (on a net basis in accordance with our ownership interest) and the corresponding overall utilization rates of our primary NGL fractionation facilities for the last three years. Net capacity amounts have been adjusted for the timing of acquisitions and facility closures.

NGL Fractionation Facility	For Year Ended December 31, 2004	2003	2002
Mont Belvieu	137	134	127
South Texas	71		
Promix	20	24	30
Norco	57	42	41
BRF	15	11	17
Other	7	16	20
Total net volume (MBPD)	307	227	235
Net capacity (MBPD)	439	324	313
Utilization rate	70%	70%	75%

The following is a brief description of our primary NGL fractionation assets, all of which we operate except for VESCO.

Mont Belvieu. The Mont Belvieu NGL fractionator is one of the largest NGL fractionation facilities in the United States with a gross processing capacity of 210 MBPD. Our facility is located at Mont Belvieu, Texas, which is a key hub of the domestic and international NGL industry. Our Mont Belvieu 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 U.S. Gulf Coast. Our Mont Belvieu NGL fractionation facility is supported by long-term fractionation agreements, which accounted for 102 MBPD of net volume in 2004.

South Texas. The South Texas NGL fractionation facilities (Armstrong, Delmita and Shoup) have a combined capacity of 96 MBPD. These facilities physically occupy the same pad sites as certain of our South Texas natural gas processing facilities. Primarily all of the NGLs fractionated at these facilities are supplied directly from the South Texas NGL processing facilities.

Promix. Promix owns a 145 MBPD NGL fractionation facility located near Napoleonville, Louisiana. We acquired an additional 16.7% interest in Promix in December 2004, resulting in an increase in our ownership interest to 50%. Promix owns a 410-mile mixed NGL gathering system connected to twelve natural gas processing plants, five NGL storage caverns and a barge loading facility. Promix also 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 pipelines.

Norco. The Norco NGL fractionation facility, located in Norco, Louisiana, has a gross capacity of 75 MBPD. Our Norco facility receives mixed NGLs via pipeline from refineries and natural gas processing plants, including the Yscloskey and Toca natural gas processing plants in Louisiana. A portion of the mixed NGLs fractionated at our Norco facility are done so under percent-of-liquids contracts with the remainder of volumes fractionated under a fee-based contract. During 2004, long-term percent-of-liquids contracts exclusive to this facility accounted for approximately 51 MBPD of processing volume.

BRF. The BRF NGL fractionation facility, located near Baton Rouge, Louisiana, has a gross capacity of 60 MBPD. The BRF facility processes mixed NGLs provided by the co-owners of the facility (Williams, BP and ExxonMobil) from production areas in Alabama, Mississippi and southern Louisiana including offshore Gulf of Mexico areas.

VESCO. As a result of our VESCO investment, we own a 13.1% interest in a 36 MBPD NGL fractionator located in Plaquemines Parish, Louisiana.

Tebone. The Tebone NGL fractionation facility, located in Ascension Parish, Louisiana, has a gross capacity of 30 MBPD. Our Tebone facility receives mixed NGLs from the North Terrebonne gas processing plant.

Major Construction Projects

Rocky Mountain NGL pipeline expansion and related NGL fractionation projects

In January 2005, we started a project to expand our Mont Belvieu NGL fractionator to accommodate an expected increase in NGLs transported to Mont Belvieu from the Rocky Mountains area. Our Mont Belvieu facility's current fractionation capacity is up to 210 MBPD of mixed NGLs. This project, which is expected to be completed in the first quarter of 2006 at an estimated total cost of $34.2 million, will increase total fractionation capacity at this facility by 15 MBPD and reduce its energy utilization costs. Additionally, we are reviewing a proposal to construct a new NGL fractionator at our Mont Belvieu complex that could add an additional 60 MBPD of fractionation capacity at this industry hub.

Currently, the Rocky Mountain segment of our Mid-America pipeline system transports up to 225 MBPD of NGLs from the major producing basins in Wyoming, Utah, Colorado and New Mexico to the Hobbs station on the Texas-New Mexico border. The proposed Western Expansion Project would expand the NGL transportation capacity of this pipeline to 275 MBPD. Permitting, engineering and design work are in progress. We submitted a draft environmental assessment and plan of development to the appropriate regulatory agencies during the first quarter of 2005. Contingent upon receiving all required permits and regulatory approvals, construction could begin as early as the fourth quarter of 2005.

Intangible Assets

At December 31, 2004, the NGL Pipelines & Services segment included $303.5 million of intangible assets primarily related to customer relationships and other contract-based rights that we own. For information regarding our intangible assets, please read Note 8 of the Notes to Consolidated Financial Statements, which is included under Item 8 of this annual report.

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 various petrochemical pipeline systems.

Propylene fractionation

Our propylene fractionation business consists primarily of four propylene fractionation facilities located in Texas and Louisiana, and approximately 460 miles of various propylene pipeline systems. 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. Overall, the propylene fractionation business exhibits little seasonality.

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. Each of our petrochemical marketing competitors has varying levels of financial and personnel resources and competition generally revolves around price, service, logistics and location.

The following table summarizes our primary propylene fractionation assets and ownership at March 1, 2005. Our ownership interest in each propylene fractionation facility is held either directly through a consolidated subsidiary or indirectly through a company in which we have an investment accounted for under the equity method. For additional information regarding our equity method investments, please read Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Propylene Fractionation Facility	Location	Total Plant Capacity, MBPD	Our Ownership Interest	Net Capacity, MBPD
Mont Belvieu:				
Splitter I	Texas	17	54.6%(1)	17
Splitter II	Texas	14	100.0%	14
Splitter III	Texas	41	66.7%	27
Total Mont Belvieu		72		58
BRPC	Louisiana	23	30.0%	7
Total Capacity		95		65

(1) We own a 54.6% interest in Splitter I. We lease the remaining 45.4% interest in this facility from an affiliate of Shell.

The following is a brief description of our primary propylene fractionation assets, all of which we operate:

Mont Belvieu. We operate three polymer grade propylene fractionation facilities (Splitters I, II and III) in Mont Belvieu, Texas having a combined net capacity of 58 MBPD. Results of operations for our polymer grade propylene plants are generally dependent upon toll processing arrangements and petrochemical marketing activities. Under toll processing arrangements, we are paid fees based on the volume of refinery grade propylene used to produce polymer grade propylene.

As part of the petrochemical marketing activities associated with Splitters I, II, and III, we have several long-term polymer grade propylene sales agreements, the largest of which is with an affiliate of Shell. 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. During 2004, 11 MBPD of our net polymer grade propylene production was associated with toll processing operations with the balance attributable to petrochemical marketing activities.

BRPC. BRPC is a 23 MBPD chemical grade propylene production facility located near Baton Rouge, Louisiana. This unit, located across the Mississippi River from ExxonMobil’s refinery and chemical plant, fractionates refinery grade propylene produced by ExxonMobil into chemical grade propylene for a toll-processing fee.

The following table shows net fractionation volumes and capacity (in MBPD, on a net basis in accordance with our ownership interest) and the corresponding overall utilization rates of our propylene fractionation facilities for the last three years. Net capacity amounts have been adjusted for the timing of acquisitions.

Propylene Fractionation Facility	For Year Ended December 31, 2004	2003	2002
Mont Belvieu	51	53	51
BRPC	5	4	4
Total net volume (MBPD)	56	57	55
Net capacity	65	65	63
Utilization rate	86%	88%	87%

Petrochemical pipelines and export terminal

The following table summarizes our primary petrochemical pipeline transportation and distribution networks at March 1, 2005. Our ownership interest in each pipeline is held either directly through a consolidated subsidiary or indirectly through a company in which we have an investment accounted for under the equity method. For additional information regarding our equity method investments, please read Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Petrochemical Pipelines	Length in Miles	Our Ownership Interest
Lou-Tex Propylene	291	100.0%
Lake Charles/Bayport	87	50.0% (1)
Texas City	28	100.0%
Sabine Propylene	21	100.0%
La Porte (2)	17	50.0%
Morgan's Point (3)	13	100.0%
Total petrochemical pipelines	457	

(1) Of the 87 total miles for this pipeline, we own 50% of 82 miles and 100% of the remaining 5 miles.

(2) The La Porte pipeline is an integral component of the propylene fractionation activities of Splitter III.

(3) We acquired a 13-mile petrochemical pipeline in December 2004 as part of our Morgan's Point facility acquisition.

The following is a brief description of our primary petrochemical pipeline assets, all of which we operate with the exception of the OTC Propylene Export Facility:

Lou-Tex Propylene. The Lou-Tex Propylene pipeline consists of a 291-mile pipeline used to transport propylene from Sorrento, Louisiana to Mont Belvieu, Texas. Currently, this pipeline is used to transport chemical grade propylene for third parties from production facilities in Louisiana to customers in Texas. This system also includes storage facilities and a 28-mile NGL pipeline.

Lake Charles/Bayport. The Lake Charles/Bayport pipeline system is comprised of two pipelines: a 77-mile system used (in combination with a pipeline owned and operated by ExxonMobil) to distribute polymer grade propylene from Mont Belvieu, Texas to polypropylene plants in Lake Charles, Louisiana and Bayport, Texas; and approximately 10 miles of related polymer grade propylene pipelines located in the La Porte, Texas area.

Texas City. The Texas City pipeline connects our 50% owned La Porte pipeline to various polymer grade propylene customers. This pipeline runs 28 miles south to 9 delivery locations and ends in the Texas, City, Texas area.

Sabine Propylene. The Sabine Propylene pipeline system is a 21-mile pipeline used to transport polymer grade propylene from third-party plant facilities in Port Arthur, Texas to a connection with our Lake Charles pipeline.

La Porte. The La Porte pipeline is a 17-mile pipeline used to distribute polymer grade propylene from Mont Belvieu, Texas to La Porte, Texas. This pipeline is an integral part of our Mont Belvieu propylene fractionation activities.

Morgan's Point. The Morgan's Point pipeline is a 13-mile propylene pipeline extending from our facility at Morgan's Point, Texas to the nearby Ellington Field.

OTC Propylene Export Facility. The OTC propylene export facility is an above-ground polymer grade propylene storage and export facility located in Seabrook, Texas. This facility can load vessels of polymer grade propylene at rates up to 5,000 barrels per hour. OTC's primary competitor is an export operation owned by ChevronPhillips located on the Houston Ship Channel. OTC's operations are an integral part of our Mont Belvieu propylene fractionation business.

Petrochemical pipeline and export terminal utilization

The maximum number of barrels that our petrochemical pipelines can transport per day depends upon the operating balance achieved at a given time between various segments of the system. Because the balance is dependent upon the mix of products to be shipped and the demand levels at the various delivery points, the exact capacity of the systems cannot be stated. Utilization of our primary petrochemical pipelines is measured in terms of throughput volumes. Utilization for OTC is measured in terms of volumes loaded. The following table shows the throughput volume for each asset over the last three years (in MBPD, on a net basis in accordance with our ownership interest).

	For Year Ended December 31,		
	2004	2003	2002
Lou-Tex Propylene	28	29	25
Lake Charles/Bayport	13	13	11
Sabine Propylene	11	11	11
OTC	6	3	4
Total net volume of petrochemical pipelines	58	56	51

Butane isomerization

At March 1, 2005, 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 isomerization facilities have an average combined production capacity of 116 MBPD of isobutane. We own and operate the isomerization facilities.

Our commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into normal butane, isobutane and high purity isobutane. 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. Isobutane demand is marginally higher in the spring and summer months due to the demand for isobutane-based fuel additives in the production of motor gasoline. 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. The principal uses of isobutane are for alkylate used in the production of motor gasoline, propylene oxide and in the production of MTBE and iso-octane.

The Mont Belvieu 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. In general, our third-party customers pay us a toll processing fee based on the volume of isobutane we produce for them. Our NGL marketing activities utilize these facilities to convert normal and/or mixed butanes into isobutane in order to satisfy isobutane sales contracts. We also use our isomerization facility to meet the feedstock requirements of our octane additive production facility. The revenues and expenses we record for such intercompany transactions are eliminated in consolidation. During 2004, 49 MBPD of our isobutane production was attributable to third party agreements, with the balance of 27 MBPD related to intercompany arrangements.

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 believe that our isomerization facilities benefit from the integrated nature of our Mont Belvieu complex with its extensive connections to pipeline and storage assets.

The following table shows isobutane production and capacity and overall utilization of the Mont Belvieu facility for the last three years:

Mont Belvieu Isomerization Facility	For Year Ended December 31, 2004	2003	2002
Production (MBPD)	76	77	84
Net capacity (MBPD)	116	116	116
Utilization rate (1)	66%	66%	72%

(1) 2003 production and utilization rate decreased when compared to 2002 as a result of lower isobutane feedstock demand from BEF.

Octane enhancement

We own a 100% interest in Belvieu Environmental Fuels ("BEF"), which owns an octane additive production facility designed to produce both iso-octane and MTBE, which are motor gasoline additives that increase octane and are used in reformulated motor gasoline blends. We operate the facility, which is located within our Mont Belvieu complex. On September 30, 2003, we purchased an additional 33.3% interest in this facility, at which time BEF became a majority-owned consolidated subsidiary of ours. On September 1, 2004, we acquired the remaining 33.3% interest in BEF.

Prior to 2005, BEF primarily produced MTBE, the production of which was primarily driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990. 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 have enacted legislation to ban or significantly limit the use of MTBE in motor gasoline within their jurisdictions. In addition, federal legislation has been drafted to ban MTBE and replace the oxygenate with renewable fuels such as ethanol. Although numerous resulting legal actions have been filed against motor gasoline and MTBE producers, BEF has not been named in any MTBE legal action to date.

As a result of these developments, we are in the process of modifying the facility to also produce iso-octane, a motor gasoline octane enhancement additive derived from isobutane. We expect iso-octane 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 (including pending federal legislation) the facility may be further modified in the future to produce alkylate.

BEF produces iso-octane using feedstocks of high-purity isobutane and MTBE using both high-purity isobutane and methanol. The high-purity isobutane feedstock requirements are met using production from our Mont Belvieu isomerization units. BEF's methanol requirements for MTBE production are met through spot market purchases. We compete with other octane additive manufacturing companies primarily on the basis of price. Historically, MTBE prices have been stronger during the April to September period of each year, which corresponds with the summer driving season. We expect to experience the same seasonal demand for iso-octane. BEF's iso-octane production can be transported using our HSC Pipeline to a location on the Houston Ship Channel for delivery to customers.

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 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 a non-cash asset impairment charge of $67.5 million. Our share of this loss was $22.5 million and is recorded as a component of "Equity in income (loss) of unconsolidated affiliates" in our Statements of Consolidated Operations and Comprehensive Income for the year ended December 31, 2003.

The following table shows BEF's historical MTBE production volumes and capacity (on a net basis in accordance with our ownership interest) and the corresponding overall utilization rates of the BEF facility for the last three years. Net capacity for 2004 and 2003 has been adjusted for our September 2004 and September 2003 acquisitions of the additional 33.3% interests in the facility.

BEF Facility	For Year Ended December 31, 2004	2003	2002
Gross MTBE production capacity (MBPD)	16.5	16.5	16.5
Net MTBE production capacity (MBPD)	9.4	7.0	5.5
Net MTBE production volume (MBPD)	7.8	4.4	5.1
Utilization rate	83%	62%	94%

Intangible Assets

At December 31, 2004, the Petrochemical Services segment included $51.3 million of intangible assets primarily related to contract-based rights that we own. For information regarding our intangible assets, please read Note 8 of the Notes to Consolidated Financial Statements.

EMPLOYEES

We do not have any employees. EPCO employs most of the persons necessary for the operation of our business. At December 31, 2004, EPCO had approximately 2,345 employees involved in the management and operations of our business, none of whom were members of a union. We fully reimburse EPCO for the costs of all 2,345 employees. For a detailed discussion of our related party transactions with EPCO, please read Item 13 of this annual report. In addition to EPCO employees, we have engaged approximately 261 contract maintenance and other personnel who support our operations.

MAJOR CUSTOMERS

Our revenues are derived from a wide customer base. Our largest customer, Shell, accounted for 6.5%, 5.5% and 7.9% of consolidated revenues in 2004, 2003 and 2002, respectively.

REGULATION AND ENVIRONMENTAL MATTERS

Regulation of our interstate common carrier liquids pipelines

Our Mid-America, Seminole, Chunchula, Lou-Tex Propylene and Lou-Tex NGL pipelines and certain pipelines in which we own equity interests (Dixie, Tri-States, Wilprise and Belle Rose), along with certain pipelines of the Louisiana Pipeline System, are interstate common carrier liquids pipelines subject to regulation by the FERC under the October 1, 1977 version of the ICA.

As interstate common carriers, these liquids pipelines 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. The ICA requires us 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.

The ICA gives the FERC authority to regulate the rates we charge for service on the interstate common carrier pipelines. The ICA requires, among other things, that such rates be “just and reasonable” and nondiscriminatory. The ICA permits interested persons to challenge proposed new or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff during the term of the investigation. The FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

On October 24, 1992, Congress passed the Energy Policy Act of 1992 ("Energy Policy Act"). The Energy Policy Act deemed liquids pipeline rates that were in effect for the twelve months preceding enactment that had not been subject to complaint, protest or investigation to be just and reasonable under the ICA (i.e., "grandfathered"). The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party would have to show that it was previously contractually barred from challenging the rates, or that the economic circumstances of the liquids pipeline that were a basis for the rate or the nature of the service underlying the rate had substantially changed or that the rate was unduly discriminatory or preferential.

The Energy Policy Act required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for liquids pipelines, and to streamline procedures in liquids pipeline proceedings. The FERC responded to this mandate by issuing Order No. 561, which, among other things, adopted an indexing rate methodology for liquids pipelines. Under the regulations, which became effective January 1, 1995, liquids pipelines are able to change their rates within prescribed ceiling levels that are tied to an inflation index. Rate increases made within the ceiling levels will be subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline's filed rate, Order No. 561 requires the liquids pipeline to reduce its rate to comply with the lower ceiling. Under Order No. 561, a liquids pipeline may as a general rule utilize the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market-based rates, and settlement as alternatives to the indexing approach. While there has been some activity regarding challenge to grandfathered rates in an on-going case against SFPP, L.P. ("SFPP"), an unrelated interstate common carrier for refined products in the western United States, requirements for such a challenge remain uncertain. Portions of Enterprise-owned liquids pipelines have established rates meeting the grandfathering provisions.

We believe that the rates charged for transportation services on the 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.

On July 20, 2004, the United States Court of Appeals for the District of Columbia Circuit issued its opinion in *BP West Coast Products, LLC v. FERC*, addressing the rate of SFPP, a publicly traded limited partnership. The Court (i) upheld FERC's determination that some of SFPP's rates were grandfathered rates under the Energy Policy Act and that SFPP's shippers had not demonstrated substantially changed circumstances that would justify modification of those rates; (ii) eliminated the tax allowance in SFPP's rates because the SFPP limited partnership did not have tax liability; and (iii) remanded the issue of whether SFPP's revised cost of service without the tax allowance would qualify as a substantially changed circumstance that would justify modification of SFPP's rates. Because the court remanded the case to the FERC and because the FERC's ruling on the substantially changed circumstances issue will focus on the facts and record presented to it, it is not clear what impact, if any, the opinion will have on our rates or on the rates of other FERC-jurisdictional pipelines organized as tax pass-through entities. FERC has initiated a public inquiry in Docket No. PL05-5 into the proper treatment of income tax allowances on cost-of-service ratemaking proceeding involving partnerships. Moreover, it is not clear whether FERC's action taken in response to *BP West Coast* will be challenged and, if so, whether it will withstand further FERC or judicial review.

Parties could challenge the rates of our common carrier interstate liquids pipelines and our interstate natural gas pipelines and argue that the rationale in the BP West Coast decision regarding tax allowances should be applied. While it is possible that a party might challenge these rates, it is not possible to predict the likelihood that such a challenge would succeed at the FERC.

Regulation of our interstate and intrastate natural gas pipelines

The HIOS natural gas pipeline, certain natural gas pipelines in which we own equity interests and the Petal natural gas storage facility, including the 60-mile Petal natural gas pipeline, are regulated by the FERC under the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"). Each system operates under separate FERC-approved tariffs that establish rates, terms and conditions under which each system provides services to its customers. Pursuant to 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.

In addition, the FERC's authority over natural gas companies that provide natural gas pipeline transportation or storage services in interstate commerce includes the rates charged for the services, terms and conditions of service, 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 services, and various other matters. As noted above, our regulated natural gas pipelines and natural gas storage facility have tariffs established through FERC filings that have a variety of terms and conditions, each of which affect the operations of each system and its ability to recover fees for the services it provides. Generally, changes to these fees or terms can only be implemented upon approval by the FERC. We also own several natural gas intrastate systems that provide transportation and storage pursuant to Section 311 of the NGPA and Section 284 of the Commission's Regulations. Under Section 311 of the NGPA an intrastate pipeline company may transport gas for an interstate pipeline company or any local distribution company served by an interstate pipeline. The rates for Section 311 service can be established by the FERC or the respective state agency. The associated rates may not exceed a fair and equitable rate. FERC has exempted the construction of facilities used solely for Section 311 transportation from FERC's certificate requirements.

In addition to its jurisdiction under the Natural Gas Act and the Natural Gas Policy Act, the FERC also attempted to use the Outer Continental Shelf Lands Act ("OCSLA") open access provisions to expand its jurisdiction over pipelines on the Outer Continental Shelf . The OCSLA requires that all pipelines operating on or across the outer continental shelf provide open-access, non-discriminatory transportation service on their systems. The U.S. Court of Appeals for the District of Columbia Circuit recently upheld a lower court's rejection of FERC's attempt to implement regulations pertaining to "gas service providers" operating on the outer continental shelf. The Minerals Management Service ("MMS"), a bureau in the U.S. Department of the Interior, is the Federal agency that manages the nation's natural gas, oil and other mineral resources on the outer continental shelf ("OCS") is also reviewing its jurisdiction with respect to the open-access, non-discriminatory provisions of the OCSLA. We cannot predict what further action FERC or the MMS will take under its OCSLA authority.

In November 2003, the FERC issued final rules governing the standards of conduct between transmission providers and their energy affiliates that apply to interstate natural gas pipelines and public utilities. The rules became effective on February 9, 2004, and on or before that date, each transmission provider was required to file with the FERC a plan and schedule for implementing the new rules. The rules substantially modify the scope of the FERC's previous standards of conduct regulations by broadening the definition of "affiliates" covered by the standards of conduct to include "energy affiliates." The rules make each transmission provider responsible for ensuring complete separation of certain functions between itself and its "energy affiliates" and for compliance with specific information disclosure prohibitions. The rules require that transmission providers conduct training for all employees regarding the scope and content of the rules, and hire or designate a chief compliance officer who is responsible for employee training and answering employee questions regarding the new rules and coordinating audits and investigations with FERC staff, as well as ensuring that the transmission provider complies with the standards of conduct. The rules prohibit employees of a transmission provider from using any third party, affiliate or employee of an affiliate as a conduit for sharing information that is prohibited under the rules from disclosure to energy affiliates.

On April 16, 2004 and August 2, 2004, the FERC issued Orders on rehearing regarding certain aspects of Order No. 2004. Those rehearing orders were issued as Order No. 2004-A and 2004-B, respectively. Among other things, FERC ruled that the Final Rule was needed and extended the compliance date to September 22, 2004. On July 27, 2004, GulfTerra filed a request for temporary limited waivers of certain requirements of the Standards of Conduct. The requested waivers were necessary because of its merger with Enterprise. GulfTerra requested that the FERC grant limited waivers of compliance for those aspects of the Standards of Conduct that could not be fully addressed until after the merger was consummated. The waiver request was for a period of 45 days after the merger. The FERC granted a 30 day extension after the merger was complete to comply. October 30, 2004 was the date for compliance. On December 21, 2004, the FERC issued Order No. 2004-C which clarified certain aspects of the Order. The Company believes compliance with this Final rule should not be unduly burdensome.

Regulation of our intrastate common carrier liquids and natural gas pipelines

Our intrastate NGL and natural gas pipelines are subject to regulation in Alabama, Colorado, Kansas, Illinois, Louisiana, Mississippi, New Mexico and Texas and some of our intrastate natural gas pipelines are subject to regulation by the FERC pursuant to Section 311 of the NGPA. Certain portions of the Louisiana Pipeline System and the majority of the Acadian Gas natural gas pipeline systems are intrastate common carrier pipelines that are subject to various Louisiana state laws and regulations that affect the rates we charge and the terms of service. The Texas Intrastate System and the Alabama Intrastate System are subject to state laws and regulations in Texas and Alabama and to FERC regulation under Section 311 of the NGPA. We also have natural gas underground storage facilities in Louisiana, Mississippi and Texas that are subject to state regulations.

Intrastate movements of products on the Seminole, Mid-America, Belle Rose and certain pipelines of the Louisiana Pipeline System are provided by them as intrastate common carriers that 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 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.

Other state and local regulation of our operations

Our business activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies pursuant thereto, governing a wide variety of matters, including marketing, production, pricing, community right-to-know, protection of the environment, safety and other matters.

For additional information regarding the potential impact of federal, state or local regulatory measures on our business, please read the section titled “Risk Factors - Federal, state or local regulatory measures could materially affect our business,” included under Item 7 of this annual report.

Environmental Matters

General Regulations

We are subject to extensive federal, state and local laws and regulations governing environmental quality and pollution control. These 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 accruals accordingly. For a summary of our significant environmental-related accruals, please read Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our offshore pipelines and services 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.

Our onshore natural gas pipelines, gas processing and treating plants 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 and Community Right-to-Know Act and similar state statutes. We have ongoing programs designed to keep our natural gas pipelines and gas processing plants in compliance with environmental and safety requirements, and we believe that our facilities are in material compliance with the applicable requirements. As of December 31, 2004, we had a reserve of approximately $21 million, included in other noncurrent liabilities, for environmental remediation costs expected to be incurred over time associated with mercury meters. GulfTerra assumed this liability in connection with its April 2002 acquisition of certain El Paso assets.

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 and Community Right-to-Know Act and similar state statutes. We have ongoing programs designed to keep our NGL pipelines and NGL fractionation, NGL storage and petrochemical storage operations in compliance with environmental and safety requirements, and we believe that our facilities are in material compliance with the applicable requirements.

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. 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.

Specific Regulations

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, or 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 EPA 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 natural gas, 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, or CAA, 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 our operations will be materially adversely affected by and such requirements.

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, or 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.

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.

TITLE TO PROPERTIES

Our real property holdings fall into two basic categories: (1) parcels that we own in fee, such as the land at the Mont Belvieu complex and (2) parcels in which our interest derives 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 major 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 have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way or license held by us or to our title to any material lease, easement, right-of-way, permit or license, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way and licenses.

A significant portion of the rights-of-way underlying the San Juan gathering system on Native American lands expire in 2005. We believe we will be able to renew these rights-of-way on terms and conditions that will not be materially adverse to us.

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 aware of no significant litigation, pending or threatened, that may have a significant adverse effect on our financial position or results of operations.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

There were no matters submitted to a vote of our unitholders during the fourth quarter of 2004.

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 traded on the NYSE under the symbol "EPD." As of March 1, 2005, there were an estimated 852 unitholders of record of our common units. The following table sets forth, for the periods indicated, the high and low sales price ranges for the common units, as reported on the NYSE Composite Transaction Tape, and the amount, record date and payment date of the quarterly cash distributions paid per common unit.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2003					
1st Quarter	$ 21.000	$ 17.850	$ 0.3625	Apr. 30, 2003	May 12, 2003
2nd Quarter	$ 24.690	$ 20.620	$ 0.3625	Jul. 31, 2003	Aug. 11, 2003
3rd Quarter	$ 24.100	$ 20.250	$ 0.3725	Oct. 31, 2003	Nov. 12, 2003
4th Quarter	$ 24.980	$ 20.760	$ 0.3725	Jan. 30, 2004	Feb. 11, 2004
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. 11, 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

The quarterly cash distribution amounts shown in the table above correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., payments to our limited partners) occur within 45 days after the end of such quarter. Although the payment of cash dividends is not guaranteed, we expect to continue to pay comparable cash distributions in the future. We agreed in the merger agreement with GulfTerra, subject to the terms of our partnership agreement, to increase the quarterly cash distribution for the quarterly distribution date immediately following the closing of the merger to at least $0.395 per unit, or $1.58 per common unit on an annualized basis. The increase in our quarterly cash distribution commenced with the distribution paid with respect to the third quarter of 2004. On January 19, 2005, we announced that our quarterly cash distribution with respect to the fourth quarter of 2004 was raised to $0.40 per unit, or $1.60 per common unit on an annualized basis.

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 "*Our Liquidity and Capital Resources*" included under Item 7 of this annual report.

Recent sales of unregistered securities. There were no unreported sales of unregistered equity securities during 2004. On December 17, 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO, for $100 million in a private transaction that was exempt from the registration requirements of the Securities Act of 1933, pursuant to Section 4(2) thereof. On July 29, 2004, we requested that our common unitholders approve the conversion of all of the non-voting Class B special units into voting common units on a one-for-one basis at a special meeting that was held on July 29, 2004, to approve our merger with GulfTerra. On this date, our common unitholders approved the conversion and our 4,413,549 Class B special units converted to an equal number of common units.

Common Units Authorized for Issuance Under Equity Compensation Plan. Please read the information included under Item 12 of this annual report, regarding securities authorized for issuance under equity compensation plans, which information is incorporated by reference into this Item 5.

Repurchases of Common Units. We did not repurchase any of our common units during 2004. Previously, on December 23, 1998, we announced a common units 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 two-for-one unit split in May 2002). As of March 1, 2005, we and our affiliates are authorized to repurchase up to 618,400 additional common units under this repurchase program. Common units repurchased under this program are classified as treasury units.

ITEM 6. SELECTED FINANCIAL DATA.

The following table sets forth for the periods and at the dates indicated, our selected historical financial data. The selected historical financial data as of and for each of the five years in the period ended December 31, 2004 have been derived from the audited financial statements for the periods indicated. This information should be read in conjunction with our audited financial statements for such periods included under Item 8 of this annual report. In addition, information regarding our results of operations and capital resources and liquidity can be found under Item 7 of this annual report, "*Management's Discussion and Analysis of Financial Condition and Results of Operations*." As presented in the table below, dollar amounts (except earnings per unit data) and total units outstanding are in thousands.

	Year Ended December 31,				
	2004	2003	2002	2001	2000
Operating results data: (1)					
Revenues	$ 8,321,202	$ 5,346,431	$ 3,584,783	$ 3,154,369	$ 3,049,020
Income from continuing operations	$ 257,480	$ 104,546	$ 95,500	$ 242,178	$ 220,506
Income from continuing operations: (2,3)					
Basic	$ 0.83	$ 0.42	$ 0.55	$ 1.70	1.62
Diluted	$ 0.83	$ 0.41	$ 0.48	$ 1.39	1.32
Other financial data:					
Distributions per common unit (6)	$ 1.540	$ 1.470	$ 1.360	$ 1.194	$ 1.050
Commodity hedging income (loss)(7)	$ 448	$ (619)	$ (51,344)	$ 101,290	$ 26,743

	As of December 31,				
	2004	2003	2002	2001	2000
Financial position data: (1)					
Total assets	$ 11,315,461	$ 4,802,814	$ 4,230,272	$ 2,424,692	$ 1,951,368
Long-term and current maturities of debt (4)	$ 4,281,236	$ 2,139,548	$ 2,246,463	$ 855,278	$ 403,847
Partners' equity (5)	$ 5,328,785	$ 1,705,953	$ 1,200,904	$ 1,146,922	$ 935,959
Total units outstanding (excluding treasury)(3)	364,786	217,780	183,810	174,542	168,868

The following information is provided to highlight significant trends and other information regarding our historical operating results, financial position and other financial data. Each section below represents a footnote to the preceding table.

(1) In general, our historical operating results and/or financial position have been affected by numerous acquisitions since 2000. 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 4 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

(2) Basic earnings per unit is calculated using the weighted-average number of common, subordinated, restricted and Class B special units that were outstanding during each period. Diluted earnings per unit is

calculated using the weighted-average number of common, subordinated, restricted, performance-based restricted and Class A and B special units outstanding during each period.

(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) 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 the acquisitions.

(5) We regularly issue common units in public offerings and may also issue other types of limited partner interests in connection with acquisitions or other transactions that increase partners' equity. The increase in partners' equity since 2000 has been the result of such transactions, with the issuance of 104.5 million in common units valued at $2.4 billion on September 30, 2004 in connection with the GulfTerra Merger being our largest. For additional information regarding our partners' equity and unit history, please read Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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

(7) Income from continuing operations includes our results from commodity hedging activities. In order to manage the risks associated with our natural gas processing business and related NGL marketing activities, we may enter into various commodity financial instruments. The primary purpose of these risk management activities is to hedge our exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and anticipated transactions. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes. 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 loss. 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 Note 18 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.

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership listed on the NYSE symbol "EPD". Unless the context requires otherwise, references to "we," "us," "our," "the Company" or "Enterprise" are intended to mean the consolidated business and operations of Enterprise Products Partners L.P. Certain abbreviated names and other capitalized and industry terms are defined within the glossary of this annual report on Form 10-K.

We were formed in April 1998 to own and operate certain NGL related businesses of EPCO, Inc. ("EPCO," formerly Enterprise Products Company). 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 GP"). We and Enterprise GP are affiliates of EPCO.

The following discussion and analysis should be read in conjunction with our audited consolidated financial statements and notes included under Item 8 of this annual report. In addition, the reader should review "*Cautionary Statement Regarding Forward-Looking Information*" under Item 1 of this annual report for information regarding forward-looking statements made in this discussion. The reader should also review the section titled "*Risk Factors*" included within this Item 7 discussion for information regarding certain risks inherent in our business. Other risks involved in our business are discussed under "*Quantitative and Qualitative Disclosures about Market Risk*" included under Item 7A of this annual report. Additionally, please see Part III, Item 13 for a discussion of related-party matters.

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RECENT DEVELOPMENTS

GulfTerra Merger. On September 30, 2004, Enterprise and GulfTerra completed the merger of GulfTerra with a wholly owned subsidiary of Enterprise, with GulfTerra being the surviving entity thereof. Additionally, Enterprise completed certain other transactions related to the merger, including receipt of Enterprise GP's contribution of a 50% membership interest in GulfTerra GP, which was acquired by Enterprise GP from El Paso, and the purchase of certain midstream energy assets located in South Texas from El Paso. The aggregate value of the total consideration Enterprise paid or issued to complete the GulfTerra Merger was approximately $4 billion.

As a result of the GulfTerra Merger, GulfTerra and GulfTerra GP became wholly owned subsidiaries of Enterprise on September 30, 2004. On October 1, 2004, we contributed our ownership interests in GulfTerra and GulfTerra GP to our Operating Partnership, which resulted in GulfTerra and GulfTerra GP becoming wholly owned subsidiaries of the Operating Partnership.

Formed in 1993, GulfTerra manages a balanced, diversified portfolio of interests and assets relating to the midstream energy sector, which involves gathering, transporting, separating, processing, fractionating and storing natural gas, oil and NGLs. GulfTerra's interests and assets included (i) offshore oil and natural gas pipelines, platforms, processing facilities and other energy infrastructure in the Gulf of Mexico, primarily offshore Louisiana and Texas; (ii) onshore natural gas pipelines and processing facilities in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas; (iii) onshore NGL pipelines and fractionation facilities in Texas; and (iv) onshore natural gas and NGL storage facilities in Louisiana, Mississippi and Texas.

The South Texas midstream assets consisted of nine natural gas processing plants with a combined capacity of 1.9 Bcf/d, a 294-mile natural gas gathering system, a natural gas treating facility with a capacity of 150 MMcf/d and a small NGL pipeline.

The GulfTerra Merger transactions

The GulfTerra Merger occurred in several interrelated transactions as described below.

- *Step One*. On December 15, 2003, Enterprise purchased a 50% membership interest in GulfTerra GP from El Paso for $425 million in cash. GulfTerra GP owns a 1% general partner interest in GulfTerra. Prior to completion of the GulfTerra Merger, Enterprise accounted for its investment in GulfTerra GP using the equity method of accounting. The $425 million in funds required to complete Step One were borrowed under an Interim Term Loan and our pre-merger revolving credit facilities. This amount was fully repaid with the net proceeds from equity offerings completed during 2004. For additional information regarding changes in our debt obligations since December 31, 2003, please see Note 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

- *Step Two*. On September 30, 2004, the GulfTerra Merger was consummated and GulfTerra and GulfTerra GP became wholly owned subsidiaries of Enterprise. 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 GP acquired El Paso's remaining 50% membership interest in GulfTerra GP for $370 million in cash paid to El Paso and the issuance of a 9.9% membership interest in Enterprise GP to El Paso. Subsequently, Enterprise 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 GP borrowed the foregoing $370 million from Dan Duncan LLC (which owns a membership interest in Enterprise GP), which obtained the funds from a loan from EPCO (which indirectly owns the remaining membership interests in Enterprise GP).

  - Immediately prior to closing the GulfTerra Merger, Enterprise 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 (7,433,425 of which were owned by El Paso) were converted into

104,549,823 Enterprise common units (13,454,499 of which are held by El Paso) at the time of the consummation of the GulfTerra Merger.

- *Step Three*. Immediately after Step Two was completed, Enterprise acquired certain South Texas midstream assets from El Paso for $155.3 million in cash. Pursuant to written agreements, our purchase of the South Texas midstream assets was effective September 1, 2004.

In connection with the closing of the GulfTerra Merger, on September 30, 2004, our Operating Partnership borrowed an aggregate $2.8 billion under its new revolving credit facilities to fund its cash payment obligations under Step Two and Step Three of the GulfTerra Merger and related transactions, including the tender offers for GulfTerra's outstanding senior and senior subordinated notes.

In connection with the GulfTerra Merger, we are required under a consent decree to sell our 50% interest in Starfish, which owns the Stingray natural gas pipeline and related gathering pipelines and dehydration and other facilities located in south Louisiana and the Gulf of Mexico offshore Louisiana by March 31, 2005. In January 2005, we entered into a contract with a third party to sell this investment for approximately $41.2 million. We expect to close this sale during the first quarter of 2005. The sale requires FTC approval under the terms of the consent decree relating to the GulfTerra Merger and is subject to other customary closing conditions. Additionally, under the same consent decree, we were required to sell our undivided 50% interest in a Mississippi propane storage facility by December 31, 2004. We sold our interest in this facility during the fourth quarter of 2004.

For additional information regarding the GulfTerra Merger and our other business combinations and asset acquisitions completed during 2004 (including selected pro forma financial information), please read Note 4 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Acquisition of El Paso's Interests in Enterprise and Enterprise GP by affiliates of EPCO. In January 2005, affiliates of EPCO acquired a 9.9% membership interest in Enterprise GP and 13,454,499 Enterprise common units from El Paso for approximately $425 million in cash. As a result of these transactions, EPCO and its affiliates own 100% of the membership interests of Enterprise GP and approximately 37.4% of our total outstanding common units. El Paso no longer owns any interest in us or Enterprise GP.

Agreement with Atwater Valley Producers Group for Deepwater Platform and Gas Pipeline. In November 2004, we entered into an agreement with the Atwater Valley Producers Group (consisting of Anadarko, Dominion, Kerr-McGee, Spinnaker and Devon) for the dedication, processing and gathering of natural gas and condensate production from several natural gas fields in the Atwater Valley, DeSoto Canyon and Lloyd Ridge areas of the deepwater Gulf of Mexico. We will design, construct, install and own Independence Hub, a 105-foot deep-draft, semi submersible platform with a two-level production deck, which will be capable of processing 850 MMcf/d of natural gas. The platform, which is estimated to cost approximately $385 million, will be operated by Anadarko. Cal Dive is our 20% joint venture partner in the Independence Hub Platform project. Additionally, we will construct, own, and operate the 134-mile Independence Trail natural gas pipeline system, which will have a throughput capacity of approximately 850 MMcf/d of natural gas. The pipeline system, which is estimated to cost $280 million, will transport production from the Independence Hub platform to the Tennessee Gas Pipeline.

Rocky Mountain NGL pipeline expansion and related NGL fractionation projects. In January 2005, we started a project to expand our Mont Belvieu NGL fractionator to accommodate increased production of NGLs being transported to Mont Belvieu from the Rocky Mountain area. Our Mont Belvieu facility's current fractionation capacity is up to 210 MBPD of mixed NGLs. This project, which is expected to be completed in the first quarter of 2006 at an estimated total cost of $34.2 million, will increase total fractionation capacity at this facility by 15 MBPD and reduce its energy costs. Additionally, we are reviewing a proposal to construct a new NGL fractionator at our Mont Belvieu complex that could add an additional 60 MBPD of fractionation capacity at this industry hub.

Currently, the Rocky Mountain segment of our Mid-America pipeline system transports up to 225 MBPD of NGLs from the major producing basins in Wyoming, Utah, Colorado and New Mexico to the Hobbs station on the Texas-New Mexico border. The Western Expansion Project would increase the capacity of this pipeline to 275 MBPD. Permitting, engineering and design work are in progress. We submitted a draft environmental assessment and plan of development to the appropriate regulatory agencies during the first quarter of 2005. Contingent upon receiving all required permits and regulatory approvals, construction could begin as early as the fourth quarter of 2005.

Acquisition of Indian Springs natural gas gathering and processing assets from El Paso. In January 2005, we paid El Paso $74.5 million for their membership interests in Teco Gas Gathering, LLC and Teco Gas Processing, LLC. As a result of this acquisition, we indirectly own an 80% equity interest in the 89-mile Indian Springs Gathering System and a 75% equity interest in the Indian Springs natural gas processing facility, both of which are located in East Texas. The Indian Springs processing facility has capacity to process up to 120 MMcf/d of natural gas and there is an idle 20 MMcf/d production train available for restart to support increases in natural gas volumes. The natural gas processed at the Indian Springs processing facility is sourced from the Indian Springs Gathering System, as well as our nearby Big Thicket Gathering System.

*February 2005 equity offering***.** In February 2005, we sold 17,250,000 common units (including the over-allotment amount of 2,250,000 common units which closed on March 11, 2005) to the public at an offering price of $27.05 per unit. Net proceeds from this offering, including Enterprise GP's proportionate net capital contribution of $9.1 million, were approximately $456.5 million after deducting applicable underwriting discounts, commissions and estimated offering expenses of $19.7 million. The net proceeds from this offering, including Enterprise GP's proportionate net capital contribution, were used to repay our 364-Day Acquisition Credit Facility, to temporarily reduce indebtedness outstanding under our Multi-Year Revolving Credit Facility or for general partnership purposes.

Acquisition of Additional Interests in Dixie Pipeline Company. We purchased an approximate 26% interest in Dixie from an affiliate of ChevronTexaco in February, 2005 for $40 million, and an approximate 20% interest in Dixie from an affiliate of ConocoPhillips in January, 2005 for $31 million. As a result of these acquisitions, our ownership interest in Dixie is now approximately 66% and will be a consolidated subsidiary. The other owners of Dixie are affiliates of BP with a 23% interest and ExxonMobil with an 11% interest. Dixie owns and operates the 1,301-mile Dixie Pipeline, which is a pipeline that transports propane from supply areas in Texas, Louisiana and Mississippi to markets throughout the southeastern United States. The Dixie Pipeline is regulated by the FERC and transports an average of approximately 100 MBPD per day of propane.

March 2005 private senior notes offering. On February 15, 2005, our Operating Partnership sold $500 million in principal amount of senior notes in a private offering, comprised of $250 million in principal amount of 10-year senior unsecured notes and $250 million in principal amount of 30-year senior unsecured notes. The 10-year notes ("Senior Notes I") were issued at 99.379% of their principal amount and have fixed-rate interest of 5.00% and a maturity date of March 1, 2015. The 30-year notes ("Senior Notes J") were issued at 98.691% of their principal amount and have fixed-rate interest of 5.75% and a maturity date of March 1, 2035. The Operating Partnership used the net proceeds from the issuance of Senior Notes I and J to repay $350 million of indebtedness outstanding under Senior Notes A which was due on March 15, 2005 and the remaining proceeds for general partnership purposes, including the temporary repayment of indebtedness outstanding under the Multi-Year Revolving Credit Facility. This transaction closed on March 2, 2005. For additional information regarding our debt obligations, please read "*Liquidity and Capital Resources — Our Debt Obligations*" included within this Item 7 discussion and Note 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

*March 2005 $4 Billion Universal Shelf Registration Filing***.** On March 3, 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of partnership equity and public debt obligations. In connection with this registration statement, we also registered for resale 36,572,122 common units currently owned by Shell and 4,427,878 common units that had been sold by Shell to Kayne Anderson MLP Investment Company in December 2004. We are obligated to register the resale of these common units under a registration rights agreement we executed with Shell in connection with our acquisition of certain of Shell's Gulf Coast midstream energy businesses in September 1999. For additional information regarding our equity and debt offerings, please read "*Our Liquidity and Capital Resources*" included within this Item 7 discussion.

OUR RESULTS OF OPERATIONS

As a result of completing the GulfTerra Merger on September 30, 2004, our Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2004 includes three months of results of operations from the GulfTerra assets. The effective closing date of our purchase of the South Texas midstream assets was September 1, 2004; thus, our Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2004 includes four months of results of operations from the South Texas midstream assets.

As a result of the GulfTerra Merger, we have reorganized our reportable business segments, as described below. We have also revised our prior segment information in order to conform to the current business segment operations and presentation.

We have segregated our business activities into four reportable business segments: Offshore Pipelines & Services, Onshore Natural Gas Pipelines & Services, NGL Pipelines & Services, and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered and products produced and/or sold. For a listing of the major components of each of our four new business segments, and the principal operating assets included within each of the major components, please read Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The Offshore Pipelines & Services business segment consists of (i) approximately 1,150 miles of offshore natural gas pipelines strategically located to serve production areas in some of the most active drilling and development regions in the Gulf of Mexico, (ii) approximately 800 miles of Gulf of Mexico offshore crude oil pipeline systems and (iii) seven multi-purpose offshore hub platforms located in the Gulf of Mexico, which are included in our Offshore Pipelines & Services business segment.

The Onshore Natural Gas Pipelines & Services business segment consists of 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, this segment includes two salt dome natural gas storage facilities located in Mississippi, which are strategically located to serve the Northeast, Mid-Atlantic and Southeast domestic natural gas markets. This segment also includes leased natural gas storage facilities located in Texas and Louisiana.

The NGL Pipelines & Services business segment includes our (i) natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating approximately 12,775 miles and related storage facilities, which include our strategic Mid-America and Seminole NGL pipeline systems and (iii) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our import and export terminaling operations.

The Petrochemical Services business segment includes four propylene fractionation facilities, an isomerization complex, and an octane additive production facility. This segment also includes various petrochemical pipeline systems.

The Other non-segment category is presented for financial reporting purposes only to reflect the historical equity earnings we received from GulfTerra GP and our underlying investment in this entity at December 31, 2003. We acquired a 50% membership interest in GulfTerra GP on December 15, 2003 in connection with Step One of the GulfTerra Merger. Our 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.

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: (1) depreciation, depletion and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, 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 intercompany 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 through our investments in Poseidon, Cameron Highway, Deepwater Gateway, Neptune and Nemo. We also have a number of investments in NGL transportation or distribution pipelines such as those owned by Belle Rose and Dixie (prior to our purchasing consolidating interests in Dixie in January and February 2005). 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 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. For additional information regarding our business segments, please read Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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

	Year Ended December 31,		
	2004	2003	2002
Gross operating margin by segment:			
Onshore Natural Gas Pipelines & Services	$ 90,977	$ 18,345	$ 22,110
NGL Pipelines & Services	374,196	310,677	181,928
Petrochemical Services	121,515	75,885	117,776
Offshore Pipeline & Services	36,478	5,561	10,535
Other, non-segment	32,025	(53)	—
Total segment gross operating margin	$ 655,191	$ 410,415	$ 332,349

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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 the cumulative effect of changes in accounting principles, please read "*Other Items*" included within this Item 7 discussion on page 80 of this annual report.

Selected Price and Volumetric Information

The following table illustrates selected average quarterly industry index prices for natural gas, crude oil, selected NGL and petrochemical products and indicative gas processing gross spreads since the beginning of 2002:

	Natural Gas, $/MMBtu (1)	Crude Oil, $/barrel (2)	Ethane, $/gallon (1)	Propane, $/gallon (1)	Normal Butane, $/gallon (1)	Isobutane, $/gallon (1)	Natural Gasoline, $/gallon (1)	Polymer Grade Propylene, $/pound (1)	Refinery Grade Propylene, $/pound (1)	Indicative Gas Processing Gross Spread, $/gallon (3)
2002										
1st Quarter	$ 2.34	$ 21.41	$ 0.22	$ 0.30	$ 0.38	$ 0.44	$ 0.47	$ 0.16	$ 0.12	$ 0.12
2nd Quarter	$ 3.38	$ 26.26	$ 0.26	$ 0.40	$ 0.48	$ 0.51	$ 0.58	$ 0.20	$ 0.17	$ 0.10
3rd Quarter	$ 3.16	$ 28.30	$ 0.26	$ 0.42	$ 0.52	$ 0.58	$ 0.61	$ 0.21	$ 0.16	$ 0.14
4th Quarter	$ 3.99	$ 28.33	$ 0.31	$ 0.49	$ 0.60	$ 0.63	$ 0.66	$ 0.20	$ 0.15	$ 0.13
Average for Year	$ 3.22	$ 26.08	$ 0.26	$ 0.40	$ 0.50	$ 0.54	$ 0.58	$ 0.20	$ 0.15	$ 0.12
2003										
1st Quarter	$ 6.58	$ 34.12	$ 0.43	$ 0.65	$ 0.76	$ 0.80	$ 0.85	$ 0.24	$ 0.21	$ 0.05
2nd Quarter	$ 5.40	$ 29.04	$ 0.39	$ 0.53	$ 0.58	$ 0.62	$ 0.65	$ 0.25	$ 0.19	$ 0.04
3rd Quarter	$ 4.97	$ 30.21	$ 0.37	$ 0.56	$ 0.67	$ 0.68	$ 0.73	$ 0.21	$ 0.15	$ 0.10
4th Quarter	$ 4.58	$ 31.18	$ 0.40	$ 0.58	$ 0.73	$ 0.71	$ 0.75	$ 0.22	$ 0.16	$ 0.17
Average for Year	$ 5.38	$ 31.14	$ 0.40	$ 0.58	$ 0.68	$ 0.70	$ 0.74	$ 0.23	$ 0.18	$ 0.09
2004										
1st Quarter	$ 5.69	$ 35.25	$ 0.43	$ 0.66	$ 0.76	$ 0.76	$ 0.87	$ 0.29	$ 0.26	$ 0.13
2nd Quarter	$ 6.00	$ 38.34	$ 0.45	$ 0.65	$ 0.79	$ 0.79	$ 0.92	$ 0.32	$ 0.26	$ 0.12
3rd Quarter	$ 5.75	$ 43.90	$ 0.52	$ 0.79	$ 0.92	$ 0.92	$ 1.05	$ 0.32	$ 0.27	$ 0.26
4th Quarter	$ 7.07	$ 48.31	$ 0.60	$ 0.85	$ 1.03	$ 1.04	$ 1.15	$ 0.40	$ 0.35	$ 0.22
Average for Year	$ 6.13	$ 41.45	$ 0.50	$ 0.74	$ 0.88	$ 0.88	$ 1.00	$ 0.33	$ 0.29	$ 0.18

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including OPIS and 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.

(3) The Indicative Gas Processing Gross Spread is a relative measure used by the NGL industry as an indicator of the gross economic benefit derived from extracting NGLs from natural gas production on the U.S. Gulf Coast. Specifically, it is the amount by which the economic value of a composite gallon of NGLs exceeds the value of the equivalent amount of energy of natural gas based on NGL and natural gas prices on the U.S. Gulf Coast. It is assumed that a gallon of NGLs is comprised of 33% ethane, 32% propane, 11% normal butane, 8% isobutane and 16% natural gasoline. The value of a composite gallon of NGLs is determined by multiplying these component percentages by industry index prices listed in the table above. The value of the equivalent amount of energy of natural gas to one gallon of NGLs is 8.9% of the price of a MMBtu of natural gas. The Indicative Gas Processing Gross Spread does not consider the operating and fuel costs incurred by a natural gas processing plant to extract the NGLs nor the transportation and fractionation costs to deliver the NGLs and natural gas to market.

Our significant throughput, production and processing volumetric data were as follows for the periods indicated (on a net basis, taking into account our ownership interests):

	For Year Ended December 31,		
	2004 (1)	2003(1)	2002(1)
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d) (2)	2,081	433	500
Crude oil transportation volumes (MBPD)	138		
Platform gas treating (BBtus/d)	306		
Platform oil treating (MBPD)	14		
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	5,638	600	701
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	1,411	1,275	1,306
NGL fractionation volumes (MBPD)	307	227	235
Equity NGL production (MBPD)	129	43	73
Fee-based natural gas processing (MMcf/d)	1,692	194	
Petrochemical Services, net:			
Butane isomerization volumes (MBPD)	76	77	84
Propylene fractionation volumes (MBPD)	56	57	55
Octane additive production volumes (MBPD)	10	4	5
Petrochemical transportation volumes (MBPD)	71	68	46
Total, net:			
NGL, crude oil and petrochemical transportation volumes (MBPD)	1,620	1,343	1,352
Natural gas transportation volumes (BBtus/d)	7,719	1,033	1,201
Equivalent transportation volumes (MBPD)(3)	3,651	1,615	1,668

(1) Volumetric data shown above reflects net operating rates of the underlying assets for the periods in which we owned them.

(2) Excludes fourth quarter of 2004 volumes for Starfish, which we are prohibited from obtaining under an FTC consent decree published for comment on September 30, 2004.

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

The following table summarizes our consolidated revenues, costs and expenses, equity in income (loss) of unconsolidated affiliates and operating income for the periods indicated:

	For the Year Ended December 31,		
	2004	2003	2002
Revenues	$ 8,321,202	$ 5,346,431	$ 3,584,783
Operating costs and expenses	7,904,336	5,046,777	3,382,839
Selling, general and administrative costs	46,659	37,590	42,890
Equity in income (loss) of unconsolidated affiliates	52,787	(13,960)	35,253
Operating income	422,994	248,104	194,307
Interest expense	155,740	140,806	101,580
Net income	268,261	104,546	95,500

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

Revenues for 2004 increased $3.0 billion over those recorded during 2003. The increase in revenues is primarily due to (i) higher revenues from our NGL and petrochemical marketing activities due to increased sales volumes and prices and (ii) the addition of revenues from businesses acquired or consolidated during 2004, including GulfTerra, the South Texas midstream assets and BEF.

Costs and expenses increased $2.9 billion period-to-period primarily due to (i) an increase in volumes purchased including the effects of higher product prices which resulted in an increase in the cost of sales of our NGL and petrochemical marketing activities and (ii) the addition of costs and expenses attributable to assets acquired or consolidated during 2004. These increases in costs and expenses were partially offset by a gain on sale of assets of approximately $15.1 million related to the satisfaction of certain contractual requirements of a joint venture participation agreement whereby a 50% interest in Cameron Highway was sold. Approximately $10.1 million of this gain was the non-cash recognition of a long-term receivable that is due no later than December 31, 2006 while $5.0 million of the gain was associated with a contractually required cash payment received during the fourth quarter of 2004.

Our equity in earnings of unconsolidated affiliates increased $66.7 million period-to-period. The equity earnings we recorded for 2003 were impacted by a $22.5 million non-cash asset impairment charge associated with our octane enhancement business, BEF. The 2004 period includes $32 million of equity earnings from GulfTerra GP, which we began consolidating on September 30, 2004, as a result of completing the GulfTerra Merger. Additionally, 2004 includes the addition of equity earnings from investments acquired or consolidated during 2004, including VESCO and the investments we acquired in the GulfTerra Merger.

As a result of items noted in the previous paragraphs, operating income for 2004 increased $174.9 million from that recorded during 2003. Total segment gross operating margin increased $244.8 million year-to-year due to the same general reasons underlying the increase in operating income. Operating income includes costs such as depreciation and amortization and selling, general and administrative expenses that are excluded from the non-GAAP financial measure of total segment gross operating margin.

Net income increased $163.8 million to $268.3 million for 2004 compared to $104.5 million for 2003. Net income for 2004 included a $14.9 million increase in interest expense due to acquisition-related borrowings offset by a $10.8 million benefit associated with the cumulative effect of changes in accounting principles adopted during 2004. For additional information regarding the cumulative effect of changes in accounting principles we recorded during 2004, please read "*Other Items*" included within this Item 7 discussion.

The following information highlights the significant year-to-year variances in gross operating margin by business segment; selling, general and administrative costs; and interest expense:

Onshore Natural Gas Pipelines & Services. Gross operating margin for our Onshore Natural Gas Pipelines & Services segment was $91 million for 2004 compared to $18.3 million for 2003. The majority of the $72.7 million increase in gross operating margin for this segment is attributable to assets acquired in the GulfTerra Merger, including various onshore natural gas pipelines and the Petal and Hattiesburg natural gas storage facilities. Additionally, gross operating margin for our Acadian gas pipeline system increased $6.8 million period-to-period due to higher natural gas transportation volumes and natural gas sales margins during 2004. The natural gas throughput volumes on our Acadian system were 595 BBtus/d for 2004 compared to 550 BBtus/d for 2003.

NGL Pipelines & Services. Gross operating margin from NGL Pipelines & Services segment was $374.2 million for 2004 compared to $310.7 million for 2003. Gross operating margin for natural gas processing increased $81.4 million period-to-period due to improved processing economics in 2004; the addition of gross operating margin attributable to assets acquired in the GulfTerra Merger, including the Chaco, Indian Basin and South Texas natural gas processing facilities; both partially offset by lower results from our NGL marketing activities in 2004. Indicative gas processing gross spreads on the U.S. Gulf Coast averaged 18 CPG during 2004 compared to 9 CPG in 2003, which resulted in an increase in the amount of NGLs extracted. Equity NGL production was 129 MBPD for 2004 versus 43 MBPD in 2003. Natural gas processing volumes under contracts with fee-based components increased to 1,692 MMcf/d for 2004 from 194 MMcf/d in 2003 reflecting amendments to our natural gas processing contract mix.

Gross operating margin from NGL pipelines and storage services decreased $24.7 million period-to-period due to (i) a $4 million non-cash asset impairment charge we recognized in 2004 on an NGL storage facility; (ii) increased expenses associated with our pipeline integrity inspection program; and (iii) lower gross operating margin from our Lou-Tex NGL pipeline resulting from a 17 MBPD decrease in volumes due to our election to maximize total gross operating margin by diverting mixed NGLs and refinery-grade propylene to our other facilities. Partially offsetting these decreases, was improved gross operating margin from our Mid-America and Seminole pipelines resulting from a 10% increase in throughput volumes. Overall, net NGL transportation volumes were 1,411 MBPD for 2004 compared to 1,275 MBPD in 2003.

Gross operating margin from NGL fractionation increased $6.8 million period-to-period. NGL fractionation volumes were 307 MBPD in 2004 compared to 227 MBPD in 2003. Gross operating margin from our Norco facility increased by $16.5 million primarily due to (i) a 16 MBPD increase in volumes resulting from an expansion completed in the fourth quarter of 2003 and (ii) the effect of higher prices on and an increase in NGL volumes sold by Norco that it earns ownership of through percent-of-liquids based fractionation contracts. Additionally, an increase in gross operating margin of $5.8 million is attributable to the South Texas fractionators which we acquired in the GulfTerra Merger. These increases were partially offset by a $14 million decrease in gross operating margin period-to-period from our Mont Belvieu NGL fractionator primarily attributable to the timing of gains and losses associated with the measurement of NGLs in storage pending fractionation and increased operating costs due to higher natural gas prices.

Petrochemical Services. Gross operating margin from our Petrochemical Services segment was $121.5 million in 2004 compared to $75.9 million in 2003. Gross operating margin from octane enhancement increased $34.4 million period-to-period primarily due to (i) a non-cash asset impairment charge of $22.5 million recorded in 2003 related to our investment in BEF and (ii) consolidating the results of BEF after our acquisition of the remaining 33.3% ownership interest during the third quarter of 2004. Gross operating margin from propylene fractionation increased $10.1 million period-to-period primarily due to higher petrochemical marketing sales volumes, which benefited from the effects of higher polymer grade propylene prices in 2004.

Offshore Pipelines & Services. Gross operating margin for our Offshore Pipelines & Services segment was $36.5 million for 2004 compared to $5.6 million for 2003. The $30.9 million increase in this segment is primarily attributable to assets acquired in the GulfTerra Merger, including various offshore oil and natural gas pipelines and offshore platforms. Partially offsetting this increase in gross operating margin is decreased equity earnings from our Neptune natural gas pipeline investment resulting from a decrease in volumes from the Brutus and Hickory fields and natural depletion of other production fields served by this system.

Selling, general and administrative costs. Selling, general and administrative costs were $46.7 million for 2004 compared to $37.6 million during 2003. The $9.1 million increase is primarily attributable to assets acquired or consolidated during 2004.

Interest expense. Interest expense increased to $155.7 million during 2004 from $140.8 million in 2003. The $14.9 million increase is primarily due to additional debt we incurred as a result of the GulfTerra Merger, partially offset by reduced loan cost amortization primarily related to our repayment during 2003 of the $1.2 billion senior unsecured 364-Day Term Loan which we used to fund the acquisition of our interests in the Mid-America and Seminole pipelines. Our weighted-average debt principal outstanding was $2.8 billion during 2004 compared to $2.0 billion during 2003. For additional information regarding our debt obligations and changes in our debt obligations since December 31, 2003, please read "*Our Liquidity and Capital Resources — Our debt obligations*," included within this Item 7.

Comparison of Year ended December 31, 2003 with Year Ended December 31, 2002

Revenues for 2003 increased $1.8 billion over those recorded during 2002. Likewise, costs and expenses increased $1.7 billion over those of 2002. The increase in revenues and costs and expenses is primarily due to higher product sales and purchase prices and the financial results of business acquisitions, both of which offset the effect of lower volumes at some of our pipelines and facilities. In addition, costs and expenses for 2002 includes a $51.3 million loss related to commodity hedging activities.

In general, higher market prices result in increased revenues from our various marketing activities; however, these same higher prices also increase our cost of sales within these activities as feedstock and other purchase prices rise. In addition, higher natural gas market prices during 2003 increased energy-related costs for many of our businesses versus the same period in 2002. The weighted-average market price of NGLs was 57 CPG during 2003 versus 41 CPG during 2002. The market price of natural gas averaged $5.38 per MMBtu during 2003 versus $3.22 per MMBtu during 2002.

When compared to 2002, volumes at some of our downstream pipelines and facilities were lower due to a combination of (i) decreased demand for NGLs, principally ethane, by the ethylene segment of the petrochemical industry (the "ethylene industry") and (ii) lower NGL extraction rates at domestic gas processing facilities. The most significant determinant of the relative economic value of NGLs is demand by the ethylene industry for use in manufacturing plastics and chemicals. During 2003, this industry operated at lower utilization rates when compared to 2002 primarily due to a recession in the domestic manufacturing sector. Also during 2003, as a result of the higher relative cost of NGLs to crude-based alternatives such as naphtha, the ethylene industry utilized crude-based feedstock alternatives in greater quantities than during 2002. The resulting weaker demand for NGLs by this industry limited the ability of NGL producers to sell at higher product prices, which in turn resulted in decreased NGL extraction rates during 2003.

Equity earnings from unconsolidated affiliates decreased $49.2 million year-to-year primarily due to a $36.4 million decrease in equity earnings from BEF. The $36.4 million decrease in equity earnings from BEF is primarily due to a $22.5 million asset impairment charge we recorded during the third quarter of 2003; increased facility downtime during 2003 for maintenance and economic reasons; and an overall decrease in MTBE sales margins. In addition to lower earnings from BEF, approximately $4.8 million of the overall decrease in equity earnings is due to a rate case settlement recorded by Starfish in 2002.

As a result of items noted in the previous paragraphs, operating income for 2003 increased $53.8 million from that posted during 2002. Total segment gross operating margin increased $78.1 million year-to-year due to the same general reasons underlying the increase in operating income. Operating income includes costs such as depreciation and amortization and selling, general and administrative expenses that are excluded from the non-GAAP financial measure of total segment gross operating margin.

Net income increased $9 million to $104.5 million for 2003 compared to $95.5 million for 2002. Net income for 2003 reflected the $53.8 million increase in operating income discussed in the previous paragraph offset by a $39.2 million increase in interest expense due to acquisition-related borrowings.

The following information highlights the significant year-to-year variances in gross operating margin by business segment; selling, general and administrative costs; and interest expense:

Onshore Natural Gas Pipelines & Services. Gross operating margin from our Onshore Natural Gas Pipelines & Services segment was $18.3 million for 2003 compared to $22.1 million for 2002. The decrease in gross operating margin was primarily due to lower natural gas sales volumes attributable to an increase in natural gas prices period-to-period. Overall, natural gas throughput volumes were 600 BBtus/d during 2003 versus 701 BBtus/d during 2002. The market price of natural gas averaged $5.38 per MMBtu during 2003 versus $3.22 per MMBtu during 2002.

NGL Pipelines & Services. Gross operating margin from our NGL Pipelines & Services segment was $310.7 million for 2003 versus $181.9 million for 2002. Gross operating margin from natural gas processing increased $49.3 million period-to-period. Our results for 2002 include $51.3 million in commodity hedging losses, the underlying strategies of which were discontinued in 2002. Our commodity hedging results for 2003 were a gain of $0.2 million.

Equity NGL production at our gas processing plants averaged 43 MBPD during 2003 compared to 73 MBPD during 2002. The decrease in equity NGL production year-to-year was largely attributable to reduced demand for NGLs, principally ethane, by the ethylene industry and higher natural gas prices relative to NGL prices, which caused most natural gas processors to minimize the amount of NGLs extracted at their facilities.

During 2003, we renegotiated a number of our natural gas processing contracts. In general, our objective has been to convert our traditional keepwhole arrangements to either margin-band/keepwhole contracts, percent-of-liquids contracts or fee-based contracts. The goal of these renegotiations is to minimize our direct exposure to the volatility of natural gas prices, especially to the extent it increases the PTR cost we would pay under traditional keepwhole arrangements to the point that processing natural gas to extract NGLs becomes uneconomical for us. When NGL extraction is uneconomical, NGLs are left in the natural gas stream to the extent allowed while keeping the natural gas in compliance with pipeline quality specifications; thus reducing the amount of NGLs available for downstream activities such as pipeline transportation and NGL fractionation.

Gross operating margin from NGL pipelines and storage increased $66.5 million period-to-period. The increase in gross operating margin was primarily due to our acquisition of Mid-America and Seminole. These two systems earned gross operating margin of $156.3 million during 2003 on aggregate net volumes of 774 MBPD. The 2002 period includes $81.1 million in gross operating margin for the five months during 2002 that we owned interests in these systems (August through December). When compared to their historical operating rates, net pipeline transportation volumes on the Mid-America and Seminole systems recorded for 2003 were lower than those reported by these systems for the full year of 2002 primarily due to decreased demand for NGLs, principally ethane, by the ethylene industry and lower NGL extraction rates at regional gas processing facilities. Excluding the contributions of Mid-America and Seminole, gross operating margin from NGL pipelines and storage was $77.3 million for 2003 versus $86 million for 2002. Net pipeline throughput volumes (excluding Mid-America and Seminole) increased to 501 MBPD during 2003 from 463 MBPD during the 2002 period.

Gross operating margin from NGL fractionation improved $12.9 million year-to-year. The increase in NGL fractionation gross operating margin is primarily due to (i) mixed NGL measurement gains we recognized during 2003 at our Mont Belvieu facility and (ii) higher percent-of-liquids revenues during 2003 at Norco attributable to the general increase in NGL prices, both of which more than offset a decline in gross operating margin from our other NGL fractionation facilities generally due to lower volumes and higher energy-related costs. Net NGL fractionation volumes decreased to 227 MBPD during 2003 from 235 MBPD during 2002. The decrease in NGL fractionation volumes period-to-period was primarily due to lower NGL extraction rates at gas processing facilities and reduced demand for NGLs by the petrochemical industry.

Petrochemical Services. Gross operating margin from our Petrochemical Services segment was $75.9 million for the 2003 period compared to $117.8 for the 2002 period. Gross operating margin from propylene fractionation declined $7.4 million year-to-year primarily due to lower petrochemical marketing margins resulting from higher feedstock and energy-related operating costs. Net propylene fractionation volumes were 57 MBPD for 2003 compared to 55 MBPD during 2002.

Gross operating margin from butane isomerization increased $6.8 million year-to-year. The increase in gross operating margin from isomerization was generally attributable to higher isomerization fees and by-product revenues, which were partially offset by lower volumes and higher energy-related operating costs. Isomerization volumes were 77 MBPD during the 2003 period compared to 84 MBPD during the 2002 period.

Our equity and consolidated earnings from octane enhancement were a loss of $32.7 million for 2003 compared to equity income of $8.6 million during 2002. The $41.3 million decrease in equity earnings is primarily due to a $22.5 million impairment charge we recorded during the third quarter of 2003 for our share of an impairment charge recorded by BEF; increased downtime during 2003 for maintenance and economic reasons; and an overall decrease in MTBE sales margins. Net MTBE production from this facility decreased to 4 MBPD during 2003 from 5 MBPD during 2002.

Offshore Pipelines & Services. Gross operating margin from our Offshore Pipelines & Services segment was $5.6 million for 2003 compared to $10.5 million for 2002. Overall, natural gas throughput volumes were 433 BBtus/d during 2003 versus 500 BBtus/d during 2002. The decrease in gross operating margin is primarily due to a $4.8 million reduction in equity earnings from Starfish related to the settlement of a rate case in 2002.

Selling, general and administrative costs. These expenses were $37.6 million for 2003 compared to $42.9 million during 2002. The 2002 period includes approximately $10.0 million that we paid to Williams for transition services associated with our acquisition of Mid-America and Seminole compared to $2.0 million paid in 2003 for these services. These payments ceased in February 2003 when we began operating these two pipeline systems.

Interest expense. Interest expense increased to $140.8 million during 2003 from $101.6 million in 2002. The increase is primarily due to additional debt we incurred as a result of business acquisitions. Interest expense for 2003 includes $11.3 million of loan cost amortization related to the 364-Day Term Loan, which was incurred in July 2002 and fully repaid in February 2003. Our weighted-average debt principal outstanding was $2.0 billion during 2003 compared to $1.8 billion during 2002.

General outlook for 2005

We expect our business to be affected by the following key trends and events during 2005. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our expectations may vary materially from actual results.

- Drilling activity in the major producing areas, including the deepwater Gulf of Mexico, Rocky Mountains and San Juan, and the improving economy, have increased demand for our integrated midstream energy services. Over the next two years we expect large volumes of new production from both the deepwater and the Rockies to flow into our integrated system of assets.

  Our natural gas and NGL facilities in central Louisiana and our 50% owned Cameron Highway oil pipeline began receiving first production from the Mad Dog and Holstein developments in the Southern Green Canyon area of the deepwater Gulf of Mexico. These volumes, along with oil volumes received by our 36% owned Poseidon oil pipeline from the Front Runner development, should steadily increase during 2005 as these developments ramp up to full production. In addition, we expect initial production from the K-2 and K-2 North fields to begin flowing into our facilities in mid-2005.

- As a result of the continued strong demand for NGLs, most of our pipelines, fractionators and processing plants should continue to run at high utilization rates. The strength of the domestic and global economic recoveries should continue to drive increased demand for all forms of energy despite higher commodity prices. Our largest NGL consuming customers in the ethylene industry have seen strong demand for their products, which has enabled 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 of the ethylene industry. With strong demand for their products, the ethylene industry has been operating at utilization rates in excess of 90%, which results in strong demand for all ethylene feedstocks.

- As a result of the GulfTerra Merger, we significantly increased our midstream assets located in the Gulf of Mexico. We have several projects that have either recently started operations or are scheduled to become operational soon. For additional information regarding these projects and our other capital spending, please read “*Our Liquidity and Capital Resources — Capital Spending*.”

- The effects of Hurricane Ivan have reduced volumes delivered to some of our pipelines, natural gas processing and NGL fractionation facilities in eastern Louisiana since the middle of September 2004. We estimate that this reduction in volumes resulted in a $24 million decrease in gross operating margin for the year ended December 31, 2004. This amount is prior to any potential recoveries under our business interruption insurance. In December 2004, volumes to these pipelines and facilities started to increase and we expect the volumes to return to normal levels by mid-2005.

OUR 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. 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 partnership equity and public or private placement debt. We expect to fund cash distributions to partners primarily with operating cash flows. For additional information regarding our quarterly cash distributions, please read Item 5 of this annual report. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

As noted above, certain of our liquidity and capital resource requirements are fulfilled by borrowings made under debt agreements and/or proceeds from the issuance of additional partnership equity. At December 31, 2004, we had approximately $4.3 billion in principal outstanding under various debt agreements. For additional information regarding our debt, please read "- *Our debt obligations*."

As a result of our growth objectives, we expect to access debt and equity capital markets from time-to-time and we believe that additional financing arrangements to support our goals 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.

Registration Statements

In February 2001, we filed a universal shelf registration with the SEC covering the issuance of up to $500 million of partnership equity or public debt obligations. In October 2002, we sold 9,800,000 common units under this shelf registration statement from which we received net proceeds of $182.5 million, including Enterprise GP's proportionate net capital contribution of $3.7 million. In January 2003, we sold an additional 14,662,500 common units under this shelf registration from which we received net proceeds of $258.1 million, including Enterprise GP's proportionate net capital contribution of $5.2 million. We used the net proceeds from these equity offerings to reduce debt outstanding under our 364-Day Term Loan and for working capital purposes. After deducting for these issuances of common units in October 2002 and January 2003, practically all of the available capacity under this shelf registration statement was used.

In January 2003, we filed a new $1.5 billion universal shelf registration statement with the SEC covering the issuance of an unallocated amount of partnership equity or public debt obligations (separately or in combination). Sine June 2003, we have sold 63,410,317 common units under this registration statement.

- In June 2003, we sold 11,960,000 common units under this shelf registration statement from which we received net proceeds of $261.1 million, including Enterprise GP's proportionate net capital contribution of $5.2 million. We used the net proceeds from this offering to reduce indebtedness outstanding under our revolving credit facilities.

- In May 2004, we sold 17,250,000 common units under this registration statement from which we received net proceeds of $353.1 million, including Enterprise GP's proportionate net capital contribution of $7.1 million. We used the proceeds from this public offering to repay the $225 million Interim Term Loan and to temporarily reduce borrowings outstanding under our revolving credit facilities.

- In August 2004, we sold 17,250,000 common units under this registration statement from which we received net proceeds of $341.2 million, including Enterprise GP's proportionate net capital contribution of $6.8 million. We used $210 million of the proceeds from this public offering to reduce borrowings outstanding under our revolving credit facilities and the remainder to fund our payment obligations to El Paso under Step Two of the GulfTerra Merger.

- In October and November 2004, we sold 1,950,317 common units under this registration statement from which we received net proceeds of $39.6 million, including Enterprise GP's proportionate net capital contributions. These common units were issued as a result of the conversion of GulfTerra's 80 outstanding Series F2 convertible units, which we assumed as a result of the merger, into Enterprise common units.

- In February 2005, we sold 17,250,000 common units under this registration statement (including the over-allotment amount of 2,250,000 common units which closed on March 11, 2005) from which we received net proceeds of approximately $456.5 million, including Enterprise GP's proportionate net capital contribution of $9.1 million. We used the proceeds from this public offering to repay our 364-Day Acquisition Credit Facility, to temporarily reduce indebtedness outstanding under our Multi-Year Revolving Credit Facility or for general partnership purposes.

After deducting for these issuances of common units in 2003, 2004 and 2005, practically all of the available capacity under this shelf registration statement has been used. On March 3, 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of partnership equity and public debt obligations. In connection with this registration statement, we also registered for resale 36,572,122 common units currently owned by Shell and 4,427,878 common units owned by third party, Kayne Anderson. Shell sold these unregistered units to Kayne Anderson in December 2004. We are obligated to register the resale of these common units for Shell under a registration rights agreement we executed with Shell in connection with our acquisition of certain of Shell's Gulf Coast midstream energy businesses in September 1999.

In July 2003, we filed a registration statement with the SEC covering 5,000,000 common units issuable under the Distribution Reinvestment Plan (or "DRIP"). In April 2004, we filed a new registration statement with the SEC covering an additional 10,000,000 common units issuable under the DRIP. The new registration statement increased the number of common units issuable under the DRIP from 5,000,000 to 15,000,000. 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 in the purchase of additional common units. We expect to use the cash generated from this reinvestment program primarily for general partnership purposes. Initial reinvestments under the DRIP occurred in August 2003. For all of 2003, we issued 2,883,803 common units in connection with the DRIP and received proceeds (including Enterprise GP's proportionate net capital contributions) of approximately $60.3 million. During 2004, we issued 5,183,591 common units in connection with the DRIP and received proceeds (including Enterprise GP's proportionate net capital contributions) of approximately $111.6 million. To support our growth objectives and financial flexibility, EPCO reinvested approximately $177.5 million of its cash distributions from August 2003 through February 2005 through the DRIP.

Class B special units

In December 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO for $100 million in a private transaction. Enterprise GP contributed approximately $2 million in connection with this offering in order to maintain its ownership interest. We used the net proceeds from this offering to repay $100 million of the debt we incurred to finance our December 2003 purchase of a 50% interest in GulfTerra GP and the remainder for general partnership purposes. Upon receipt of unitholder approval on July 29, 2004, our 4,413,549 Class B special units converted to an equal number of common units. This conversion resulted in a reclassification of the $99 million capital account balance for the Class B special units to common units.

Series F2 convertible units assumed in connection with the GulfTerra Merger

In May 2003, GulfTerra issued 80 Series F convertible units in a registered offering to an institutional investor. Each Series F convertible unit was comprised of two separate detachable units — a Series F1 convertible unit and a Series F2 convertible unit — that had identical terms except for vesting and termination dates and the number of common units into which they may be converted. Prior to the GulfTerra Merger, all the Series F1 convertible units were converted. As a result of the GulfTerra Merger, we assumed GulfTerra's obligations associated with the 80 Series F2 convertible units. All Series F2 convertible units outstanding at the merger date were converted into rights to receive Enterprise common units. The number of Enterprise common units and the price per unit at conversion were adjusted based on the 1.81 exchange ratio. The Series F2 convertible units were convertible into up to $40 million of Enterprise common units.

On October 29, 2004, 60 of the 80 outstanding Series F2 convertible units were converted into 1,458,434 Enterprise common units. As a result of this conversion, we received a payment of $30 million from the holder of the Series F2 convertible units (representing a conversion price of $20.57 per Enterprise common unit). Net proceeds from this conversion, including Enterprise GP's proportionate capital contribution of $0.6 million, were $29.7 million after deducting transaction costs of $0.9 million.

On November 8, 2004, the remaining 20 outstanding Series F2 convertible units were converted into 491,883 Enterprise common units. As a result of this conversion, we received a payment of $10 million from the holder of the Series F2 convertible units (representing a conversion price of $20.33 per Enterprise common unit). Net proceeds from this conversion, including Enterprise GP's proportionate capital contribution of $0.2 million, were $9.9 million after deducting transaction costs of $0.3 million.

CASH FLOWS FROM OPERATING, INVESTING AND FINANCING ACTIVITIES

The following discussions highlight significant year-to-year comparisons in consolidated operating, investing and financing cash flows:

	For Year Ended December 31,		
	2004	2003	2002
Net income	$ 268,261	$ 104,546	$ 95,500
Adjustments to reconcile net income to cash flows provided by (operating activities before changes in operating accounts):			
Depreciation and amortization in operating costs and expenses	193,734	115,642	86,029
Depreciation and amortization in selling, general and administrative costs	1,650	159	77
Amortization in interest expense	3,503	12,634	8,819
Equity in (income) loss of unconsolidated affiliates	(52,787)	13,960	(35,253)
Distributions received from unconsolidated affiliates	68,027	31,882	57,662
Provision for impairment of long-lived asset	4,114	1,200	
Gain on sale of assets	(15,901)	(16)	(1)
Cumulative effect of changes in accounting principles	(10,781)		
Changes in fair market value of financial instruments	5	(29)	10,213
Increase in restricted cash	(12,305)	(5,100)	(2,999)
Other	25,441	23,839	14,060
Cash flow from operating activities before changes in operating accounts	472,961	298,717	234,107
Net effect of changes in operating accounts	(93,725)	120,888	92,655
Operating activities cash flows	$ 379,236	$ 419,605	$ 326,762

Cash flows from operating activities primarily reflect net income adjusted for depreciation, amortization and similar non-cash amounts; equity earnings and cash distributions from unconsolidated affiliates and changes in operating accounts. The net effect of changes in operating accounts is generally the result of timing of cash receipts from sales and cash payments for purchases and other expenses near the end of each period. For additional information regarding changes in operating accounts, please read Note 17 of the Notes to Consolidated Financial statements included under Item 8 of this annual report.

In addition, operating cash inflows and outflows related to increases or decreases in inventory are influenced by changes in commodity prices and our marketing activities. Cash flow from operations is primarily based on earnings from our business activities. As a result, these cash flows are exposed to certain risks.

We operate predominantly in the midstream energy sector, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs and crude oil. In general, we provide services for producers and consumers of natural gas, NGLs and crude oil from the wellhead to the end user. 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. Other risks include fluctuations in oil, natural gas and NGL prices, competitive practices in the midstream energy industry and the impact of operational and systems risks. For a more complete discussion of these and other risk factors pertinent to our business, please read “*Risk Factors*” included within this Item 7 discussion.

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

Operating activities. Cash provided by operating activities was $379.2 million during 2004 compared to $419.6 million for 2003. As shown in the preceding table, cash flow before the net effect of changes in operating accounts was an inflow of $473 million for 2004 versus $298.7 million for 2003. We believe that cash flow from operating activities before the net effect of changes in operating accounts is an important measure of our ability to generate core cash flows from our assets and other investments. The $174.3 million increase in this element of our cash flows is primarily due to:

- earnings from the assets we acquired in the GulfTerra Merger and in our purchase of the South Texas midstream assets, which occurred on September 30, 2004;
- the 2004 period including a gain on sale of assets of approximately $15.1 million related to the satisfaction of certain contractual requirements of a joint venture participation agreement whereby a 50% interest in Cameron Highway was sold; offset by
- higher interest costs associated with debt incurred and issued to fund our cash payment obligations associated with the GulfTerra Merger.

Distributions received from our equity method unconsolidated affiliates were $68 million for 2004 compared to $31.9 million for 2003 and equity income received from our equity method unconsolidated affiliates was $52.8 million for 2004 compared to a loss of $14.0 million for 2003. The increases in these components of our cash flows is primarily due to cash distributions and equity income received from GulfTerra GP and VESCO, offset by the effects of consolidating former equity method investments as a result of acquisitions. As a result of the GulfTerra Merger, GulfTerra GP became a wholly owned subsidiary of the Operating Partnership (see Note 4 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report). Additionally, 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 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report). The period-to-period fluctuation in the restricted cash balance is primarily due to the timing of physical purchases of natural gas on the NYMEX exchange.

Investing activities. During 2004, we used $929.1 million in cash for investing activities compared to $657 million in 2003. We used $638.8 million during 2004 to complete the GulfTerra Merger, including our purchase of the South Texas midstream assets. Additionally, during 2004, we used $85.9 million to purchase certain assets located near Morgan’s Point, Texas, an additional 16.7% membership interest in Tri-States, a 10% equity interest in Seminole and the remaining 33.3% ownership interest in BEF. During 2003, we used $37.3 million primarily to purchase the Port Neches Pipeline, the remaining 50% ownership interest in EPIK, an additional 33.3% interest in BEF, an additional 37.4% interest in Wilprise and the remaining 50% interest in OTC. Capital expenditures were $146.9 million for 2004 versus $145.9 million for 2003. For additional information regarding our capital expenditures, please read “*Capital Spending*” included within this Item 7. Investments in and advances to unconsolidated affiliates were $64.4 million for 2004 compared to $471.9 million for 2003. During 2004, we used $27.5 million to purchase an additional 16.7% interest in Promix and we contributed $24 million to Cameron Highway for the construction of the Cameron Highway oil pipeline. The 2003 period included our payment of $425 million to El Paso for a 50% ownership interest in GulfTerra GP and amounts we contributed to our Gulf of Mexico natural gas pipeline investments for their expansion capital projects.

Financing activities. Cash provided by financing activities during 2004 was $544 million compared to $254 million in 2003. During 2004, we had net borrowings under our debt agreements of $125.6 million compared to net repayments of $106.8 million for 2003. On September 30, 2004, we borrowed approximately $2.8 million under our new 364-Day Acquisition Credit Facility and Multi-Year Revolving Credit Facility to (a) fund $655.3 million in cash payment obligations to El Paso under Steps Two and Three of the GulfTerra Merger transactions, (b) escrow $1.1 billion to finance our tender offers for GulfTerra’s senior and senior subordinated notes and (c) extinguish $962 million outstanding under GulfTerra’s revolving credit facility and secured term loans. Additionally, on October 4, 2004, we issued $2 billion in senior notes (Senior Notes E, F, G and H). Our repayments of debt during 2004 reflect the use of proceeds from our May 2004 and August 2004 equity offerings to repay the $225 million Interim Term Loan and to temporarily reduce amounts outstanding under our pre-merger revolving credit facilities and the use of proceeds from our October 2004 issuance of senior notes to reduce debt amounts outstanding under our 364-Day Acquisition Credit Facility. Additionally, on October 5, 2005, we used the $1.1 billion in escrowed funds to complete our cash tender offers for substantially all of GulfTerra’s senior and senior subordinated notes. The 2003 period reflects our issuance of Senior Notes C ($350 million in principal amount) and Senior Notes D ($500 million in principal amount), and a $425 million borrowing under our Interim Term Loan which was used to purchase a 50% interest in GulfTerra GP. Repayments of debt during 2003 reflect the use of proceeds from equity offerings completed in January, June, August and December and the final repayment of

$1 billion that was outstanding under the bridge loan financing we used to purchase interest in the Mid-America and Seminole pipelines.

Cash distributions to partners increased from $309.9 million during 2003 to $438.8 million during 2004. The increase in cash distributions is primarily due to an increase in both the declared quarterly distribution rates and the number of units eligible for distributions. We expect that future cash distributions to partners will increase as a result of our periodic issuance of common units under the DRIP and other equity offerings.

Net proceeds from the issuance of common units were $846.1 million for 2004 compared to $573.7 million for 2003. Both amounts include Enterprise GP's net proportionate capital contributions. In May 2004, we sold 17,250,000 common units to the public (including the underwriters' over-allotment amount of 2,250,000 common units) at an offering price of $21.00 per unit. Net proceeds from this offering, including Enterprise GP's proportionate net capital contribution of $7.1 million, were $353.1 million after deducting applicable underwriting discounts, commissions and offering expenses of $16.3 million. In August 2004, we sold 17,250,000 common units to the public (including the underwriters' over-allotment amount of 2,250,000 common units) at an offering price of $20.20 per unit. Net proceeds from this offering, including Enterprise GP's proportionate net capital contribution of $6.8 million, were approximately $341.2 million after deducting applicable underwriting discounts, commissions and offering expenses of $13.9 million. The 2004 period also includes $111.6 million in proceeds from the sale of 5,183,591 common units in connection with the DRIP, the proceeds of which were primarily used for general partnership purposes, and $39.6 million in proceeds from the conversion of 80 Series F2 convertible units into 1,950,317 common units. Proceeds from the issuance of common units during 2003 reflect the sale of 14,662,500 and 11,960,000 common units in our January 2003 and June 2003 equity offerings, respectively, and the sale of 2,883,803 common units in connection with the DRIP. Additionally, the 2003 period reflects the sale of 4,413,549 Class B special units to an affiliate of EPCO in December 2003.

Comparison of Year Ended December 31, 2003 with Year Ended December 31, 2002

Operating cash flows. Cash provided by operating activities was $419.6 million during 2003 compared to $326.8 million during 2002. As shown in the preceding table, cash flow before the net effect of changes in operating accounts was an inflow of $298.7 million during 2003 versus $234.1 million during 2002. The $64.6 million increase in this element of our cash flows is primarily due to:

- earnings from newly acquired businesses which are included in the 2003 period but not in the 2002 period (particularly those of Mid-America and Seminole, which we acquired in July 2002);
- the 2002 period including $51.3 million of commodity hedging losses versus $0.6 million of such losses during the 2003 period; offset by
- higher interest costs associated with debt we incurred and issued since the first quarter of 2002 to finance acquisitions.

Distributions and equity income received from our equity method unconsolidated affiliates during 2003 decreased $25.8 million and $49.2 million, respectively, over those received in 2002. The decreases in these components of our cash flows are primarily due to consolidating former equity method investments as a result of acquisition. Additionally, the 2003 period reflects a decrease in equity earnings from BEF primarily due to a $22.5 million asset impairment charge we recorded during the third quarter of 2003.

Investing cash flows. During 2003, we used $657.0 million in cash for investing activities compared to $1.7 billion during 2002. We used $37.3 million and $1.6 billion for business acquisitions during 2003 and 2002, respectively. The 2002 period reflects our acquisition of interests in the Mid-America and Seminole pipelines from Williams and propylene fractionation and NGL and petrochemical storage assets from Diamond-Koch. The 2003 period includes only minor acquisitions, specifically the Port Neches pipeline and additional interests in EPIK, BEF, Wilprise and OTC.

Investments in and advances to unconsolidated affiliates increased to $471.9 million during 2003 compared to $13.7 million during 2002. The 2003 period includes our payment of $425 million to El Paso for a 50%

ownership interest in the general partner of GulfTerra in December 2003. The remaining $33.2 million year-to-year increase is primarily due to funding our share of the expansion projects of our Gulf of Mexico natural gas pipeline investments and our purchase of an additional interest in Tri-States.

Our capital expenditures were $145.9 million during 2003 versus $72.1 million during 2002. The $73.8 million increase in capital expenditures is primarily due to expansions of our Norco NGL fractionator and Neptune gas processing facility.

Financing cash flows. Cash provided by financing activities during 2003 was $254 million compared to $1.3 billion during 2002. During 2003, we made net payments on our debt obligations of $106.8 million. Our borrowings during 2003 include the issuance of Senior Notes C ($350 million in principal amount), Senior Notes D ($500 million in principal amount) and the $425 million borrowing under the Interim Term Loan (to purchase a 50% interest in the general partner of GulfTerra). Our repayments during 2003 include the use of proceeds from equity offerings completed in January, June, August and December. The 2002 period primarily reflects borrowings to fund the Mid-America and Seminole acquisitions and those of Diamond-Koch's propylene fractionation business.

Proceeds from our common unit and Class B special unit equity offerings during 2003 totaled $675.7 million, which includes Enterprise GP's related $7.8 million contribution to us. Enterprise GP also contributed $5.9 million to our Operating Partnership in connection with these offerings. Distributions to our partners and minority interests increased to $318.0 million during 2003 from $218.2 million during 2002. The $99.8 million increase in distributions to partners is primarily due to increases in both the declared quarterly distribution rates and the number of units eligible for distributions.

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OUR DEBT OBLIGATIONS

Our debt consisted of the following at the dates indicated:

	December 31, 2004	December 31, 2003
Operating Partnership debt obligations:		
Interim Term Loan, variable rate, repaid in May 2004(1)		$ 225,000
364-Day Revolving Credit Facility, variable rate, terminated in September 2004(2)		70,000
Multi-Year Revolving Credit Facility, variable rate, terminated in September 2004(2)		115,000
364-Day Acquisition Credit Facility, variable rate, repaid in February 2005(3, 4)	$ 242,229	
Multi-Year Revolving Credit Facility, variable rate, due September 2009(2,4)	321,000	
Seminole Notes, 6.67% fixed-rate, $15 million due in December 2005(5)	15,000	30,000
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	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	
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	
GulfTerra debt obligations:(5)		
Senior Notes, 6.25% fixed-rate, due June 2010 (6)	750	
Senior Subordinated Notes, 8.50% fixed-rate, due June 2010	3,858	
Senior Subordinated Notes, 8.50% fixed-rate, due June 2011	1,777	
Senior Subordinated Notes, 10.625% fixed-rate, due December 2012	84	
Total principal amount	4,288,698	2,144,000
Net unamortized discounts	(9,239)	(5,983)
Other	1,777	1,531
Subtotal long-term debt	4,281,236	2,139,548
Less current maturities of debt(7)	(15,000)	(240,000)
Long-term debt	$ 4,266,236	$ 1,899,548
Standby letters of credit outstanding(8)	$ 139,052	$ 1,300

(1) We used the proceeds from our May 2004 common unit offering to fully repay and terminate the Interim Term Loan.

(2) These facilities were terminated on September 30, 2004, and replaced by a new Multi-Year Revolving Credit Facility having $750 million of borrowing capacity due September 2009.

(3) We used the proceeds from our February 2005 common unit offering to fully repay and terminate the 364-Day Acquisition Credit Facility.

(4) These facilities became effective concurrently with the closing of the GulfTerra Merger on September 30, 2004. The new $750 million Multi-Year Revolving Credit Facility replaced the $230 million 364-Day Revolving Credit Facility and the $270 million then existing Multi-Year Revolving Credit Facility. The $750 million borrowing capacity is reduced by the amount of standby letters of credit outstanding.

(5) Solely as it relates to the assets of our GulfTerra and Seminole subsidiaries, our senior indebtedness is structurally subordinated and ranks junior in right of payment to indebtedness of GulfTerra and Seminole.

(6) Remaining notes outstanding were called and retired in February 2005.

(7) 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 Credit Facility using proceeds from an equity offering completed in February 2005. Our classification of current maturities of debt at December 31, 2003 reflected our option and ability to convert any revolving credit balance outstanding at maturity under the 364-Day Revolving Credit Facility to a one-year term loan (which would have been due October 2005) in accordance with the terms of the agreement.

(8) Of the $139 million standby letters of credit outstanding at December 31, 2004, $24 million were issued under our Multi-Year Revolving Credit Facility, and the remaining $115 million is associated with a letter of credit facility we entered into in November 2004 in connection with our Independence Hub capital project.

General description of consolidated debt

The following is a summary of the significant aspects of our debt obligations at December 31, 2004:

Parent-Subsidiary guarantor relationships. We act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Seminole Notes and the senior and 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. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own an effective 88.4% of its capital stock). The senior and senior subordinated notes of GulfTerra are unsecured obligations of GulfTerra (of which we own 100% of its limited and general partnership interests).

GulfTerra's Senior Subordinated and Senior Notes. As a result of completing the GulfTerra Merger on September 30, 2004, we recorded in consolidation GulfTerra's $921.5 million of outstanding senior and senior subordinated notes. Of this amount, $915 million was purchased on October 5, 2004 by our Operating Partnership pursuant to its tender offers. The note holders also approved amendments in connection with accepting the tender offers that removed all restrictive covenants governing the notes. For additional information regarding the tender offers, please read " - *364-Day Acquisition Credit Facility — Tender offers for GulfTerra senior and senior subordinated notes*" within this general description of debt. In February 2005, we redeemed, at a premium, the remaining $0.8 million outstanding under GulfTerra's 6.25% senior notes due June 2010.

364-Day Acquisition Credit Facility. In August 2004, our Operating Partnership entered into a new 364-day credit agreement. The $2.25 billion Acquisition Credit Facility was an unsecured 364-day facility that was used to provide interim financing for certain transactions associated with the GulfTerra Merger, the refinancing of GulfTerra's existing secured credit facility and term loans and the purchase of GulfTerra's senior and senior subordinated notes in connection with our Operating Partnership's tender offers for those notes. This facility became effective concurrent with the closing of the GulfTerra Merger and was to mature on September 29, 2005. In February 2005, we fully repaid and terminated the 364-Day Acquisition Credit Facility using proceeds we received from our February 2005 common unit offering. For additional information regarding the February 2005 common unit offering, please read "Recent Developments" included within this Item 7 discussion.

As defined by the credit agreement, variable interest rates charged under this facility generally bore 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 credit agreement provided for the mandatory prepayment of loans and termination of commitments equal to the proceeds from and upon the consummation of any public or private debt or equity offerings by us on or after August 15, 2004, excluding equity issued with respect to our distribution reinvestment plan, employee unit purchase plan and the exercise of any outstanding options with respect to our common units. With the completion of our private offering of senior notes on October 4, 2004, we repaid approximately $2 billion borrowed under this facility, which reduced our borrowing capacity under this facility by an equal amount.

This revolving credit agreement contained 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 required us to satisfy certain financial covenants at the end of each fiscal quarter. We are in compliance with these covenants at December 31, 2004.

Tender offers for GulfTerra senior and senior subordinated notes

On August 4, 2004, in anticipation of completing the GulfTerra Merger, our Operating Partnership commenced four cash tender offers to purchase any and all of the outstanding senior and senior subordinated notes of GulfTerra having a total outstanding principal amount of approximately $921.5 million. In connection with the tender offers, GulfTerra executed supplements to the indentures governing these notes that eliminated certain restrictive covenants and default provisions contained in those indentures upon our purchase of more than a majority in principal amount of each series of the outstanding senior and senior subordinated notes.

Substantially all of the GulfTerra notes ($915 million of $921.5 million) were tendered pursuant to the tender offers. On September 30, 2004, we borrowed $1.1 billion under our 364-Day Acquisition Credit Facility in anticipation of completing the tender offers and placed these funds in escrow. On October 5, 2004, our Operating Partnership purchased the notes for a total price of approximately $1.1 billion, which included $27 million related to consent payments.

The following table shows the four GulfTerra senior debt obligations affected, including the principal amount of each series of notes tendered, as well as the payment made by Enterprise to complete the tender offers.

Description	Principal Amount Tendered	Cash payments made by Enterprise		
		Accrued Interest	Tender Price (1)	Total Paid
8.50% Senior Subordinated Notes due 2010				
(Represents 98.2% of principal amount outstanding)	$ 212,057	$ 6,209	$ 246,366	$ 252,575
10.625% Senior Subordinated Notes due 2012				
(Represents 99.9% of principal amount outstanding)	133,916	4,901	167,612	172,513
8.50% Senior Subordinated Notes due 2011				
(Represents 99.5% of principal amount outstanding)	319,823	9,364	359,379	368,743
6.25% Senior Notes due 2010				
(Represents 99.7% of principal amount outstanding)	249,250	5,366	274,073	279,439
Totals	$ 915,046	$ 25,840	$ 1,047,430	$ 1,073,270

(1) Tender price includes consent payment of $30 per $1,000 principal amount tendered.

Multi-Year Revolving Credit Facility. In August 2004, our Operating Partnership entered into a five-year $750 million revolving credit agreement that includes a sublimit of $100 million for standby letters of credit. This facility became effective concurrent with the closing of the GulfTerra Merger and will mature on September 30, 2009. This facility replaced our then existing $270 million Multi-Year Revolving Credit Facility and $230 million 364-Day Revolving Credit Facility, which were terminated upon the effective date of the new facility. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to Enterprise 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 similar to those of our 364-Day Acquisition Credit Facility. We are in compliance with these covenants at December 31, 2004.

Senior Notes A, B, C and D. These fixed-rate notes are an unsecured obligation 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 GP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. These notes 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. We were in compliance with these covenants at December 31, 2004. On March 15, 2005, we repaid the $350 million in indebtedness outstanding under Senior Notes A, using the proceeds we received from our issuance of Senior Notes I and J.

Senior Notes E, F, G and H. On September 23, 2004, our Operating Partnership priced a private offering of an aggregate of $2 billion in principal amount of senior unsecured notes in a transaction exempt from the registration requirements under the Securities Act of 1933, as amended. On October 4, 2004, these notes were issued. The interest rate, principal amount and net proceeds, before expenses, for each senior note in this offering are shown in the following table:

Senior Note Issued	Fixed Interest Rate	Principal Amount	Bond Discount	Proceeds to Us, Before Expenses
Senior Notes E, due October 2007	4.000%	$ 500,000	$ 2,140	$ 497,860
Senior Notes F, due October 2009	4.625%	500,000	4,405	495,595
Senior Notes G, due October 2014	5.600%	650,000	4,784	645,216
Senior Notes H, due October 2034	6.650%	350,000	4,203	345,797
Totals		$ 2,000,000	$ 15,532	$ 1,984,468

The net proceeds from this offering were used to reduce debt amounts outstanding under the Operating Partnership's $2.25 billion 364-Day Acquisition Credit Facility that was used to partially fund the GulfTerra Merger on September 30, 2004.

These fixed-rate notes are unsecured obligations of our Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. The Operating Partnership's borrowings under these notes are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. These notes were issued under an indenture containing certain covenants, which restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. We are in compliance with these covenants at December 31, 2004.

On January 24, 2005, we filed a registration statement for an offer to exchange these notes for registered debt securities with identical terms. The exchange of notes was completed in March, 2005.

Senior Notes I and J. On February 15, 2005, our Operating Partnership sold $500 million in principal amount of senior notes in a private offering, comprised of $250 million in principal amount of 10-year senior unsecured notes and $250 million in principal amount of 30-year senior unsecured notes. The 10-year notes ("Senior Notes I") were issued at 99.379% of their principal amount and have fixed-rate interest of 5.00% and a maturity date of March 1, 2015. The 30-year notes ("Senior Note J") were issued at 98.691% of their principal amount and have fixed-rate interest of 5.75% and a maturity date of March 1, 2035. The Operating Partnership used the net proceeds from the issuance of Senior Notes I and J to repay $350 million of indebtedness outstanding under Senior Notes A which was due on March 15, 2005, and the remaining proceeds for general partnership purposes, including the temporary repayment of indebtedness outstanding under the Multi-Year Revolving Credit Facility.

Pascagoula MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, our 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. We were in compliance with the covenants at December 31, 2004.

The indenture agreement for this loan contains an acceleration clause whereby if our credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's remaining at BB+ or below, 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.

Industrial Development Revenue Bonds. In April 2004, Petal Gas Storage L.L.C. ("Petal"), a wholly owned subsidiary of GulfTerra, borrowed $52 million from the Mississippi Business Finance Corporation ("MBFC") pursuant to a loan agreement between Petal and the MBFC. On the same date, the MBFC issued $52 million in Industrial Development Revenue Bonds to another wholly owned subsidiary of GulfTerra. The loan agreement and the Industrial Development Revenue Bonds have identical fixed interest rates of 6.25% and maturities of fifteen years. The bonds and the associated tax exemptions are authorized under the Mississippi Business Finance Act. Petal may repay the loan agreement without penalty, and thus cause the Industrial Development Revenue Bonds to be redeemed, any time after one year from their date of issue. We have netted the loan amount and the bond amount of $52 million and the interest payable and interest receivable amount of $2.2 million on our Consolidated Balance Sheet as of December 31, 2004. Beginning in the fourth quarter of 2004, we also netted the interest expense and interest income amounts of $0.8 million attributable to these instruments on our Statements of Consolidated Operations. Our presentation of the Industrial Development Revenue Bonds is reflected in accordance with the provisions of FIN No. 39, "*Offsetting of Amounts Related to Certain Contracts*", and SFAS No. 140, "*Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*", since we have the ability and intent to offset these items.

Loss due to write-off of unamortized debt issuance costs. As a result of terminating our 364-Day Revolving Credit Facility and our previous Multi-Year Revolving Credit Facility on September 30, 2004, we expensed $0.7 million of unamortized debt issuance costs.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable-rate debt obligations during 2004.

	Range of interest rates paid	**Weighted-average interest rate paid**
Interim Term Loan (terminated May 2004)	1.72% to 1.78%	1.76%
364-Day Revolving Credit Facility (terminated September 30, 2004)	1.72% to 4.00%	1.82%
Multi-Year Revolving Credit Facility (terminated September 30, 2004)	1.67% to 4.25%	1.83%
364-Day Acquisition Credit Facility (effective September 30, 2004)	2.67% to 4.75%	3.50%
Multi-Year Revolving Credit Facility (effective September 30, 2004)	2.64% to 5.25%	3.06%

Consolidated debt maturity table

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

Fiscal 2005	$ 15,000
" 2007	500,000
" 2009	821,000
Thereafter	2,952,698
Total scheduled principal to be repaid	$ 4,288,698

In accordance with SFAS No. 6, "*Classification of Short-Term Obligations Expected to Be Refinanced*", the amount shown in the table above for 2005 excludes the $242.2 million principal amount due under our 364-Day Acquisition Credit Facility at December 31, 2004. We refinanced this short-term obligation using proceeds from an equity offering completed in February 2005. As a result, we have reclassified this amount to long-term debt and shown it as a component of principal amounts due after 2009.

In addition, the long-term portion of our debt obligations at December 31, 2004 reflects our refinancing of the $350 million in principal amount Senior Notes A (due March 2005) with proceeds from our issuance in March 2005 of $250 million in principal amount Senior Notes I (due March 2015) and our $250 million in principal amount

Senior Notes J (due March 2035). In accordance with SFAS No. 6, the principal amount due under Senior Notes A has been reclassified to amounts due after 2009 to match the scheduled maturities of Senior Notes I and J.

Joint venture debt obligations

We have ownership interests in four joint ventures having long-term debt obligations. The following table shows (i) our ownership interest in each entity at December 31, 2004, (ii) total long-term debt obligations (including current maturities) of each unconsolidated affiliate at December 31, 2004, on a 100% basis to the joint venture and (iii) the corresponding scheduled maturities of such long-term debt (dollars in thousands).

	Our Ownership Interest	Total	Scheduled Maturities of Long-Term Debt					
			2005	2006	2007	2008	2009	After 2009
Cameron Highway (1)	50.0%	$297,000		$ 8,125	$32,500	$164,375	$16,000	$76,000
Deepwater Gateway	50.0%	144,000	$22,000	22,000	22,000	22,000	56,000	
Poseidon	36.0%	107,000				107,000		
Evangeline	49.5%	35,650	5,000	5,000	5,000	5,000	5,000	10,650
Total		$583,650	$27,000	$35,125	$59,500	$298,375	$77,000	$86,650

(1) The scheduled maturities for Cameron Highway assume that the construction loan will be converted into a term loan by July 2005 and scheduled repayments will begin on December 31, 2006.

The following is a summary of the significant aspects of the debt obligations of our unconsolidated affiliates.

Cameron Highway. In July 2003, Cameron Highway entered into a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes, to finance a substantial portion of the cost to construct the Cameron Highway oil pipeline.

The construction loan bears interest at a variable rate. Once the Cameron Highway oil pipeline has commenced operations and transported a certain level of volumes (as specified in the credit agreement), the construction loan will convert to a term loan maturing in July 2008, subject to the terms of the loan agreement. At the end of the first quarter following the first anniversary of the conversion into a term loan, Cameron Highway will be required to make quarterly principal payments of $8.1 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by January 2006, the construction loan and senior secured notes become fully due and payable. At December 31, 2004, Cameron Highway had $197 million outstanding under its construction loan at an average interest rate of 5.48%.

The interest rate on Cameron Highway's senior secured notes is 3.25% over the rate on 10-year U.S. Treasury securities. Principal payments of $4 million are due quarterly from September 2008 through December 2011, $6 million each from March 2012 through December 2012, and $5 million each from March 2013 through the principal maturity date of December 2013. At December 31, 2004, Cameron Highway had $100 million outstanding under its senior secured notes at an average interest rate of 7.36%.

The project loan facility as a whole is secured by (1) substantially all of Cameron Highway's assets, including, upon conversion to a term loan, a debt service reserve capital account, and (2) all of the equity interest in Cameron Highway. Other than the pledge of our equity interest and our construction obligations under the relevant producer agreements, the debt is non-recourse to us. The construction loan and senior secured notes prohibit Cameron Highway from making distributions to us until the construction loan is converted into a term loan and Cameron Highway meets certain financial requirements.

Deepwater Gateway. In August 2002, Deepwater Gateway, our unconsolidated affiliate which owns the Marco Polo tension-leg platform, obtained a $155 million project finance loan to finance a substantial portion of the cost to construct the Marco Polo tension-leg platform and related facilities. Construction of the Marco Polo tension-leg platform was completed during the first quarter of 2004, and in June 2004, Deepwater Gateway converted the project finance loan into a term loan which matures in June 2009. The term loan is payable in twenty equal quarterly installments of $5.5 million each (which began on September 30, 2004), and the remaining outstanding principal of $45 million is due on the maturity date. Interest rates are variable and the loan is collateralized by substantially all of Deepwater Gateway's assets. Deepwater Gateway is required to maintain a debt service reserve of not less than the projected principal, interest and fees due on the term loan for the immediately succeeding six month period. If Deepwater Gateway defaults on its payment obligations under the term loan, we would be required to pay the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of December 31, 2004, the average interest rate charged under this term loan was 4.42%.

In accordance with terms of the credit agreement, Deepwater Gateway has the right to repay the principal amount plus any accrued interest due under its term loan at any time without penalty. Deepwater Gateway has decided to extinguish its term loan. We and our 50% joint venture partner in Deepwater Gateway, Cal Dive, will make equal cash contributions to Deepwater Gateway to fund the repayment. At March 9, 2005, the term loan principal amount owed by Deepwater Gateway was $144 million.

Poseidon. Poseidon is party to a $170 million revolving credit facility which matures in January 2008. The interest rates Poseidon is charged on balances outstanding under its revolving credit facility are variable and depend on its ratio of total debt to earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon's assets. As of December 31, 2004, the average interest rate charged under Poseidon's revolving credit facility was 4.58%.

Evangeline. At December 31, 2004, long-term debt for Evangeline consisted of (i) $28.2 million in principal amount of 9.9% fixed-rate Series B senior secured notes that are due in 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 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 in connection with its acquisition of a contract-based intangible asset in the early 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the note until such time as the Series B note holders are either fully cash secured through debt service accounts or have been completely repaid. In general, interest accrues on the subordinated note at a variable-rate based on LIBOR plus $^1/_2$%. The variable interest rate paid on this debt at December 31, 2004 was 1.73%.

CREDIT RATINGS

Our current corporate credit ratings are Baa3 (investment grade) with a stable outlook as rated by Moody's Investor Services; BB+ (non-investment grade) with a positive outlook as rated by Standard and Poor's and BBB- (investment grade) with a stable outlook by Fitch ratings.

Depending on our future operating results, these credit rating agencies may view our current levels of debt negatively. If one or more of these credit rating agencies were to downgrade our credit standing, we could experience an increase in our borrowing costs, difficulty accessing 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, acquisitions and to refinance indebtedness.

Additionally, if our credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's remaining at BB+ or below, the $54 million principal balance of our Pascagoula MBFC Loan, and all related accrued and unpaid interest would become immediately due and payable 120 days following such event. If such an event occurred, we would have to redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support our obligation under the Pascagoula MBFC Loan.

CAPITAL SPENDING

We have a number of ongoing capital projects, including those we assumed as a result of the GulfTerra Merger (please read "- *Significant Announced Growth Capital Projects*"). For the years ended December 31, 2004, 2003 and 2002, our capital spending for business combinations (including non-cash consideration amounts), property, plant and equipment and our unconsolidated affiliates was $3.8 billion, $655.2 million and $1.7 billion, respectively. The following table summarizes our capital spending by activity for the periods indicated:

	For Year Ended December 31,		
	2004	2003	2002
Capital spending for business combinations:			
GulfTerra Merger (Step Two transactions):			
Cash payments to El Paso	$ 500,000		
Transaction fees and other direct costs	24,032		
Cash received from GulfTerra	(40,313)		
Net cash payments	483,719		
Value of non-cash consideration issued or granted	2,910,771		
Total GulfTerra Merger Step Two consideration	3,394,490		
GulfTerra Merger (Step Three transactions):			
Cash payments to El Paso	155,277		
Mid-America and Seminole pipelines			$ 1,182,946
Propylene fractionation and hydrocarbon storage assets			368,636
Other business combinations	85,851	$ 37,348	69,145
Total capital spending related to business combinations	3,635,618	37,348	1,620,727
Capital spending for property, plant and equipment:			
Growth capital projects	114,419	125,600	64,934
Sustaining capital projects	32,509	20,313	7,201
Total capital spending for property, plant and equipment	146,928	145,913	72,135
Capital spending attributable to unconsolidated affiliates:			
Investments in and advances to unconsolidated affiliates	64,412	471,927	13,651
Total capital spending	$ 3,846,958	$ 655,188	$ 1,706,513

The preceding table reflects capital spending of $3.5 billion for the GulfTerra Merger in 2004; $425 million for our investment in GulfTerra GP in 2003; and $1.2 billion for our acquisition of the Mid-America and Seminole pipelines in 2002. Our capital spending for property, plant and equipment is reflected net of contributions in aid of construction of $8.9 million, $0.9 million and $4 million during 2004, 2003 and 2002, respectively.

We are committed to the long-term growth and viability of the Company. 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 acquisitions that will expand our system of assets and through growth capital projects. The combination of our operations with those of GulfTerra provides us with incremental growth opportunities for both onshore and offshore projects. We currently estimate that our capital spending over the next two to three years could approximate up to $2 billion, primarily for growth projects in the Gulf of Mexico and Western regions of North America. Of this amount, we expect to spend approximately $970 million during 2005.

The ability to execute our growth strategy and complete our projects is dependent upon our access to the capital necessary to fund projects and acquisitions. Our success with capital raising efforts, including the formation of joint ventures to share costs and risks, continues to be the critical factor which determines how much we actually 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 below, we may adjust the timing and amounts of projected expenditures as necessary to adapt to changes in the capital markets.

We estimate our forecasted expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to provide capital from operating cash flows or otherwise obtain the capital necessary to accomplish our operating and growth objectives. These estimates may change due to factors beyond our control, such as weather related issues, changes in supplier prices or poor economic conditions. Further, estimates may change as a result of decisions made at a later date, which may include acquisitions or decisions to take on additional partners.

As previously noted, we estimate our capital spending for property, plant and equipment during 2005 to approximate $970 million, which includes estimated expenditures of $900 million for growth capital projects and acquisitions and approximately $70 million for sustaining capital expenditures which result from improvements to and major renewals of existing assets. The following table summarizes our forecasted expenditures during 2005 for announced acquisitions and significant growth capital projects (in millions of dollars):

Growth Capital Projects:	
Independence Hub Platform	$ 160.3
Independence Trail Pipeline System	159.8
Constitution Gathering System	126.7
San Juan Optimization Project	30.0
NGL Expansion Projects	29.7
Iso-Octane Conversion Project	12.7
Petal Conversion Project	11.9
Acquisitions:	
Additional interests in Dixie Pipeline Company (1)	70.9
Indian Springs natural gas gathering and processing assets (1)	74.5
Total	$ 676.5

(1) For information regarding these acquisitions, please read "Recent Developments," included within this Item 7.

We also expect to invest approximately $7.5 million in the capital projects of our unconsolidated affiliates during 2005. As of December 31, 2004, we had approximately $70 million in outstanding purchase commitments related to our share of capital projects, the majority of which pertain to pipeline and platform growth projects in the Gulf of Mexico.

Significant Announced Growth Capital Projects

Prior to the GulfTerra Merger, GulfTerra had a number of midstream energy projects underway. In addition, we have announced various new growth capital projects that are currently underway. The following is a discussion of our significant growth capital projects, including those acquired with in the GulfTerra Merger:

Independence Hub Platform and Independence Trail Pipeline System. In November 2004, we entered into an agreement with the Atwater Valley Producers Group (consisting of Anadarko, Dominion, Kerr-McGee, Spinnaker and Devon) for the dedication, processing and gathering of natural gas and condensate production from several natural gas fields in the Atwater Valley, DeSoto Canyon and Lloyd Ridge areas (collectively, the "anchor fields") of the deepwater Gulf of Mexico. We will design, construct, and own Independence Hub, a 105-foot deep-draft, semi-submersible platform with a two-level production deck, which will be capable of processing 850 MMcf/d of natural gas. The platform, which is estimated to cost approximately $385 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 to sell them a 20% indirect interest in the Independence Hub platform. Under the terms of the agreement, we will have access to Cal Dive's fleet of vessels, which will assist us in the construction of the Independence Hub platform and the related export pipeline.

Independence Hub platform will be located on Mississippi Canyon Block 920, in a water depth of 8,000 feet. This location was selected for the permanently anchored platform based on favorable seafloor conditions and proximity to the identified anchor fields. First production is expected in 2007. Under the terms of the agreement, the production fields served by the Independence Hub platform will include the dedicated anchor fields in addition to future discoveries on surrounding undeveloped blocks.

Additionally, we will construct, own, and operate the 134-mile Independence Trail natural gas pipeline system, which will have a throughput capacity of approximately 850 MMcf/d of natural gas. The pipeline system, which is estimated to cost $280 million, will transport production from the Independence Hub platform to the Tennessee Gas Pipeline. We entered into an agreement with Tennessee Gas Pipeline under which they will pay us $15 million for contributions in aid of construction to connect the Independence Trail natural gas pipeline system to their pipeline system. In November 2004, Tennessee Gas Pipeline reimbursed us $7 million for construction costs incurred. The balance of $8 million would be reimbursed by Tennessee Gas Pipeline when additional costs are incurred and is contingent upon our completion of the Independence Trail project, which is expected during 2006.

Constitution Gathering System. In July 2004, GulfTerra entered into a definitive agreement to construct, own, and operate oil and natural gas pipelines to provide production gathering services for the Constitution field, which is 100% owned by Kerr-McGee. The Constitution field is located at a depth of 5,300 feet in Green Canyon Blocks 679 and 680 in the Central Gulf of Mexico. The new $53.4 million natural gas pipeline will be a 32-mile, 16-inch pipeline with a transport capacity of up to 200 MMcf/d and will connect to our existing Anaconda Gathering System. The new $76.2 million oil pipeline will be a 70-mile, 16-inch pipeline with a minimum transport capacity of 80 MBPD that will connect with the Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at our Ship Shoal 332B platform. These pipelines are expected to start transporting volumes in the first half of 2006.

San Juan Optimization Project. In May 2003, we commenced a project relating to our San Juan Basin assets. This project, which is estimated to cost approximately $43 million, is expected to be completed in stages through 2006 and will result in increased capacity of up to 130 MMcf/d on our San Juan natural gas gathering system and increased market opportunities through a new interconnect at the tailgate of our Chaco plant.

Rocky Mountain NGL pipeline expansion and related NGL fractionation projects. In January 2005, we started a project to expand our Mont Belvieu NGL fractionator to accommodate increased production of NGLs being transported to Mont Belvieu from the Rocky Mountain area. Our Mont Belvieu facility's current fractionation capacity is up to 210 MBPD of mixed NGLs. This project, which is expected to be completed in the first quarter of 2006 at an estimated total cost of $34.2 million, will increase total fractionation capacity at this facility by 15 MBPD and reduce its energy costs. Additionally, we are reviewing a proposal to construct a new NGL fractionator at our Mont Belvieu complex that could add an additional 60 MBPD of fractionation capacity at this industry hub.

Currently, the Rocky Mountain segment of our Mid-America pipeline system transports up to 225 MBPD of NGLs from the major producing basins in Wyoming, Utah, Colorado and New Mexico to the Hobbs station on the Texas-New Mexico border. The Western Expansion Project would increase the capacity of this pipeline to 275 MBPD. Permitting, engineering and design work are in progress. We submitted a draft environmental assessment and plan of development to the appropriate regulatory agencies during the first quarter of 2005. Contingent upon receiving all required permits and regulatory approvals, construction could begin as early as the fourth quarter of 2005.

Iso-Octane Conversion Project. As a result of environmental concerns related to MTBE, we are currently in the process of modifying our BEF facility to produce iso-octane, a motor gasoline octane enhancement additive derived from isobutane. We expect iso-octane 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 (including pending federal legislation) the facility may be further modified in the future to produce alkylate.

Petal Conversion Project. In the third quarter of 2004, we began to convert an existing brine well at our existing propane storage complex in Hattiesburg, Mississippi to natural gas service. This conversion, which is expected to cost $18 million, will create a new natural gas storage cavern with 1.8 Bcf of working gas capacity that will be integrated with our existing Petal natural gas storage facility. We expect to have the cavern in service during the second quarter of 2005. We have executed long-term storage agreements with BP for the entire capacity of the new natural gas storage cavern.

Purchase options associated with retained leases

EPCO contributed various equipment leases to us at our formation in 1998 for which EPCO has retained the cash payment obligations (the "retained leases"). EPCO has assigned to us the purchase options associated with the retained leases. During 2003, we exercised our option to purchase an isomerization unit and in October 2004 purchased the unit at a cost of $15 million, which approximated fair value. Additionally, in December 2004, we purchased equipment related to the isomerization unit for $2.8 million pursuant to our purchase option. Should we decide to exercise the remaining purchase options associated with the retained leases (which are also at fair value), an additional $2.3 million would be payable in 2008 and $3.1 million in 2016.

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

During 2004, we spent approximately $22.4 million to comply with these new regulations, of which $12.2 million was recorded as an operating expense of our NGL Pipelines & Services segment and $2.7 million was recorded as an operating expense of our Onshore Natural Gas Pipelines & Services segment. The remaining $7.5 million we spent to comply with the new regulations was capitalized. Based on information currently available, our cash outlays for our pipeline integrity program associated with these new regulations are estimated to be approximately $50.3 million for 2005.

The forecasted cost for 2005 is net of an indemnification we will receive from El Paso. In April 2002, GulfTerra acquired several midstream assets located in Texas and New Mexico from El Paso (the "EPN Holdings" acquisition). The assets acquired included the Texas Intrastate System, the Permian Basin System and the Indian Basin gas processing facility. Pursuant to an amended purchase and sale agreement between GulfTerra and El Paso for these assets, El Paso agreed to indemnify GulfTerra against all pipeline integrity costs incurred (whether paid or payable) with respect to the assets acquired in the EPN Holdings acquisition for each of the years ending December 31, 2005, 2006 and 2007, to the extent that such annual costs exceed $3.3 million; however, the amount reimbursable by El Paso for 2005, 2006 and 2007 shall not exceed $50.2 million.

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OUR CONTRACTUAL OBLIGATIONS

The following table summarizes our contractual obligations at December 31, 2004 (dollars in thousands):

Contractual Obligations	Total	Less than 1 year (2005)	1-3 years (2006 - 2007)	3-5 years (2008 - 2009)	More than 5 years Beyond 2009
	Payment or Settlement due by Period				
Scheduled maturities of long-term debt (1)	$4,288,698	$ 15,000	$ 500,000	$ 821,000	$2,952,698
Estimated cash payments for interest (2)	$2,666,248	$ 217,925	$ 413,253	$ 370,276	$1,664,794
Operating lease obligations (3)	$ 88,899	$ 15,012	$ 25,622	$ 14,914	$ 33,351
Purchase obligations: (4)					
Product purchase commitments: (5)					
Estimated payment obligations:					
Natural gas	$1,160,829	$ 165,120	$ 284,266	$ 284,655	$ 426,788
NGLs	$ 174,281	$ 42,664	$ 21,936	$ 21,936	$ 87,745
Petrochemicals	$1,791,983	$1,010,907	$ 774,828	$ 6,248	
Other	$ 166,706	$ 41,706	$ 62,271	$ 46,845	$ 15,884
Underlying major volume commitments:					
Natural gas (in BBtus)	149,705	21,855	36,500	36,550	54,800
NGLs (in MBbls)	5,657	1,267	732	732	2,926
Petrochemicals (in MBbls)	27,294	15,559	11,646	89	
Service payment commitments (6)	$ 7,580	$ 4,906	$ 2,674		
Capital expenditure commitment (7)	$ 69,288	$ 69,288			
Other long-term liabilities, as reflected on our Consolidated Balance Sheet (8)	$ 63,521		$ 15,846	$ 10,385	$ 37,290

(1) We have long and short-term payment obligations under credit agreements such as our senior notes and revolving credit facilities. Amounts shown in the table represent our scheduled future maturities of long-term debt principal (including current maturities) for the periods indicated. In accordance with SFAS No. 6, "*Classification of Short-Term Obligations Expected to Be Refinanced*," the scheduled maturities of debt presented in the table reflect (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 Credit Facility using proceeds from an equity offering completed in February 2005. For additional information regarding our debt obligations, please read "*Our liquidity and capital resources – Our debt obligation*" included within this Item 7 discussion.

(2) Amounts shown in the table above represent our estimated cash interest payments for long-term debt (including current maturities thereof) for the periods indicated.

(3) We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the table represent minimum lease payment obligations under our third-party operating leases with terms in excess of one year for the periods indicated. For addition information regarding our operating lease commitments, please read Note 16 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

(4) 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.

(5) 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. Amounts shown in the table represent 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, 2004 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery.

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

(7) 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 ordered.

(8) 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 table represent our best estimate as to the timing of payments based on available information.

The operating lease commitments shown in the preceding table exclude the non-cash, related party expense associated with various equipment leases contributed to us by EPCO at our formation for which EPCO has retained the liability (the “retained leases”). The retained leases are accounted for as operating leases by EPCO. EPCO’s minimum future rental payments under these leases are $2.1 million for each of the years 2005 through 2008, $0.7 million for each of the years 2009 through 2015 and $0.3 million for 2016. For additional information regarding the retained leases, please read Item 13 of this annual report on Form 10-K.

RECENT ACCOUNTING DEVELOPMENTS

FIN 46, “*Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51*.” This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity (“VIE”) with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 (as amended by FIN 46R) in 2003 has had no material effect on our consolidated financial statements. Due to the complexity of FIN 46 (as amended by FIN 46R and interpreted), the FASB is continuing to provide guidance regarding implementation issues. Since this guidance is still continuing, our conclusions regarding the application of this guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of FIN 46.

EITF 03-06, “*Participating Securities and the Two-Class Method under SFAS No. 128*.” This accounting guidance, which is applicable for the period beginning April 1, 2004, requires the two-class method for calculating earnings per share for certain securities that are considered to participate in earnings with common shareholders. Under the two-class method, distributions to equity owners are subtracted from earnings, and any remaining earnings would be allocated to the various classes of owners in proportion to their right to receive distributions as if those earnings had been distributed. The total distributions to each class of owner plus the amount allocated to each class would be used to compute earnings per unit for that class. Since our distributions to owners exceeded earnings during the periods presented, as has historically been the case, the two-class method did not produce any change from the way we have traditionally computed earnings per unit. As a result, our adoption of this standard had no effect on our earnings per unit calculations.

SFAS *No. 151, “Inventory Costs — an Amendment of ARB No. 43, Chapter 4.”* This accounting guidance, which is applicable for fiscal years beginning after June 15, 2005, amends ARB No. 43, Chapter 4, to clarify that abnormal amounts of idle facility expense, freight, handling costs and wasted materials (spoilage) should be recognized as current period charges. It also requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. We do not expect the adoption of SFAS No. 151 to have a material impact on our financial position, results of operations or cash flows.

SFAS No. 123(R), “Share-Based Payment.” This accounting guidance, which is applicable for the first interim or annual reporting period beginning after June 15, 2005, replaces SFAS No. 123, “*Accounting for Stock-Based Compensation*” and supersedes APB No. 25, “*Accounting for Stock Issued to Employees*.” This Statement eliminates the ability to account for share-based compensation transactions using APB No. 25, and generally requires instead that such transactions be accounted for using a fair-value-based method.

This statement requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with limited exceptions). That cost will be recognized over the period during which an employee is required to provide service in exchange for the award — the requisite service period (usually the vesting period). No compensation cost is recognized for equity instruments for which employees do not render the requisite service. Employee share purchase plans will not result in recognition of compensation cost if certain conditions are met; those conditions are much the same as the related conditions in SFAS No. 123.

A public entity will initially measure the cost of employee services received in exchange for an award of liability instruments based on its current fair value; the fair value of that award will be remeasured subsequently at each reporting date through the settlement date. Changes in fair value during the requisite service period will be recognized as compensation cost over that period.

The grant-date fair value of employee share options and similar instruments will be estimated using option-pricing models adjusted for the unique characteristics of those instruments (unless observable market prices for the same or similar instruments are available). If an equity award is modified after the grant date, incremental compensation cost will be recognized in an amount equal to the excess of the fair value of the modified award over the fair value of the original award immediately before the modification.

We are continuing to evaluate the provisions of SFAS No. 123(R) and will fully adopt the standard during 2005 within the prescribed time periods. Upon the required effective date, we will apply this statement using a modified version of prospective application as described in the standard.

OUR 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. We use the straight-line method to depreciate the majority of our property, plant and equipment, which results in depreciation expense being incurred evenly over the life of the assets. We estimate depreciation based on the estimated useful lives and residual values of our assets. As of the time we place our assets in service, we believe our estimates are accurate. However, circumstances in the future may develop which would cause us to change these estimates and in turn 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, 2004 and 2003, the net book value of our property, plant and equipment was $7.8 billion and $3 billion, respectively. We recorded $161 million and $101 million in depreciation expense during 2004 and 2003, respectively. A significant portion of the year-to-year increase in depreciation expense for 2004 and 2003 is attributable to the property, plant and equipment assets we acquired in the GulfTerra Merger, which were recorded at their preliminary fair values upon completion of the GulfTerra Merger at September 30, 2004. For additional information regarding our property, plant and equipment, please read Notes 1 and 6 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

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 margins and volumes; estimated useful life of the asset or asset group; and salvage values. An impairment charge would be recorded for the excess of the long-lived asset’s carrying value and its fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows but incorporating probabilities that reflect a range of possible outcomes and market value and replacement cost estimates.

Equity method investments are evaluated 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 include continued 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.

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 in income (loss) of unconsolidated affiliates on our 2003 Statement of Consolidated Operations. As a consolidated subsidiary, BEF continues to review its operations on quarterly basis due to the challenging and uncertain business environment in which it operates.

In order to complete the GulfTerra Merger, the FTC required us to sell our interest in a Mississippi propane storage facility in which we owned a 50% interest. As a result of our determination of this long-lived asset's current market value, we recorded a $4 million non-cash asset impairment charge during the third quarter of 2004, which is reflected as a component of operating costs and expenses on our 2004 Statement of Consolidated Operations.

Additionally, during 2003 we recorded a $1.2 million asset impairment charge related to our Petal NGL fractionator. This non-cash amount is a component of operating costs and expenses as shown on our 2003 Statement of Consolidated Operations. The Petal NGL fractionation facility was decommissioned in December 2003 after management decided that this older facility did not fit into our long-range plans due to poor economics of continued operations at the site. We continue to own this facility, the carrying value of which has been adjusted to its fair value of approximately $0.1 million.

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 approach to the valuation of 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 recorded intangible assets primarily include the estimated value assigned to certain customer relationships and contract-based assets.

Our customer relationship intangible assets represent the customer base that GulfTerra and the South Texas midstream assets serve through providing services, including natural gas gathering and processing, NGL fractionation and pipeline transportation. These entities conduct the majority of their business through the use of written contracts; thus, the customer relationships represent the rights we own arising from these contractual agreements. The value of these customer relationships are being amortized using expected production curves associated with the underlying resource bases (i.e., the oil and gas reserves associated with the intangible assets). Our estimate of the economic 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 contractual agreements in the natural gas and NGL storage operations. A contract-based intangible asset with a finite useful life is amortized over its estimated useful life, which is the period over which the asset is expected to contribute directly or indirectly to the future cash flows of an entity based on the respective contract terms. Our estimate of useful life is also based on a number of factors, including (1) the expected use of the asset by the entity, (2) the expected useful life of the related assets (i.e., fractionation facility, pipeline, etc.), (3) any legal, regulatory or contractual provisions, including renewal or extension periods that would cause substantial costs or modifications to existing agreements, (4) the effects of obsolescence, demand, competition, and other economic factors and (5) the level of maintenance required to obtain the expected future cash flows.

If our underlying assumptions regarding the useful life or the economic life of the resource base associated with an intangible asset change (either favorably or unfavorably), then we may be required to adjust the amortization period of such asset to reflect any new estimate of its useful life or economic life of the resource base. Such a change would increase or decrease the annual amortization charge associated with the asset at that time. 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 or economic life of the resource base associated with the asset. Any such write-down of the value and unfavorable change in the useful life or economic life associated with the resource base (i.e., amortization period) of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2004 and 2003, the carrying value of our intangible asset portfolio was $980.6 million and $268.9 million. We recorded $33.8 million and $14.8 million in amortization expense associated with our intangible assets during 2004 and 2003, respectively. A significant portion of the year-to-year increase in amortization expense for 2004 and 2003 is attributable to the intangible assets we acquired in the GulfTerra Merger, which were recorded at their preliminary fair values upon completion of the GulfTerra Merger at September 30, 2004. For additional information regarding our intangible assets, please read Notes 1 and 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Methods we employ to measure the fair value of goodwill

Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired and is primarily comprised of $376.8 million associated with the GulfTerra Merger which occurred on September 30, 2004, and $73.7 million associated with the purchase of propylene fractionation assets from Diamond-Koch in February 2002. Goodwill is not amortized. Instead, goodwill is tested for impairment at a reporting unit level annually, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. The testing of goodwill involves calculating the fair value of a reporting unit, which in turn is based on our assumptions regarding the future economic prospects of the reporting unit. If the fair value of the reporting unit (including related goodwill) is less than its book value, a charge to earnings would be required to reduce the carrying value of goodwill to its implied fair value. If our underlying assumptions regarding the future economic prospects of a reporting unit change, this could further impact the fair value of the reporting unit and result in an additional charge to earnings to reduce the carrying value of goodwill.

At December 31, 2004 and 2003, the carrying value of our goodwill was $459.2 million and $82.4 million. As a result of the GulfTerra Merger, the preliminary value allocated to goodwill is subject to change. For additional information regarding our goodwill, please read Notes 1 and 8 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 the contracts settle (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), a determination of the necessity of an allowance is made and recorded accordingly. Historically, the consolidated revenues we recorded were not materially based on estimates.

However, our use of estimates for revenues, as well as our use of estimates for operating costs and other expenses has increased as a result of SEC regulations which require us to submit financial information on increasingly 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 revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related information for the subject period). This accrual reverses in the following month and is offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, there is one month of 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 then extrapolated to the end 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 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 extensive federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations are applicable to each segment and require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. We currently have a reserve for environmental matters related to remediation costs expected to be incurred over time associated with mercury meters. We assumed this liability in connection with the GulfTerra Merger. New environmental developments, such as increasingly strict environmental laws and regulations and new claims for damages to property, employees, other persons and the environment resulting from current or past operations, could result in substantial cost and future liabilities. 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. Our actual results may differ from our estimates, and our estimates can be, and often are, revised in the future, either negatively or positively, depending upon the outcome or expectations based on the facts surrounding each exposure.

At December 31, 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 No. 5 "*Accounting for Contingencies*" and FASB Interpretation No. 14, "*Reasonable Estimation of the Amount of a Loss*," we recorded our best estimate of the loss.

Natural gas imbalances

Natural gas imbalances result when a customer delivers more or less gas into our pipelines than they take out. We generally value our imbalances using a twelve-month moving average of natural gas prices, which we believe is an appropriate assumption to estimate the value of the imbalances at the time of settlement given that the actual settlement dates are generally not known. Changes in natural gas prices may impact our estimates. Prior to the GulfTerra Merger, natural gas imbalances were not significant.

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

RELATED PARTY TRANSACTIONS

The following information highlights our relationships with EPCO, Shell and our unconsolidated affiliates. For additional information regarding our relationships with these entities, please read Item 13 of this annual report.

Relationship with EPCO

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise GP, our general partner. In addition, the executive and other officers of Enterprise GP are employees of EPCO, including Robert G. Phillips who is Chief Executive Officer and a director of Enterprise GP. For a listing of our directors and executive officers, please read Item 10 of this annual report.

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. In addition, at December 31, 2004, EPCO and Dan Duncan LLC, together, owned 90.1% of the membership interests of Enterprise GP, which in turn owns a 2% general partner interest in us. In January 2005, an affiliate of EPCO, Enterprise GP Holdings L.P., acquired El Paso's 9.9% membership interest in Enterprise GP. As a result of this transaction, EPCO and its affiliates own 100% of Enterprise GP. For additional information regarding this subsequent event, please read Note 21 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

In addition, trust affiliates of EPCO (the 1998 Trust and 2000 Trust), owned 11,387,615 of our common units at March 15, 2005. Collectively, Mr. Duncan, through his beneficial ownership of our common units held personally, by the 1998 and 2000 Trusts and through subsidiaries of EPCO, controlled approximately 37% of our common units at March 15, 2005. For additional information regarding the beneficial ownership of our common units, please read Item 12 of this annual report.

The principal business activity of Enterprise GP is to act as our managing partner. We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative and Services Agreement. We reimburse EPCO for the costs associated with employees who work on our behalf. We have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLs and other products. In addition, we sell NGL products to EPCO's Canadian affiliate. During 2004, our related party revenues from EPCO were $2.7 million and our related party expenses with EPCO were $230.7 million.

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At March 15, 2005, Shell owned approximately 9.5% of our common units. Shell is one of our largest customers. For the years ended December 31, 2004, 2003 and 2002, Shell accounted for 6.5%, 5.5% and 7.9%, 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. During 2004, our related party revenues from Shell were $542.9 million and our related party expenses with Shell were $725.4 million.

The most significant contract affecting our natural gas processing business is the Shell margin-band/keepwhole processing agreement, which grants us the right to process Shell's current and future production within state and federal waters of the Gulf of Mexico. We have also completed a number of business acquisitions and asset purchases involving Shell since 1999. For additional information regarding our relationship with Shell, please read Item 13 of this annual report.

Relationships with unconsolidated affiliates

Our investment in unconsolidated affiliates with industry partners is a vital component of our business strategy. These investments are a means by which we conduct our operations to align our interests with a supplier of raw materials or a consumer 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. During 2004, related party revenues from our unconsolidated affiliates were $258.5 million and related party expenses with the unconsolidated affiliates were $37.6 million.

On occasion, we enter into management agreements with some of our unconsolidated affiliates under which our unconsolidated affiliates pay us management fees for the operation and management of their assets. However, these fees are not material to our consolidated results of operations. Additionally, on occasion we pay for construction costs on behalf of our unconsolidated affiliates during the initial construction phase of their assets, and these amounts are settled by direct reimbursements for the amounts we are owed from our unconsolidated affiliates.

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 (as shown on our Statements of Consolidated Operations and Comprehensive Income included under Item 8 of this annual report) follows:

	Year Ended December 31,		
	2004	2003	2002
Total non-GAAP gross operating margin	$ 655,191	$ 410,415	$ 332,349
Adjustments to reconcile total non-GAAP gross operating margin to GAAP operating income:			
Depreciation and amortization in operating costs and expenses	(193,734)	(115,643)	(86,028)
Retained lease expense, net in operating costs and expenses	(7,705)	(9,094)	(9,125)
Gain on sale of assets in operating costs and expenses	15,901	16	1
Selling, general and administrative costs	(46,659)	(37,590)	(42,890)
GAAP consolidated operating income	422,994	248,104	194,307
Other expense	(153,625)	(134,406)	(94,226)
GAAP income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 269,369	$ 113,698	$ 100,081

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year. These subleases (the “retained lease expense” in the previous table) are part of the Administrative Services Agreement that we executed with EPCO in connection with our formation in 1998. EPCO holds these items pursuant to operating leases for which it has retained the corresponding cash lease payment obligation.

Operating costs and expenses (as shown on the Statements of Consolidated Operations and Comprehensive Income included under Item 8 of this annual report) treat the lease payments being made by EPCO as a non-cash related party operating expense, with the offset to Partners’ Equity on the Consolidated Balance Sheets recorded as a general contribution to the Company. 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 EPCO Administrative Services Agreement and the retained leases, please read Item 13 of this annual report.

Cumulative effect of changes in accounting principles. As shown on our Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2004, the cumulative effect of changes in accounting principles represents the combined impact of (1) 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 (2) changing the method in which we account for our investment in VESCO from the cost method to the equity method.

Our BEF subsidiary 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. BEF used the accrue-in-advance method to record cost estimates for such activities; whereas, the Company’s other operations used the expense-as-incurred method for their planned major maintenance activities. Our BEF subsidiary changed its accounting method on January 1, 2004 to conform to the Company’s accounting for planned major maintenance costs, which better reflects expenses in the period incurred. As such, we believe the change is to a method that is preferable in the circumstances. The cumulative effect of this accounting change for years prior to 2004 resulted in a benefit of $7 million.

EITF 03-16, “*Accounting for Investments in Limited Liability Companies*,” requires investments in limited liability companies that have separate ownership accounts for each investor be accounted for similar to limited partnerships under SOP No. 78-9, “*Accounting for Investments in Real Estate Ventures*.” Under this new guidance (applicable for the period beginning July 1, 2004), 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 3-5%) than the traditional 20% threshold applied under APB Opinion No. 18, "*The Equity Method of Accounting for Investments in Common Stock*."

Prior to July 1, 2004, 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 that we received cash distributions from them. In accordance with the new accounting guidance in EITF 03-16, we recorded a cumulative effect adjustment equal to the difference between (i) equity earnings from VESCO that would have been recorded using the equity method in periods prior to July 1, 2004 and (ii) the dividend income from VESCO we recorded using the cost method in prior periods. The cumulative effect of this accounting change resulted in a benefit of $3.8 million.

For the periods indicated, the following table shows pro forma net income and earnings per unit amounts assuming the accounting changes noted above were applied retroactively to January 1, 2002. See Note 13 for information regarding the effect of the accounting changes on basic and diluted earnings per unit.

	For the Year Ended December 31,		
	2004	2003	2002
Pro Forma income statement amounts:			
Historical net income	$ 268,261	$ 104,546	$ 95,500
Adjustments to derive pro forma net income:			
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	(8,569)
Record equity in (income) losses from BEF calculated using new method of accounting for major maintenance costs		(31,800)	8,980
Remove cumulative effect of change in accounting principle recorded on January 1, 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 on July 1, 2004	(3,768)		
Remove historical dividend income recorded from VESCO	(2,136)	(5,595)	(4,737)
Record equity earnings from VESCO	2,429	5,133	12,303
Pro forma net income	260,111	103,792	103,477
Enterprise GP interest	(36,945)	(20,708)	(10,743)
Pro forma net income available to limited partners	$ 223,166	$ 83,084	$ 92,734
Pro forma per unit data (basic):			
Historical units outstanding	265,511	199,915	155,454
Per unit data:			
As reported	$ 0.87	$ 0.42	$ 0.55
Pro forma	$ 0.84	$ 0.42	$ 0.60
Pro forma per unit data (diluted):			
Historical units outstanding	266,045	206,367	176,490
Per unit data:			
As reported	$ 0.87	$ 0.41	$ 0.48
Pro forma	$ 0.84	$ 0.40	$ 0.53

RISK FACTORS

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

Among the key risk factors that may have a direct impact on our results of operations 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. In general terms, 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 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 also exposed to natural gas and NGL commodity price risk under natural gas processing and gathering and NGL fractionation contracts that provide for our fee 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 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 out of our control and can adversely affect the decision by producers to explore for and develop new reserves. These factors include relatively low oil and natural gas prices, cost and availability of equipment, regulatory changes, capital budget limitations or the lack of available capital. 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 reduction 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 reduction 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 the combined company transports.

Isobutane. Any 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. Any 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 debt level may limit our future financial and operating flexibility.

As of December 31, 2004, we had approximately $4.3 billion of consolidated debt outstanding. The amount of our debt could have significant effects on our future operations, including, among other things:

- a significant portion of our cash flow from operations will be dedicated to the payment of principal and interest on outstanding debt and will 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. Our multi-year revolving credit facility, however, restricts our ability to incur additional debt, though any debt we may incur in compliance with these restrictions may still be substantial.

Our multi-year revolving credit facility and indentures for our public debt contain conventional financial covenants and other restrictions. A breach of any of these restrictions by us could permit the lenders to declare all amounts outstanding under those debt agreements to be immediately due and payable and, in the case of the credit facilities, to terminate all commitments to extend further credit.

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 adverse market conditions resulting from, among other things, general economic conditions, contingencies and uncertainties that are difficult to predict and impossible to control. Moreover, if the rating agencies were to downgrade our partnership’s credit rating, 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 qualified assets.

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 diversify our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating, 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 may require substantial new capital to finance the future development and acquisition of assets and businesses. Limitations on our access to capital will impair our ability to execute this strategy. Expensive capital will limit our ability to develop or acquire accretive assets. We may not be able to raise the necessary funds on satisfactory terms, if at all.

In addition, we are experiencing increased competition for the assets we purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in our losing to other bidders more often or acquiring assets at higher prices. Either occurrence would limit our ability to fully execute our growth strategy. Our inability to execute our growth strategy may materially adversely impact the market price of our securities.

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. Similar to the risks associated with integrating our operations with GulfTerra's 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 business.

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 expended, and our operating cash flow from a particular project may not increase immediately following 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 after it is placed in service. If we experience unanticipated or extended delays in generating operating cash flow from these projects, we may be required to reduce or reprioritize our capital budget, sell non-core assets, access the capital markets or decrease 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, construction or other acquisition of energy infrastructure assets, including some construction and development projects with significant technological challenges. For example, underwater operations, especially those in water depths in excess of 600 feet, are very expensive and involve much more uncertainty and risk, and if a problem occurs, the solution, if one exists, may be very expensive and time consuming. We may not be able to complete our projects, whether in deepwater or otherwise, at the costs estimated at the time of initiation.

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 joint ventures, each participant in each of these joint ventures has made substantial investments in the joint venture and, accordingly, has required that the relevant organizational 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 in that joint venture, 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 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 our partnering with different or additional parties.

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

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 unitholders.

In addition, our joint venture charter documents typically vest in its management committee's sole discretion regarding the occurrence and amount of distributions. Some of the joint ventures in which we participate have several 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 or at all.

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.

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 fees generated by our energy infrastructure assets, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available from operating activities and, accordingly, adversely affect the market price of our securities.

We believe that we maintain adequate insurance coverage, 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, we may not be able to renew our existing insurance policies 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, 2004 our balance sheet reflected $459.2 million of goodwill and $980.6 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. GAAP requires 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 adversely affect our business.

In addition to our exposure to commodity prices, we have significant exposure to increases in interest rates. As of December 31, 2004, we had approximately $4.3 billion of consolidated debt, of which approximately $2.9 billion was at fixed interest rates and approximately $1.4 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.

In December 2003, the U.S. Department of Transportation issued a final rule (effective as of February 14, 2004) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers 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 outcome of this rule on us. However, we will continue our pipeline integrity testing programs, which are intended 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 cash flow.

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. Moreover, as with other companies engaged in similar or related businesses, our operations have some risk of environmental costs and liabilities because we handle petroleum products.

Federal, state or local regulatory measures could materially adversely affect our business.

The Federal Energy Regulatory Commission, or FERC, regulates our interstate natural gas pipelines and interstate NGL and petrochemical pipelines and interstate natural gas storage facilities, while state regulatory agencies regulate our intrastate natural gas and NGL pipelines, intrastate storage facilities and gathering lines. This federal and state regulation extends to such matters as:

- rate structures;
- rates of return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction and disposition of assets; and
- to an extent, the level of competition in that regulated industry

For a general overview of FERC and state regulation applicable to our energy infrastructure assets, please read "*Business and Properties — Regulation and Environmental Matters*", included under Items 1 and 2 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 flow.

Under the Natural Gas Act, FERC has authority to regulate our natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services includes the rates charged for the services, terms and conditions of service, 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 services, and various other matters. 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 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.

For example, in December 2002, High Island Offshore System ("HIOS'), an interstate natural gas pipeline owned by us, filed a rate case pursuant to Section 4 of the Natural Gas Act before FERC to increase its transportation fees. FERC accepted HIOS' tariff sheets implementing the new rates, subject to refund, and set certain issues for hearing before an Administrative Law Judge ("ALJ") The ALJ issued an initial decision on the issues set for hearing on April 22, 2004, proposing rates lower than the rate initially proposed by HIOS. In response to the ALJ's initial decision, HIOS filed, on August 5, 2004, a settlement agreement whereby HIOS proposed to implement its rates in effect prior to this proceeding for a prospective three-year period.

On January 24, 2005, FERC issued an order rejecting HIOS' settlement offer and generally affirming the ALJ's initial decision, resulting in rates significantly lower than the rate proposed in HIOS' settlement offer. On February 24, 2005, we filed a request for rehearing with the FERC. FERC's January 24 order may be subject to other requests for rehearing and appeal to federal court. We are not able to predict the outcome of the HIOS proceeding, but an adverse outcome in this proceeding or any other rate case proceedings to which we may be a party in the future could adversely affect our results of operations, cash flows and financial position.

FERC also has authority under the Interstate Commerce Act, or ICA, to regulate the rates, terms, and conditions applied to our interstate pipelines engaged in the transportation of NGLs and petrochemicals (commonly known as "oil pipelines"). Pursuant to the ICA, oil pipeline rates can be challenged at FERC either by protest, when they are initially filed or increased, or by complaint at any time they remain on file with the jurisdictional agency.

We have interests in natural gas pipeline facilities offshore from Texas and Louisiana. These facilities are subject to regulation by 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 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, or NGPA. We also have natural gas underground storage facilities in Louisiana, Mississippi and Texas. Although state regulation is typically less onerous than at 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.

On July 20, 2004, the United States Court of Appeals for the District of Columbia Circuit issued its opinion in *BP West Coast Products, LLC v. FERC*, addressing the rate of SFPP, a publicly traded limited partnership. The Court a) upheld FERC's determination that some of SFPP's rates were grandfathered rates under the Energy Policy Act and that SFPP's shippers had not demonstrated substantially changed circumstances that would justify modification of those rates, remanded the issue b) eliminated the tax allowance in SFPP's rates because the SFPP limited partnership did not have tax liability and c) remanded the issue of whether SFPP's revised cost of service without the tax allowance would qualify as a substantially changed circumstance that would justify modification of SFPP's rates. Because the court remanded the case to the FERC and because the FERC's ruling on the substantially changed circumstances issue will focus on the facts and record presented to it, it is not clear what impact, if any, the opinion will have on our rates or on the rates of other FERC-jurisdictional pipelines organized as tax pass-through entities. FERC has initiated a public inquiry in Docket No. PL05-5 into the proper treatment of income tax allowances on cost-of-service ratemaking proceeding involving partnerships. Moreover, it is not clear whether FERC's action taken in response to *BP West Coast* will be challenged and, if so, whether it will withstand further FERC or judicial review.

Parties could challenge the rates of our common carrier interstate liquid pipelines and our interstate natural gas pipelines and argue that the rationale in the BP West Coast decision, regarding tax allowances, should be applied. While it is possible that party might challenge these rates, it is not possible to predict the likelihood that such a challenge would succeed at the FERC.

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

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. An escalation of political tensions in the Middle East and elsewhere, could result in increased volatility in the world's energy markets and result in a material adverse effect on our business.

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.

Following the GulfTerra Merger and 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 its issuance of equity securities ranking equal or junior to the common units. The issuance of additional common units or other equity securities of equal 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 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 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 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 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 Enterprise 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 GP and its affiliates, including officers and directors of Enterprise 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 GP has sole discretion to determine the amount of these expenses. In addition, Enterprise GP and its affiliates may provide other services to us for which we will be charged fees as determined by Enterprise GP.

Enterprise GP and its affiliates have limited fiduciary responsibilities and conflicts of interest with respect to our partnership.

The directors and officers of Enterprise GP and its affiliates have duties to manage Enterprise GP in a manner that is beneficial to its members. At the same time, Enterprise GP has duties to manage our partnership in a manner that is beneficial to us. Therefore, Enterprise 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:

- decisions of Enterprise 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 GP;
- under our partnership agreement, Enterprise GP determines which costs incurred by it and its affiliates are reimbursable by us;
- Enterprise GP is allowed to take into account the interests of parties other than us, such as its parent company, EPCO, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to unitholders;
- affiliates of Enterprise GP may compete with us in certain circumstances;
- Enterprise GP may limit our liability and reduce our fiduciary duties, while also restricting 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; and
- we do not have any employees and we rely solely on employees of EPCO and its affiliates.

Even if unitholders are dissatisfied, they cannot easily remove Enterprise 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 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 will have little ability to remove Enterprise GP. Enterprise GP may not be removed except upon the vote of the holders of at least 64% of our outstanding units voting together as a single class. Because affiliates of Enterprise GP currently own approximately 37% of our outstanding common units, the removal of Enterprise GP as our general partner is not possible without the consent of both Enterprise GP and such owner 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 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 GP and its affiliates own 85% or more of the common units then outstanding, Enterprise 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 their 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. Under our partnership agreement, Shell is not deemed to be an affiliate of Enterprise GP for purposes of this limited call right.

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.

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 March 15, 2005, a total of approximately 383,554,318 million of our common units were outstanding. Shell owns 36,572,122 of our common units, representing approximately 9.5% of our outstanding common units at March 15, 2005, 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. Under a registration rights agreement, we are obligated, subject to certain limitations and conditions, to register the common units held by Shell for resale.

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.

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.

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 No. 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.

Due to the complexity of SFAS No. 133 (as amended and interpreted), the FASB is continuing to provide guidance regarding the implementation of this accounting standard. Since this guidance is still continuing, our conclusions about the application of SFAS No. 133 may be altered, which may result in adjustments being recorded in future periods as we adopt new FASB interpretations of this standard.

Interest rate risk hedging program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess the 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 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 climate.

Fair value hedges – Interest rate swaps. In January 2004, we entered into three interest rate swap agreements with an aggregate notional amount of $250 million in which we exchanged the payment of fixed rate interest on a portion of principal outstanding under Senior Notes B and C for variable rate interest. During the fourth quarter of 2004, we entered into six additional interest rate swap agreements with an aggregate notional amount of $600 million related to a portion of the principal outstanding under Senior Notes G issued on October 4, 2004.

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 6.3%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 4.9%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 3.4%	$600 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these nine interest rate swaps as fair value hedges under SFAS No. 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 fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

These nine agreements have a combined notional amount of $850 million 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 LIBOR rates (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.

Total fair value of the interest rate swaps in effect at December 31, 2004 was a receivable of approximately $0.5 million with an offsetting increase in fair value of the underlying debt. Interest expense in our Statements of Consolidated Operations and Comprehensive Income for the year ended December 31, 2004 reflects a $9.1 million benefit from these swap agreements.

The following tables show the effect of hypothetical price movements on the estimated fair value (“FV”) of our interest rate swap portfolio and the related change in fair value of the underlying debt at the dates indicated (dollars in thousands):

Scenario	Resulting Classification	Swap FV at 12/31/04	Inc (Dec) in FV of Debt
FV assuming no change in underlying interest rates	*Asset (Liability)*	$ 505	$ (505)
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(31,586)	32,091
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	32,596	(32,091)

Scenario	Resulting Classification	Swap FV at 03/02/05	Inc (Dec) in FV of Debt
FV assuming no change in underlying interest rates	*Asset (Liability)*	$ (10,066)	$ 10,066
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(42,028)	31,963
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	21,897	(31,963)

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, 2004 and March 2, 2005 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 March 2, 2005 fair values ranged from approximately 2.2% to 5.5% using 6-month reset periods ranging from October 2004 to October 2014.

Cash flow hedges – Forward starting interest rate swaps. During the first nine months of 2004, we entered into eight forward starting interest rate swap transactions having an aggregate notional amount of $2 billion in anticipation of our financing activities associated with closing the GulfTerra Merger. Our purpose in entering into these transactions was to effectively hedge the underlying U.S. treasury rate related to our anticipated issuance of $2 billion in principal amount of fixed rate debt. On October 4, 2004, our Operating Partnership issued $2 billion of private debt securities under Senior Notes E, F, G and H. Each of the forward starting swaps was designated as a cash flow hedge under SFAS No. 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 net gain of $19.4 million from these settlements will be reclassified from Accumulated Other Comprehensive Income to reduce interest expense over the life of the associated debt.

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

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

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 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 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.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis performed on this portfolio measures the potential income or loss (e.g., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the dates noted within the following table. In general, the quoted market prices used in the model are from those actively quoted on commodity exchanges (i.e., NYMEX) for instruments of similar duration. In those rare instances where prices are not actively quoted, we calculate forward price curves based on similar products which are actively quoted using regression equations with strong correlation factors.

The sensitivity analysis model takes into account the following primary factors and assumptions:

- the current quoted market price of natural gas;
- the current quoted market price of NGLs;

- changes in the composition of commodities hedged (i.e., the mix between natural gas and related NGLs);
- fluctuations in the overall volume of commodities hedged (for both natural gas and related NGL hedges outstanding);
- market interest rates, which are used in determining the present value; and
- a liquid market for such financial instruments.

An increase in fair value of the commodity financial instruments (based upon the factors and assumptions noted above) approximates the income that would be recognized if all of the commodity financial instruments were settled at the dates noted within the table. Conversely, a decrease in fair value of the commodity financial instruments would result in the recording of a loss.

The sensitivity analysis model does not include the impact that the same hypothetical price movement would have on the hedged commodity positions to which they relate. Therefore, the impact on the fair value of the commodity financial instruments of a change in commodity prices would be offset by a corresponding gain or loss on the hedged commodity positions, assuming:

- the commodity financial instruments function effectively as hedges of the underlying risk;
- the commodity financial instruments are not closed out in advance of their expected term; and
- as applicable, anticipated underlying transactions settle as expected.

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 commodity financial instrument to reestablish the economic hedge to which the closed instrument relates.

We had a limited number of commodity financial instruments in our portfolio at December 31, 2004. The following tables show the effect of hypothetical price movements on the estimated fair value ("FV") of this portfolio at the dates indicated (dollars in thousands):

Scenario	Resulting Classification	FV at 12/31/03	FV at 12/31/04	FV at 3/02/05
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 4	$ 219	$ (256)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	4	47	(703)
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	4	391	191

At December 31, 2004, our portfolio primarily consisted of a limited number of natural gas cash flow and fair value hedges. We recorded $0.4 million of income related to our commodity hedging activities during 2004 and an expense of $0.6 million during 2003 that are included in our operating costs and expenses in the Statements of Consolidated Operations and Comprehensive Income.

During 2002, we recognized a loss of $51.3 million from our commodity hedging activities that was recorded as an increase in our operating costs and expenses. Beginning in late 2000 and extending through March 2002, a large number of our commodity hedging transactions were based on the historical relationship between natural gas and NGL prices. This type of hedging strategy utilized the forward sale of natural gas at a fixed price with the expected margin on the settlement of the position offsetting or mitigating changes in the anticipated margins on NGL marketing activities and the market values of our equity NGL production. Throughout 2001, this strategy proved very successful (as the price of natural gas declined relative to our fixed positions) and was responsible for most of the $101.3 million in commodity hedging income we recorded during 2001.

In late March 2002, the effectiveness of this strategy was reduced due to an unexpected rapid increase in natural gas prices whereby the loss in the value of our fixed-price natural gas financial instruments was not offset by increased natural gas processing margins. Due to the inherent uncertainty surrounding natural gas prices at the time, we decided that it was prudent to exit this strategy, and we did so by late April 2002. The increased ineffectiveness of this strategy is the primary reason for the $51.3 million in commodity hedging losses recorded during 2002.

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 "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Our Contractual Obligations*" included under Item 7 of this annual report.

Effect of financial instruments on Accumulated Other Comprehensive Income (Loss)

The following table summarizes the effect of our cash flow hedging financial instruments on accumulated other comprehensive income (loss) since January 1, 2002.

	Commodity Financial Instruments	Interest Rate Fin. Instrs.		Accumulated Other Comprehensive Income (Loss) Balance
		Treasury Locks	Forward-Starting Interest Rate Swaps	
Balance, January 1, 2002		$ —		$ —
Change in fair value of treasury locks		(3,560)		(3,560)
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 treasury locks to interest expense		(418)		(418)
Reclassification of gain on settlement of forward-starting swaps to interest expense			(857)	(857)
Balance, December 31, 2004	$ 1,434	$ 4,572	$ 18,548	$ 24,554

During 2005, we will reclassify $0.4 million and $3.6 million from Accumulated Other Comprehensive Income as a reduction in interest expense from our treasury locks and forward-starting interest rate swaps, respectively. In addition, in the first quarter of 2005, we will record an approximate $1.6 million gain into income from Accumulated Other Comprehensive Income related to a commodity cash flow hedge acquired in the GulfTerra Merger. This gain is primarily due to an increase in fair value from that recorded for the commodity cash flow hedge at December 31, 2004.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The information required hereunder is included in this annual report on Form 10-K as set forth in the "*Index to Financial Statements and Supplemental Schedule*" beginning on page F-1.

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, with the participation of the CEO and CFO of Enterprise GP, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2004. 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 Enterprise GP, 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 the Company 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 also is 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 assurances of achieving our desired control objectives, and our CEO and CFO have concluded, as of December 31, 2004, that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

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 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 100.

Changes in internal control over financial reporting during the fourth quarter of 2004. Other than the events discussed under "Internal Controls Over Financial Reporting and the GulfTerra Merger Transactions" below, there have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) or in other factors that occurred during the fiscal quarter ended December 31, 2004, that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Internal Controls Over Financial Reporting and the GulfTerra Merger and Related Transactions

On September 30, 2004, we completed the GulfTerra Merger and related transactions, which met the criteria of being a significant acquisition for us. For additional information regarding the GulfTerra Merger, please read "Recent Developments" under Item 1 of this annual report. At December 31, 2004, GulfTerra and the related South Texas midstream assets represented approximately 54% of our total consolidated assets. In addition, these operations accounted for 7% of our consolidated revenues for the year ended December 31, 2004.

On June 22, 2004, the Office of the Chief Accountant of the SEC issued guidance regarding the reporting of internal controls over financial reporting in connection with a major acquisition. On October 6, 2004, the SEC revised its guidance to include expectations of quarterly reporting updates of new internal controls and the status of the controls regarding any exempted businesses.

On October 18, 2004, the Disclosure Committee of Enterprise GP met and voted to recommend the exclusion of GulfTerra and the South Texas midstream assets from the scope of Enterprise's Sarbanes-Oxley Section 404 report on internal controls over financial reporting for the year ended December 31, 2004. A summary of the reasons for exclusion follow:

- Prior to completion of the GulfTerra Merger, we were required to comply with FTC guidelines regarding the sharing of information between us and GulfTerra. This severely limited our ability to conduct a timely and specific due diligence review of GulfTerra's existing internal control framework. Given the time required to test the operating effectiveness of such controls and the due date for the Section 404 attestation, it was not practical from a timing or resource standpoint for us to conduct a thorough assessment prior to year end 2004.

- GulfTerra and the South Texas midstream assets utilized a financial accounting (i.e. a general ledger) computer system that is different from that used by us. For practicality reasons, GulfTerra and the South Texas midstream assets remained on these systems (which were on a computer network owned by El Paso) through the December 31, 2004. We converted these financial accounting computer systems to ours in January 2005. As a result, we believe that reporting on the controls of the current computer system used by GulfTerra and the South Texas midstream assets during 2004 would not be useful to our investors since these systems were discontinued on December 31, 2004. In addition, we believe that obtaining an independent review of such computer systems and controls at El Paso would not have been feasible.

- Enterprise is in the process of implementing its internal control structure over the operations of GulfTerra and the South Texas midstream assets. Due to the magnitude of the businesses, we expect that this effort will be completed in late 2005. The assessment and documentation of internal controls requires a complete implementation of controls operating in a stable and effective environment.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2004

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries (the "Company"), 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 the Company's management and board of directors regarding the preparation and fair presentation of published financial statements. However, our management does not expect 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 absolute, assurance that the objectives of the control system are met.

Our management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. 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, 2004, the Company's internal control over financial reporting is effective based on those criteria excluding the acquired businesses from GulfTerra Energy Partners, L.P. and the South Texas midstream assets acquired from El Paso Corporation and its affiliates. Those businesses and assets were acquired on September 30, 2004 and the associated financial statements reflect total assets and revenues constituting approximately 54% and 7%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2004. An explanation of this exclusion and the reasons for excluding the above mentioned acquired businesses and South Texas midstream assets are provided in item 9A of this report.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 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 the Company. 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 the Company's 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 the Company's 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 March 15, 2005.

	/s/ Robert G. Phillips		/s/ Michael A. Creel
Name:	Robert G. Phillips	Name:	Michael A. Creel
Title:	Principal Executive Officer of our general partner, Enterprise GP	Title:	Principal Financial Officer of our general partner, Enterprise GP

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 subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, management excluded from their assessment the internal control over financial reporting of GulfTerra Energy Partners L.P. and subsidiaries ("GulfTerra") and the South Texas midstream assets which were acquired from El Paso Corporation, (collectively referred to as the "South Texas Midstream Assets"), which were both acquired on September 30, 2004 and whose financial statements reflect total assets and revenues constituting approximately 54% and 7%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2004. Accordingly, our audit did not include the internal control over financial reporting for GulfTerra and the South Texas Midstream Assets. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM (Continued)

financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets, the related statements of consolidated operations and comprehensive income, consolidated cash flows, consolidated partners' equity and the consolidated financial statement schedule as of and for the year ended December 31, 2004 of the Company and our report dated March 15, 2005 expressed an unqualified opinion on those financial statements and the financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 15, 2005

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 the Administrative Services Agreement under the direction of the Board of Directors and executive officers of Enterprise GP, our general partner. For a description of the Administrative Services Agreement, please read "*Certain Relationships and Related Transactions*" under Item 13 of this annual report.

Because we are a limited partnership and are totally controlled by Enterprise GP, we meet the definition of a "controlled company" under the listing standards of the NYSE. Accordingly, 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 GP maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Notwithstanding any contractual limitation on its obligations or duties, Enterprise 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 GP. Whenever possible, Enterprise GP intends to make any such indebtedness or other obligations non-recourse to itself.

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. Enterprise GP is committed to having at least a majority of its Board of Directors be independent 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 GP or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with Enterprise GP or us). Based on the foregoing, the Board has affirmatively determined that Dr. Ralph S. Cunningham, Lee W. Marshall, Sr., W. Matt Ralls and Richard S. Snell are "independent" directors under the NYSE rules. Thus, the Board of Directors of Enterprise has a majority (57%) of independent directors.

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 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 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 both Dr. Ralph S. Cunningham and W. Matt Ralls satisfy the definition of "audit committee financial expert."

Executive Sessions of Board. The Board of Directors of Enterprise 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 Dr. Ralph S. Cunningham, 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 GP as a group. All calls to this Hotline are reported to the Chairman of the Audit and Conflicts Committee of Enterprise 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 GP has two committees: the Audit and Conflicts Committee and the Governance Committee. For additional information regarding these committees, please read the information beginning on page 108.

Governance Guidelines. Governance guidelines, together with committee charters, provide the framework for effective governance. The Board of Directors of Enterprise GP has adopted the Enterprise Products Partners L.P. Governance Guidelines addressing 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 GP recognizes that effective governance is an on-going process, and thus, the Board will review the Enterprise Products Partners L.P. Governance Guidelines annually or more often as deemed necessary.

Code of Conduct. We have 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. We have 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 Enterprise Products Partners L.P. Governance Guidelines and other matters impacting our governance principles. You may also contact our investor relations department at (713) 880-6500 for printed copies of these documents free of charge.

Directors and Executive Officers of Enterprise GP

Set forth below is the name, age and position of each of the directors and executive officers of Enterprise GP at March 1, 2005. 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.

Name	Age	Position with Enterprise GP
Dan L. Duncan(1)	72	Director and Chairman of the Board
O.S. Andras(1)	69	Director and Vice Chairman of the Board
Robert G. Phillips(1)	50	Director, President and Chief Executive Officer
Richard H. Bachmann(1)	52	Executive Vice President, Chief Legal Officer and Secretary
Michael A. Creel(1)	51	Executive Vice President and Chief Financial Officer
James H. Lytal(1)	47	Executive Vice President
A.J. Teague(1)	59	Executive Vice President
Charles E. Crain(1)	71	Senior Vice President
W. Ordemann(1)	45	Senior Vice President
Gil H. Radtke(1)	44	Senior Vice President
James M. Collingsworth (1)	50	Senior Vice President
James A. Cisarik(1)	46	Senior Vice President
Lynn L. Bourdon, III(1)	43	Senior Vice President
Bart H. Heijermans(1)	38	Senior Vice President
Richard A. Hoover(1)	48	Senior Vice President
Joel D. Moxley(1)	47	Senior Vice President
Michael J. Knesek(1)	50	Senior Vice President, Controller and Principal Accounting Officer
W. Randall Fowler(1)	48	Senior Vice President and Treasurer
Dr. Ralph S. Cunningham(2,3)	64	Director
Lee W. Marshall, Sr. (2)	72	Director
W. Matt Ralls(2,3)	55	Director
Richard S. Snell(3)	62	Director

(1) Executive officer

(2) Member of Audit and Conflicts Committee

(3) Member of Governance Committee

Some of the executive officers of Enterprise GP spend portions of their time managing the business and affairs of EPCO and its affiliates. In general, Enterprise GP directs its officers to devote as much time as is necessary for the proper conduct of our business and affairs in the event that these officers face conflicts regarding the allocation of their time between our business and the business interests of EPCO and its other affiliates. Unless otherwise indicated below, each officer devotes 100% of his time to our business and affairs.

Dan L. Duncan was elected Chairman and a Director of Enterprise GP in April 1998. Mr. Duncan has served as Chairman of the Board of our predecessor, EPCO, since 1979. Mr. Duncan devotes approximately 40% of his time to our business and affairs.

O.S. Andras has served in his current position since February 11, 2005, prior to which he had been Chief Executive Officer, Vice Chairman and a Director of Enterprise GP from September 30, 2004 to February 11, 2005. Mr. Andras served as President, Chief Executive Officer and a Director of Enterprise GP from April 1998 until September 30, 2004. Mr. Andras served as President and Chief Executive Officer of EPCO from 1996 to February 2001 and currently serves as Vice Chairman of the Board of EPCO. Mr. Andras devotes approximately 60% of his time to our business and affairs.

Robert G. Phillips has served in his current position since February 11, 2005. He served as President, Chief Operating Officer and a Director of Enterprise GP beginning on September 30, 2004, which was the date of completion of the GulfTerra Merger. We had agreed to elect Mr. Phillips to those positions in connection with negotiating the merger agreement with GulfTerra. Mr. Phillips served as a Director of GulfTerra's general partner from August 1998 until September 2004. In addition, he served as Chief Executive Officer for GulfTerra and its general partner from November 1999 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 between June 1997 and 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 thereto, Mr. Phillips was Chief Executive Officer of Eastex Energy, Inc.

Richard H. Bachmann was elected Executive Vice President, Chief Legal Officer and Secretary of Enterprise GP and EPCO in January 1999. Mr. Bachmann served as a Director of Enterprise GP from June 2000 to January 2004. Mr. Bachmann devotes approximately 60% of his time to our business and affairs.

Michael A. Creel was elected an Executive Vice President of Enterprise GP and EPCO in February 2001, having served as a Senior Vice President of Enterprise GP and EPCO since November 1999. In June 2000, Mr. Creel, a certified public accountant, assumed the role of Chief Financial Officer of Enterprise GP and EPCO along with his other responsibilities. Mr. Creel devotes approximately 60% of his time to our business and affairs.

James H Lytal was elected Executive Vice President of Enterprise GP in September 2004. Mr. Lytal served as a Director of GulfTerra's general partner from August 1994 until September 2004, and as GulfTerra's President and President of GulfTerra's 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 in the oil and gas exploration and production and gas pipeline industries with Untied Gas Pipeline Company, Texas Oil and Gas, Inc. and American Pipeline.

A.J. Teague was elected an Executive Vice President of Enterprise GP in November 1999. From 1998 to 1999 he served as President of Tejas Natural Gas Liquids, LLC, then a Shell affiliate.

Charles E. Crain was elected a Senior Vice President of Enterprise GP in April 1998. Mr. Crain served as Senior Vice President of Operations for EPCO from 1991 to 1998.

William Ordemann joined us as a Vice President of Enterprise GP in October 1999 and was elected a Senior Vice President in September 2001. From January 1997 to February 1998, Mr. Ordemann was a Vice President of Shell Midstream Enterprises, LLC, and from February 1998 to September 1999 was a Vice President of Tejas Natural Gas Liquids, LLC, both Shell affiliates.

Gil H. Radtke was elected a Senior Vice President of Enterprise GP in February 2002. Mr. Radtke joined us in connection with our purchase of Diamond-Koch's storage and propylene fractionation assets in January and February 2002. Before joining us, Mr. Radtke served as President of the Diamond-Koch joint venture from 1999 to 2002, where he was responsible for its storage, propylene fractionation, pipeline and NGL fractionation businesses. From 1997 to 1999 he was Vice President, Petrochemicals and Storage of Diamond-Koch.

James M. Collingsworth joined Enterprise GP as a Vice President in November 2001 and was elected a Senior Vice President in November 2002. Previously, he served as a board member of Texaco Canada Petroleum Inc. from July 1998 to October 2001 and was employed by Texaco from 1991 to 2001 in various management positions, including Senior Vice President of NGL Assets and Business Services from July 1998 to October 2001.

James A. Cisarik was elected a Senior Vice President of Enterprise GP in February 2003. Mr. Cisarik joined us in April 2001 when we acquired Acadian Gas from Shell. His primary responsibility since joining us has been oversight of the commercial activities of our natural gas businesses, principally those of Acadian Gas and our Gulf of Mexico natural gas pipeline investments. From February 1999 through March 2001, Mr. Cisarik was a Senior Vice President of Coral Energy, LLC. and from 1997 to February 1999 was Vice President, Market Development of Tejas Energy, LLC, both affiliates of Shell, with responsibilities in market development for their Texas and Louisiana natural gas pipeline systems.

Lynn L. Bourdon, III, was elected a Senior Vice President of Enterprise GP on December 10, 2003. His primary responsibility since joining us has been oversight of all NGL supply and marketing functions. Previously, Mr. Bourdon served as Senior Vice President and Chief Commercial Officer of Orion Refining Corporation from July 2001 through November 2003, and was a shareholder in En*Vantage, Inc., a business investment and energy services company serving the petrochemicals and energy industries, from September 1999 through July 2001. He also served as a Senior Vice President of PG&E Corporation for gas transmission commercial operations from August 1997 through August 1999.

Bart H. Heijermans was elected Senior Vice President of Enterprise GP in September 2004. Mr. Heijermans served as GulfTerra's Vice President, Offshore from June 2003 until September 2004. From June 2001 to June 2003, he served as GulfTerra's Vice President, Deepwater Project Development. He served as GulfTerra's Vice President, Operations and Engineering from August 1997 to June 2001. Prior to joining GulfTerra, Mr. Heijermans served in various capacities in the development and construction of offshore oil and gas infrastructure for Shell E&P International and Shell Research in The Netherlands, the United Kingdom and the U.S.

Richard A. Hoover was elected Senior Vice President of Enterprise GP in September 2004. Mr. Hoover served as GulfTerra's Vice President Western Division – Commercial from January 2001 until September 2004. This position included management of GulfTerra's San Juan and Permian Basin assets. Mr. Hoover has held various other commercial positions since joining GulfTerra in June 1996, including management of assets in the Texas Gulf Coast, Anadarko Basin, Mid Continent and Rockies. Prior to joining GulfTerra, Mr. Hoover held various positions over 16 years in the Midstream, Independent Power and E&P sectors with Delhi Pipeline Corporation, Panda Energy Corporation and Champlin Petroleum Corporation.

Joel D. Moxley was elected Senior Vice President of Enterprise GP in September 2004. Mr. Moxley served as GulfTerra's Vice President, Processing and NGL Marketing from December 2000 until September 2004. From August 1997 to December 2000, Mr. Moxley was a Vice President at PG&E Gas Transmission-Texas where he had responsibilities for gas processing, supply and NGL marketing. Mr. Moxley held various positions with natural gas, gas processing and business development operations at Valero Energy Corporation from July 1991 to July 1997. He spent the first 11 years of his career at Occidental Petroleum where he served in various engineering, operations, marketing and business development positions within the gas processing division.

Michael J. Knesek was elected Senior Vice President, Controller and Principal Accounting Officer of Enterprise GP and EPCO in February 2005, having served as Vice President, Controller and Principal Accounting Officer since August 2000. Since 1990, Mr. Knesek, a certified public accountant, has been the Controller and a Vice President of EPCO. Mr. Knesek devotes approximately 90% of his time to our business and affairs.

W. Randall Fowler joined us as director of investor relations in January 1999 and was elected to the positions of Treasurer and a Vice President of Enterprise GP and EPCO in August 2000 and Senior Vice President of Enterprise GP and EPCO in February 2005. Mr. Fowler devotes approximately 70% of his time to our business and affairs.

Dr. Ralph S. Cunningham was elected a Director of Enterprise GP in April 1998. Dr. Cunningham retired in 1997 from CITGO Petroleum Corporation, where he had served as President and Chief Executive Officer since 1995. Dr. Cunningham serves as a Director of Tetra Technologies, Inc. (a publicly traded energy services and chemicals 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. Dr. Cunningham serves as Chairman of our Audit and Conflicts Committee and a member of the Governance Committee.

Lee W. Marshall, Sr. was elected a Director of Enterprise GP in April 1998. Mr. Marshall has been the Managing Partner and principal owner of Bison Resources, LLC, (a privately held oil and gas production company) since 1993. Previously, he held senior management positions with Union Pacific Resources, as Senior Vice President, Refining, Manufacturing and Marketing, with Wolverine Exploration Company as Executive Vice President and Chief Financial Officer and with Tenneco Oil Company as Senior Vice President, Marketing. Mr. Marshall is a member of our Audit and Conflicts Committee.

W. Matt Ralls was elected to a Director of Enterprise GP in September 2004. Mr. Ralls served as a Director of GulfTerra's general partner from May 2003 to September 2004 and is the Senior Vice President and Chief Financial Officer of GlobalSantaFe, an international contract drilling company. From 1997 to 2001, he was Vice President, Chief Financial Officer and Treasurer of Global Marine, Inc. Previously, he served as Executive Vice President, Chief Financial Officer and Director of Kelly Oil and Gas Corporation and then briefly as Vice President of Capitals Markets and Corporate Development for the Meridian Resource Corporation before joining Global Marine. He spent the first 17 years of his career in commercial banking, mostly at the senior management level. Mr. Ralls is a member of our Audit and Conflicts Committee and serves as Chairman of Enterprise GP's Governance Committee.

Richard S. Snell was elected a Director of Enterprise GP in June 2000. Mr. Snell was an attorney with the Snell & Smith, P.C. law firm in Houston, Texas from the founding of the firm in 1993 until May 2000. Since May 2000, he has been a partner with the firm of Thompson & Knight LLP in Houston, Texas and is a certified public accountant. Mr. Snell is a member of Enterprise GP's Governance Committee.

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 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 Dr. Ralph S. Cunningham, Lee W. Marshall, Sr. and W. Matt Ralls. 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 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 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 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 as of August 19, 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 GP's Board of Directors is comprised of the three independent directors (W. Matt Ralls, Chairman, Dr. Ralph S. Cunningham and Richard S. Snell). The Governance Committee is appointed by the Board to assist the Board in fulfilling its oversight responsibilities. The 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.

Section 16(a) Beneficial Ownership Reporting Compliance

Under the federal securities laws, Enterprise GP, directors of Enterprise 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 in 2004. One report, covering one transaction in 2004, was filed late by Richard S. Snell, a director.

ITEM 11. EXECUTIVE COMPENSATION.

We do not directly employ any of the persons responsible for managing or operating our business. Instead, we are managed by Enterprise GP, the executive officers of which are employees of, and the compensation of whom is paid by EPCO. Our reimbursement to EPCO for these costs is governed by the Administrative Services Agreement. For a complete discussion of the Administrative Services Agreement, please read Item 13 of this annual report.

That portion of the compensation of O.S. Andras, who was the CEO of Enterprise GP during 2004, attributable to his services performed on our behalf has been reimbursed to EPCO through our payments under the Administrative Services Agreement. Of the other EPCO employees serving Enterprise GP whose compensation was wholly or partially reimbursed by us during 2004 under the Administrative Services Agreement, the four next most highly compensated individuals were A.J. Teague, Charles E. Crain, James M. Collingsworth and W. Ordemann. Collectively, these five individuals (including Mr. Andras) represent our "named executive officers" for 2004 as defined under Item 402(a)(3) of SEC Regulation S-K.

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Summary Compensation Table

The following table sets forth certain compensation information for our named executive officers for the years ended December 31, 2004, 2003 and 2002.

Name and Principal Position with Enterprise GP during 2004	Year	Annual Compensation		Long-term Compensation Awards		All Other Compensation (2)
		Salary	Bonus	Restricted Unit Awards ($)(1)	Securities Underlying Options (#)	
O.S. Andras, CEO(3)	2004	$ 798,000				$ 10,997
	2003	877,800				11,865
	2002	864,000				13,671
A.J. Teague	2004	392,500	$ 50,000	$ 251,400(4)	35,000	22,947
	2003	381,280	80,000			20,583
	2002	370,000	70,000			17,240
Charles E. Crain	2004	267,000	50,000	621,667(5)	25,000	20,698
	2003	250,500	50,000			20,348
	2002	240,000	50,000			17,089
James M. Collingsworth	2004	260,000	50,000	125,700(6)	25,000	19,208
	2003	206,250	50,000			17,465
	2002	181,250				76,882
W. Ordemann	2004	242,500	50,000	125,700(7)	25,000	14,968
	2003	209,917	50,000			14,468
	2002	209,000	60,000			14,398

(1) The dollar value of restricted common unit awards to the named executive officers is calculated by multiplying the number of restricted units awarded by the closing price of our unrestricted common units on the date of each grant. All distributions on the restricted units subject to these awards are paid to the holders thereof on the respective distribution dates.

(2) These amounts primarily represent contributions made by EPCO to the 401(K) plan and the employee unit purchase plan of the named executive officers.

(3) Mr. Andras served as CEO of Enterprise GP from April 1998 to February 11, 2005, at which time Mr. Phillips assumed the role of CEO of our general partner. In accordance with Item 402(a)(3)(i) of SEC Regulation S-K, disclosure of Mr. Andras' compensation is required since he served as CEO of Enterprise GP during the last completed fiscal year.

(4) At December 31, 2004, Mr. Teague held 12,000 restricted common units valued at $310,320 based on a closing price of $25.86 per unit for our unrestricted common units on that date.

(5) At December 31, 2004, Mr. Crain held 27,277 restricted common units valued at $705,383 based on a closing price of $25.86 per unit for our unrestricted common units on that date.

(6) At December 31, 2004, Mr. Collingsworth held 6,000 restricted common units valued at $155,160 based on a closing price of $25.86 per unit for our unrestricted common units on that date.

(7) At December 31, 2004, Mr. Ordemann held 6,000 restricted common units valued at $155,160 based on a closing price of $25.86 per unit for our unrestricted common units on that date.

Common unit option grants to named executive officers during 2004

The following table provides information concerning grants of options to purchase our common units by EPCO to each of the named executive officers during 2004. Mr. Andras did not receive any grants of options during 2004.

Name	Number of Securities Underlying Options Granted (#)	Individual Grants Percent of Total Options Granted to EPCO Employees in 2004	Exercise Price ($/Unit)	Expiration Date	Potential Realizable Value at Assumed Annual Rates of Unit Price Appreciation for Option Term (1)	
					5% ($)	10% ($)
A. J. Teague	35,000	3.85%	$ 20.00	May 2014	$ 440,300	$ 1,115,450
Charles E. Crain	25,000	2.75%	$ 20.00	May 2014	314,500	796,750
James M. Collingsworth	25,000	2.75%	$ 20.00	May 2014	314,500	796,750
W. Ordemann	25,000	2.75%	$ 20.00	May 2014	314,500	796,750

(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 certain information concerning (i) the exercise of options to purchase common units by each named executive officer during 2004 and (ii) the value of unexercised common unit options at December 31, 2004. Mr. Andras does not hold any options to purchase our units at December 31, 2004 nor did he exercise any options during 2004.

Name	Units Acquired on Exercise (#)	Value Realized ($)(1)	Number of Securities Underlying Unexercised Options at December 31, 2004		Value of Unexercised In-the-Money Options at December 31, 2004(2)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
A. J. Teague	100,000	$ 1,057,000	100,000	35,000	$ 993,000	$ 205,100
Charles E. Crain	60,000	768,000		25,000		146,500
James M. Collingsworth			50,000	25,000	131,000	146,500
W. Ordemann	40,000	258,000		25,000		146,500

(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) The value is based on the $25.86 closing price of our common units on December 31, 2004.

Compensation Committee Interlocks and Insider Participation

As stated above, the compensation of the executive officers of Enterprise GP is paid by EPCO and we reimburse EPCO for that portion of its compensation expense that is related to our business, pursuant to the Administrative Services Agreement. For the year ended December 31, 2004, O.S. Andras, Vice Chairman and a director of EPCO, determined the amount of cash compensation paid by EPCO to the executive officers of Enterprise GP other than himself, and Dan L. Duncan, Chairman of the Board of EPCO, determined the amount of cash compensation paid by EPCO to Mr. Andras. No compensation expense is borne by us with respect to Mr. Duncan. See Item 13 of this annual report for information regarding transactions between us and EPCO, which is controlled by Mr. Duncan.

Compensation of Directors of Enterprise GP

Neither we nor Enterprise GP provide any additional compensation to employees of EPCO who serve as directors of Enterprise GP. The employees of EPCO who served as directors of Enterprise GP during 2004 were Mr. Duncan, Mr. Andras and Mr. Phillips.

The four independent outside directors — Dr. Cunningham, Mr. Marshall, Mr. Snell and Mr. Ralls — are compensated for their services at the expense of Enterprise GP. Prior to completion of the GulfTerra Merger on September 30, 2004, our then independent directors (Dr. Cunningham, Mr. Marshall and Mr. Snell) received compensation for their services as follows: (i) an annual retainer of $22,500, (ii) $1,250 for each meeting of the Board of Directors they attended, (iii) $625 for each meeting of a committee of the Board of Directors they attended and (iv) an annual retainer of $5,750 for serving as chairman of a committee of the Board of Directors. Under this compensation arrangement, Enterprise GP paid the three independent directors 40% in cash and 60% in our common units. The combined total value of compensation paid to Dr. Cunningham, Mr. Marshall and Mr. Snell during 2004 under this arrangement was $86,375, of which $34,550 was paid in cash and the remainder consisted of the value of common units issued over the course of the nine months in 2004 that this arrangement was in place.

Effective October 1, 2004, Enterprise GP revised the compensation arrangements for its independent directors as follows: (i) an annual retainer of $25,000 in cash and $25,000 worth of restricted common units and (ii) an annual retainer of $7,500 in cash for serving as chairman of a committee of the Board of Directors. The total value of compensation paid to Dr. Cunningham, Mr. Marshall, Mr. Snell and Mr. Ralls during 2004 under this arrangement was $53,750, of which $28,750 was paid in cash and the remainder consisted of the aggregate value of 1,076 restricted common units issued to these directors in November 2004.

In addition, Dr. Cunningham, Mr. Marshall and Mr. Snell have been granted options to acquire our common units as a result of independent director compensation arrangements made prior to 2004. Collectively, these directors had 80,000 common unit options outstanding at December 31, 2004 and March 1, 2005. None of these options were exercised during 2004.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS.

Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information as of March 15, 2005, regarding the beneficial ownership of our common units by (i) all persons known by Enterprise GP to beneficially own more than 5% of the common units, (ii) the directors and certain executive officers of Enterprise GP and (iii) all directors and executive officers of Enterprise GP as a group. Each person has sole voting and dispositive power over the units shown unless otherwise indicated below. We had 383,554,318 common units outstanding at March 15, 2005.

	Common Units	
	Number of Units	Percent of Class
Dan L. Duncan:		
Units owned by EPCO(1)	131,532,925	34.3%
Units owned by trusts(2)	11,387,615	3.0%
Units owned directly	530,238	0.1%
Total for Dan L. Duncan	143,450,778	37.4%
Shell US Gas & Power LLC(3)	36,572,122	9.5%
O.S. Andras(4)	3,520,741	*
Robert G. Phillips	75,797	*
Dr. Ralph S. Cunningham (5)	22,795	*
Lee W. Marshall(6)	31,512	*
Richard S. Snell (7)	51,182	*
W. Matt Ralls	4,642	*
A.J. Teague(4,8)	215,557	*
Charles E. Crain(4)	157,774	*
James M. Collingsworth(4,9)	66,586	*
W. Ordemann(4)	21,898	*
All directors and executive officers of Enterprise GP as a group, (22 individuals in total)(10)	148,456,655	38.7%

** The beneficial ownership of each is less than 1% of our common units outstanding.*

(1) EPCO owns its units through a wholly owned subsidiary, Enterprise Products Delaware Holdings, L.P., and a 95% owned subsidiary, Enterprise GP Holdings, L.P. Enterprise GP Holdings is owned 5% by another entity that is wholly owned and controlled by Mr. Duncan. 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) In addition to the units owned by EPCO, Dan L. Duncan has beneficial ownership of common units owned by the Duncan Family 1998 Trust and Duncan Family 2000 Trust, the beneficiaries of which are the shareholders of EPCO.

(3) We issued these units to Shell US Gas & Power LLC (an affiliate of Shell) in connection with our acquisition of certain of Shell's U.S. Gulf Coast midstream energy assets in 1999 and a related contingent unit agreement. The address of Shell US Gas & Power LLC is 910 Louisiana Street, Houston, Texas 77002.

(4) These individuals are the "named executive officers" for 2004 (see Item 11).

(5) Dr. Cunningham's beneficial ownership amount includes 20,000 common unit options issued under the equity compensation plan of EPCO that are exercisable within 60 days of the filing date of this report.

(6) Mr. Marshall's beneficial ownership amount includes 20,000 common unit options issued under the equity compensation plan of EPCO that are exercisable within 60 days of the filing date of this report.

(7) Mr. Snell's beneficial ownership amount includes 40,000 common unit options issued under the equity compensation plan of EPCO that are exercisable within 60 days of the filing date of this report. The number of common units shown for Mr. Snell include 6,000 common units held by family trusts and 1,100 common units owned by his wife, for which he has disclaimed beneficial ownership.

(8) Mr. Teague's beneficial ownership amount includes 100,000 common unit options issued under the equity compensation plan of EPCO that were exercisable within 60 days of the filing date of this report.

(9) Mr. Collingsworth's beneficial ownership amount includes 50,000 common unit options issued under the equity compensation plan of EPCO that were exercisable within 60 days of the filing date of this report.

(10) Cumulatively, this group's beneficial ownership amount includes 640,000 common unit options issued under the equity compensation plan of EPCO that are exercisable within 60 days of the filing date of this report.

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EPCO has pledged substantially all of its common units and its 95% ownership interest in Enterprise GP as security under its revolving credit facility with a syndicate of banks. EPCO's revolving credit facility contains customary and other events of default relating to defaults of EPCO and certain of its subsidiaries, including certain defaults of Enterprise and other EPCO affiliates. An event of default, followed by a foreclosure on EPCO's pledged collateral could result in a change in control of Enterprise.

On March 3, 2005, we filed a universal shelf registration with the SEC covering the issuance of $4 billion of partnership equity and public debt obligations (separately or in combination). In connection with this registration statement, we also registered for resale 36,572,122 common units currently owned by Shell and 4,427,878 common units that had been sold by Shell to Kayne Anderson MLP Investment Company in December 2004. We are obligated to register the resale of these common units under a registration rights agreement we executed with Shell in connection with our acquisition of certain of Shell's Gulf Coast midstream energy businesses in September 1999.

For a discussion of our capital structure, please read Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2004 regarding the equity compensation plan of our affiliate, EPCO, under which our common units are authorized for issuance to its key employees and to directors of Enterprise GP.

Plan Category	Number of securities to be issued upon exercise of outstanding common unit options (a)	Weighted-average exercise price of outstanding common unit options (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by unitholders:			
1998 Plan	2,463,000	$ 18.84	3,367,552
Equity compensation plans not approved by unitholders:			
None.			
Total for equity compensation plans	2,463,000	$ 18.84	3,367,552

The Enterprise Products 1998 Long-Term Incentive Plan (the "1998 Plan") is intended to promote our interests by encouraging employees and directors of EPCO and its affiliates who perform services for us to acquire or increase their ownership of our common units and to provide a means whereby they may develop a sense of proprietorship and personal involvement in our development and financial success through the award of common unit options. The 1998 Plan was developed to encourage recipients of common unit options to remain with us and to devote their best efforts to our business, thereby advancing the interests of all unitholders and our general partner. The 1998 Plan also enhances our ability to attract and retain the services of key individuals who are essential for our growth and profitability.

The 1998 Plan is governed by our Audit and Conflicts Committee (the "Committee"), whose significant powers include, but are not limited to, (i) designating participants in the plan; (ii) determining the number of common units to be covered by the equity awards; (iii) determining the terms and conditions of any equity award; and (iv) determining, whether, to what extent, and under what circumstances participants may settle, exercise, cancel or forfeit any equity award. Subject to adjustment as provided in the 1998 Plan documents, the number of common units that may be awarded to participants is 7,000,000, of which 3,367,552 remain available for awards at December

31, 2004. The common units to be awarded under this plan may be obtained through purchases made on the open market or from affiliates of EPCO or from us.

The exercise price of common unit options issued to participants is determined by the Committee (at its discretion) at the date of grant and may be equal to, greater or less than its fair market value as of the date of grant. The Committee determines the time or times at which the awards may be exercised in whole or in part, and the method or methods by which any payment of the exercise price with respect thereto may be made or deemed to have been made, which may include cash, notes receivable from the participant, or cashless-broker transactions or other acceptable forms of payment. In addition, to the extent provided by the Committee, a common unit option grant may include a contingent right to receive an amount in cash equal to any cash distributions made by us with respect to the underlying common units during the period the award is outstanding.

The 1998 Plan also provides for the issuance of restricted common units. During 2004, a total of 434,225 restricted common units were issued to key employees of EPCO and our four independent directors under the 1998 Plan. A total of 1,000,000 restricted common units can be issued under the 1998 Plan, of which 565,775 remain authorized for issuance at December 31, 2004. For information regarding our restricted common units, please read Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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. A second plan, the Enterprise Products 1999 Long-Term Incentive Plan, is inactive and has no options outstanding. At present, we have no intention of issuing options under this second plan.

Commitments under equity compensation plans of EPCO

Categories of equity-based awards and our general commitments under each

Equity-based awards granted to certain key operations employees. Under the Administrative Services Agreement (see Item 13 of this annual report), we reimburse EPCO for the compensation of all operations personnel it employs on our behalf. This includes the costs attributable to equity-based awards granted to these personnel. When these employees exercise unit options, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units awarded to the employee. We may reimburse EPCO for these costs by either furnishing cash, reissuing treasury units or by issuing new common units.

Equity-based awards granted to certain key administrative and management employees. Effective January 1, 2004, we began reimbursing EPCO for the compensation of all administrative and management personnel it employs on our behalf. This includes the costs attributable to equity-based awards granted to these personnel. When these employees exercise unit options, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units awarded to the employee. We may reimburse EPCO for these costs by either furnishing cash, reissuing treasury units or by issuing new common units.

Prior to January 1, 2004, our compensation obligation was differentiated between administrative and management personnel EPCO hired in response to our expansion and new business activities and those EPCO employees in administrative and management positions that were active at the time of our initial public offering in July 1998. The cost of equity-based awards associated with such personnel hired in response to our expansion and new business activities was accounted for as described in the previous paragraph. The cost of equity-based awards associated with such personnel that were active at the time of our initial public offering was covered under the Administrative Services Fee we paid to EPCO. EPCO was responsible for the actual costs when the unit awards granted to these pre-expansion employees were exercised. EPCO satisfied its equity-award obligations to the pre-expansion employees by arranging for common units to be purchased in the open market or from us.

Our commitments at December 31, 2004

At December 31, 2004, there were 2,463,000 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 to this group was $18.84 per common unit at December 31, 2004 and 1,154,000 of these unit options were exercisable. An additional 374,000, 25,000 and 910,000 of these common unit options will be exercisable in 2005, 2006 and 2008, respectively.

Employee Unit Purchase Plan

The Enterprise Unit Purchase Plan gives all eligible employees the opportunity to purchase common units at a 10% discount from an average market price (as defined by the plan) through voluntary payroll deductions. The purchase price is paid 90% by the employee and 10% by EPCO (which amount is reimbursed by us). Generally, an eligible employee is a regular, active full-time employee who has been employed by EPCO for at least three months and works on our business for at least 30 hours per week. During the year ended December 31, 2004, a total of 96,534 common units were purchased directly under this plan, at a cost of $0.2 million being incurred by EPCO for the 10% discount.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

The following table summarizes our related party transactions for the periods indicated (in thousands of dollars):

	For Year Ended December 31,		
	2004	2003	2002
Revenues from consolidated operations			
EPCO and subsidiaries	$ 2,697	$ 4,241	$ 3,630
Shell	542,912	293,109	282,820
Unconsolidated affiliates	258,541	266,894	196,267
Total	$ 804,150	$ 564,244	$ 482,717
Operating costs and expenses			
EPCO and subsidiaries	$ 202,561	$ 149,626	$ 103,210
Shell	725,420	607,277	531,712
Unconsolidated affiliates	37,587	43,752	60,657
Total	$ 965,568	$ 800,655	$ 695,579
Selling, general and administrative expenses			
EPCO Administrative Services Agreement	$ 27,454	$ 27,518	$ 24,204
Other EPCO transactions	653	442	n/a
Total	$ 28,107	$ 27,960	$ 24,204

Relationship with EPCO

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise GP, our general partner. In addition, the executive and other officers of Enterprise GP are employees of EPCO, including Robert G. Phillips who is Chief Executive Officer and a director of Enterprise GP. The principal business activity of Enterprise GP is to act as our managing partner.

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. In addition, at December 31, 2004, EPCO and Dan Duncan LLC, together, owned 90.1% of the membership interests of Enterprise GP, which in turn owns a 2% general partner interest in us. In January 2005, an affiliate of EPCO, Enterprise GP Holdings L.P., acquired El Paso's 9.9% membership interest in Enterprise GP. As a result of this transaction, EPCO and its affiliates own 100% of Enterprise GP. For additional information regarding this subsequent event, please read Note 21 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

In addition, trust affiliates of EPCO, the beneficiaries of which are the shareholders of EPCO (the 1998 Trust and 2000 Trust), owned 11,387,615 of our common units at March 15, 2005. Collectively, Mr. Duncan, through his beneficial ownership of our common units held personally, by the 1998 and 2000 Trusts and through subsidiaries of EPCO, controlled 37.4% of our common units at March 15, 2005. For additional information regarding the beneficial ownership of our common units, please read Item 12 of this annual report.

Our agreements with EPCO are not the result of arm's-length transactions, and there can be no assurance that any of the transactions provided for therein are effected on terms at least as favorable to the parties to such agreement as could have been obtained from unaffiliated third parties.

Administrative Services Agreement. As stated previously, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative Services Agreement. Under the current terms of the Administrative Services Agreement, EPCO agrees to:

- employ the personnel necessary to manage our business and affairs (through Enterprise GP);
- employ the operating personnel involved in our business;
- allow us to participate as named insureds in EPCO's current insurance program with the costs being allocated among the parties on the basis set forth in the agreement; and
- sublease to us certain equipment which it holds pursuant to operating leases for one dollar per year and to assign to us its purchase option under such leases (the "retained leases"). EPCO remains liable for the cash lease payments associated with these assets.

Operating costs and expenses (as shown on our Statements of Consolidated Operations and Comprehensive Income) treat the retained lease-related payments made by EPCO on our behalf as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded as a general contribution to the partnership. As of December 31, 2004, the remaining retained leases were for a cogeneration unit and approximately 100 railcars. During 2004, we exercised our options to purchase an isomerization unit and related equipment at a cost of $17.8 million. Should we decide to exercise the purchase options associated with the remaining retained leases (which are also at fair value), an additional $2.3 million would be payable in 2008 and $3.1 million in 2016. In addition to retained lease expense, operating costs and expenses include compensation charges for EPCO's employees who operate our facilities.

Selling, general and administrative costs (as shown in our Statements of Consolidated Operations and Comprehensive Income) include the costs we pay EPCO for administrative support. Prior to January 1, 2004, our payments to EPCO and related non-cash expenses for administrative support were based on the following:

- We reimbursed EPCO for our share of the costs of certain of its employees in administrative positions that were active at the time of our initial public offering in July 1998 (the "pre-expansion" administrative personnel). This includes costs associated with equity-based awards granted to certain individuals within this group. Our obligation for reimbursing these costs was covered by the EPCO Administrative Service Fee. We paid $17.9 million and $16.6 million of such fees to EPCO during 2003 and 2002, respectively.
- To the extent that EPCO's actual cost of providing the pre-expansion administrative personnel exceeded the Administrative Service Fee charged us during a given year, we recorded a non-cash expense equal to the difference as a non-cash selling, general and administrative cost. The offset was recorded in Partners' Equity on the Consolidated Balance Sheets as a general contribution to the partnership. The actual amounts incurred by EPCO for providing these services did not materially exceed the capped amount for the year ended December 31, 2002. For the year ended December 31, 2003, we recorded $0.4 million in non-cash expense related to this excess.
- We also reimburse EPCO for all costs it incurs related to administrative personnel it hires in response to our expansion and new business activities. This includes costs attributable to equity-based awards granted to members of this group.

Effective January 1, 2004, the Administrative Services Agreement was amended to eliminate the fixed Administrative Services Fee and to provide that we reimburse EPCO for all costs related to administrative support regardless of whether the costs are related to pre-expansion or expansion personnel who work on our behalf.

On October 22, 2004, the Administrative Services Agreement was amended further to evidence our separateness from other persons and entities, to reflect a five-year license we granted for EPCO's use of service marks owned by us and to provide for reimbursement of EPCO's costs of discontinuing the use of those service marks over the term of the license. This amendment also provides that if EPCO and its affiliates are offered by a third party, or discover an opportunity to acquire from a third party, a business or assets that is or are in the same or similar line of business then being conducted by the Operating Partnership or in a line of business that would be a natural extension of any business then being conducted by the Operating Partnership (a "Business Opportunity"), EPCO shall promptly advise the Board of Directors of Enterprise GP of such Business Opportunity and offer such Business Opportunity to the Operating Partnership. If the Board of Directors of Enterprise GP does not advise EPCO within 10 days following the receipt of such notice that we wish to pursue such Business Opportunity, EPCO shall then be permitted to pursue such Business Opportunity. If the Board of Directors of Enterprise GP advises EPCO within such 10 day period that we want to pursue such Business Opportunity, EPCO shall not be permitted to pursue such Business Opportunity unless the Board of Directors of Enterprise GP subsequently advises EPCO that it has abandoned its pursuit of such Business Opportunity.

Other related party transactions with EPCO. The following is a summary of other significant related party transactions between EPCO and us, including those between EPCO and our unconsolidated affiliates.

- Prior to January 1, 2004, EPCO was the operator of our MTBE facility and Houston Ship Channel NGL import facility. During 2003 and 2002, we paid EPCO $0.8 million for such services. Such payments were terminated effective January 1, 2004.

- We have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLs and other products.

- In the normal course of business, we also buy from and sell to EPCO's Canadian affiliate certain NGL products.

We and Enterprise GP are separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from EPCO and its other affiliates. EPCO primarily depends on the cash distributions it receives as an equity owner in us and its other investments (including the recent acquisition of TEPPCO's general partner and 2.5 million TEPPCO common units) to fund its other operations and to meet its debt obligations. For the years ended December 31, 2004, 2003 and 2002, EPCO received $173.7 million, $160.4 million and $146.6 million, respectively, in quarterly cash distributions from us.

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At March 15, 2005, Shell owned approximately 9.5% of our common units. Shell sold its 30.0% interest in Enterprise GP to a subsidiary of EPCO in September 2003.

Shell is one of our largest customers. For the years ended December 31, 2004, 2003 and 2002, Shell accounted for 6.5%, 5.5% and 7.9%, 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.

The most significant contract affecting our natural gas processing business is the Shell margin-band/keepwhole processing agreement, which grants us the right to process Shell'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. For additional information regarding this contract, please read "*The Company's Operations - NGL Pipelines & Services - Natural Gas Processing and related NGL Marketing Activities*" included under Item 1 of this annual report.

We have also completed a number of business acquisitions and asset purchases involving Shell since 1999, including the acquisition of midstream energy assets located along the Gulf Coast for approximately $528.8 million in 1999; the purchase of the Lou-Tex Propylene pipeline for $100 million in 2000; and the acquisition of the Acadian Gas pipeline system in 2001 for $243.7 million.

On March 3, 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of partnership equity and public debt obligations. In connection with this registration statement, we also registered for resale 36,572,122 common units currently owned by Shell and 4,427,878 common units that had been sold by Shell to Kayne Anderson MLP Investment Company. Shell sold these unregistered units to Kayne Anderson in December 2004. We are obligated to register the resale of these common units under a registration rights agreement we executed with Shell in connection with our acquisition of certain of Shell's Gulf Coast midstream energy businesses in September 1999.

Relationships with unconsolidated affiliates

Our investment in unconsolidated affiliates with industry partners is a vital component of our business strategy. These investments are a means by which we conduct our operations to align our interests with a supplier of raw materials or a consumer 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. The following summarizes significant related party transactions we have 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. For the years ended December 31, 2004, 2003 and 2002, revenues from Evangeline were $233.9 million, $212.7 million and $131.6 million, respectively. In addition, we have also furnished $11.1 million in letters of credit on behalf of Evangeline.

- We pay transportation fees to Dixie for propane movements on their system initiated by our NGL marketing activities. For the years ended December 31, 2004, 2003 and 2002, we paid Dixie $13.1 million, $11.3 million and $12.2 million, respectively, in such transportation fees.

- We pay Promix for the transportation, storage and fractionation of certain of our mixed NGL volumes. In addition, we sell natural gas to Promix for their fuel requirements. For the years ended December 31, 2004, 2003 and 2002, we paid Promix $23.2 million, $17.5 million and $18.4 million, respectively, for their services. Additionally, for the years ended December 31, 2004, 2003 and 2002, revenues from Promix for the purchase of natural gas were $18.6 million, $19.6 million and $12.7 million, respectively.

Prior to its becoming a consolidated subsidiary in March 2003, we paid EPIK for export services to load product cargoes for our NGL and petrochemical marketing customers. Also, prior to its becoming a consolidated subsidiary in September 2003, we sold high purity isobutane to BEF as a feedstock and purchased certain of BEF's by-products. We also received transportation fees for BEF's shipments of MTBE on our HSC pipeline and fractionation revenues for reprocessing mixed feedstock streams generated by BEF.

We enter into management agreements with some of our unconsolidated affiliates under which our unconsolidated affiliates pay us management fees for the operation and management of their assets. For the years ended December 31, 2004, 2003 and 2002, such fees approximated $2.1 million, $1.5 million and $1.4 million, respectively. Additionally, on occasion we pay for construction costs on behalf of our unconsolidated affiliates during the initial construction phase of their assets, and these amounts are settled by direct reimbursements for the amounts we are owed from our unconsolidated affiliates.

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,	
	2004	2003
Audit Fees (1)	$ 5,227	$ 2,027
Audit-Related Fees (2)	32	4
Tax Fees(3)	586	973
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, (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 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) and (2) Financial Statements and Financial Statement Schedules.

See "Index to Financial Statements and Supplemental Schedule" set forth on page F-1.

(a)(3) Exhibits.

Exhibit No.	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 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 filed December 27, 2004).

Exhibit No.	Exhibit*
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	Fourth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of October 1, 2004 (incorporated by reference to Exhibit 3.1 to Form 8-K filed October 6, 2004).
3.2	Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, among Duncan Family Interests, Inc., Dan Duncan LLC, and GulfTerra GP Holding Company dated September 30, 2004 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 30, 2004).
3.3	Application for Admission by Enterprise GP Holdings L.P. as a Substituted Member of Enterprise Products GP, LLC (incorporated by reference to Exhibit 3.1 to Form 8-K filed January 18, 2005).
3.4	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 3.3 to Form 10-Q filed August 9, 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 Note representing $350 million principal amount of 8.25% Senior Notes due 2005 (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 10, 2000).
4.7	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).
4.8	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).
4.9	Contribution Agreement dated September 17, 1999 (incorporated by reference to Exhibit "B" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.10	Registration Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "E" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.11	Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "C" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.12	Amendment No. 1, dated September 12, 2003, to Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit 4.1 to Form 8-K filed September 15, 2003).
4.13	Agreement dated as of March 4, 2004 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, 2004).
4.14	$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, Mizuho Corporate Bank, Ltd., SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents, Wachovia Capital Markets, LLC, CitiGroup Global Markets Inc. and JPMorgan Chase Securities, Inc., as Joint Lead Arrangers and Joint Book Runners

Exhibit No.	Exhibit*
	(incorporated by reference to Exhibit 4.1 to Form 8-K filed on August 30, 2004).
4.15	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 4.1, above (incorporated by reference to Exhibit 4.2 to Form 8-K filed on August 30, 2004).
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 4.3, 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 A 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, 2004).
4.24	Global Note representing $500 million principal amount of 5.600% Series A 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, 2004).
4.25	Global Note representing $150 million principal amount of 5.600% Series A 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, 2004).
4.26	Global Note representing $350 million principal amount of 6.650% Series A 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, 2004.
4.27#	Global Note representing $500 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee.
4.28	Registration Rights Agreement dated as of October 4, 2004, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.17 to Form 8-K filed on October 6, 2004).
4.29	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).

Exhibit No.	Exhibit*
4.30	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).
4.31	Rule 144A Global Note representing $250,000,000 principal amount of 5.00% Series A Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed on March 3, 2005).
4.32	Rule 144A Note representing $250,000,000 principal amount of 5.75% Series A Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed on March 3, 2005).
4.33	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).
4.34	Exchange and Registration Rights Agreement, dated as of September 30, 2004, among GulfTerra GP Holding Company, Enterprise Products GP, LLC and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 4.1 to Form 8-K filed on September 30, 2004).
4.35	Performance Guaranty dated as of September 30, 2004, by DFI Delaware Holdings L.P. in favor of GulfTerra GP Holding Company (incorporated by reference to Exhibit 4.2 to Form 8-K filed on September 30, 2004).
4.36	Registration Rights Agreement, dated as of September 30, 2004, between El Paso Corporation and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 4.3 to Form 8-K filed on September 30, 2004).
4.37	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).
4.38	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).
4.39	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).
4.40	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).
4.41	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).
4.42	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 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).

Exhibit No.	Exhibit*
4.43	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).
4.44	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).
4.45	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).
4.46	Indenture dated as of July 3, 2003, by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (Filed as Exhibit 4.L to GulfTerra's 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.47	First 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).
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	Partnership Agreement among Sun BEF, Inc., Liquid Energy Fuels Corporation and Enterprise Products Company dated May 1, 1992 (incorporated by reference to Exhibit 10.5 to Registration Statement on Form S-1 filed May 13, 1998).
10.3	Propylene Facility and Pipeline Agreement between Enterprise Petrochemical Company and Hercules Incorporated dated December 13, 1978 (incorporated by reference to Exhibit 10.9 to Registration Statement on Form S-l filed May 13, 1998).
10.4	Restated Operating Agreement for the Mont Belvieu Fractionation Facilities Chambers County, Texas among Enterprise Products Company, Texaco Producing Inc., El Paso Hydrocarbons Company and Champlin Petroleum Company dated July 17, 1985 (incorporated by reference to Exhibit 10.10 to Registration Statement on Form S-l/A filed July 8,1998).
10.5	Amendment to Propylene Facility and Pipeline Agreement and Propylene Sales Agreement between HIMONT U.S.A., Inc. and Enterprise Products Company dated January 1, 1993 (incorporated by reference to Exhibit 10.12 to Registration Statement on Form S-l/A filed July 8, 1998).
10.6	Amendment to Propylene Facility and Pipeline Agreement and Propylene Sales Agreement between HIMONT U.S.A., Inc. and Enterprise Products Company dated January 1, 1995 (incorporated by reference to Exhibit 10.13 to Registration Statement on Form S-l/A filed July 8, 1998).
10.7	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).
10.8 ***	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).
10.9 ***	Form of Option Grant Award under 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).
10.10***	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).
10.11***	Letter Agreement dated September 30, 2004, among Enterprise Products Partners L.P., GulfTerra Energy Partners, L.P. and Bart Heijermans (incorporated by reference to Exhibit 10.1 to Form 8-K/A-2 filed on October 18, 2004).
10.12***	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 the (incorporated by reference to Exhibit 10.8.1 to Form 10-Q for the

Exhibit No.	Exhibit*
	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).
10.13	Second Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products OLPGP, Inc., dated effective as of October 1, 2004 (incorporated by reference to Exhibit 10.1 to Form 8-K filed October 27, 2004).
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2004, 2003, 2002, 2001 and 2000.
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, 2004 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, 2004 annual report on Form 10-K.
32.1#	Section 1350 certification of Robert G. Phillips for the December 31, 2004 annual report on Form 10-K.
32.2#	Section 1350 certification of Michael A. Creel for the December 31, 2004 annual report on Form 10-K.

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* 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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ENTERPRISE PRODUCTS PARTNERS L.P.
INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTAL SCHEDULE

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.

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, 2004 and 2003, 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, 2004. Our audits also included the financial statement schedule listed in the Index at 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, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, 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, present 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, 2004, 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 March 15, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 15, 2005

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ENTERPRISE PRODUCTS PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2004	December 31, 2003
ASSETS		
Current Assets		
Cash and cash equivalents (includes restricted cash of $26,157 at December 31, 2004 and $13,851 at December 31, 2003)	$ 50,713	$ 44,317
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $24,310 at December 31, 2004 and $20,423 at December 31, 2003	1,058,375	462,198
Accounts receivable - related parties	25,161	347
Inventories	189,019	150,161
Assets held for sale	36,562	
Prepaid and other current assets	80,893	30,160
Total current assets	1,440,723	687,183
Property, Plant and Equipment, net	7,831,467	2,963,505
Investments in and Advances to Unconsolidated Affiliates	519,164	767,759
Intangible Assets, net of accumulated amortization of $74,183 at December 31, 2004 and $40,371 at December 31, 2003	980,601	268,893
Goodwill	459,198	82,427
Deferred Tax Asset	6,467	10,437
Long-Term Receivables	14,931	5,454
Other Assets	62,910	17,156
Total	$ 11,315,461	$ 4,802,814
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Current maturities of debt	$ 15,000	$ 240,000
Accounts payable - trade	203,142	68,384
Accounts payable - related parties	41,293	38,045
Accrued gas payables	1,021,294	622,982
Accrued expenses	130,051	24,695
Accrued interest	70,335	45,350
Other current liabilities	104,764	57,420
Total current liabilities	1,585,879	1,096,876
Long-Term Debt	4,266,236	1,899,548
Other Long-Term Liabilities	63,521	14,081
Minority Interest	71,040	86,356
Commitments and Contingencies		
Partners' Equity		
Limited Partners		
Common units (364,297,340 units outstanding at December 31, 2004 and 213,366,760 units outstanding at December 31, 2003)	5,204,940	1,582,951
Restricted common units (488,525 units outstanding at December 31, 2004)	12,327	
Class B special units (4,413,549 units outstanding at December 31, 2003)		100,182
Treasury units, at cost (427,200 units outstanding at December 31, 2004 and 798,313 units outstanding at December 31, 2003)	(8,660)	(16,519)
General partner	106,475	34,349
Accumulated other comprehensive income	24,554	4,990
Deferred compensation	(10,851)	
Total Partners' Equity	5,328,785	1,705,953
Total	$ 11,315,461	$ 4,802,814

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

STATEMENTS OF CONSOLIDATED OPERATIONS AND COMPREHENSIVE INCOME
(Dollars in thousands, except per unit amounts)

	For Year Ended December 31, 2004	2003	2002
REVENUES			
Third parties	$ 7,517,052	$ 4,782,206	$ 3,102,066
Related parties	804,150	564,225	482,717
Total	8,321,202	5,346,431	3,584,783
COST AND EXPENSES			
Operating costs and expenses			
Third parties	6,938,768	4,246,229	2,687,260
Related parties	965,568	800,548	695,579
Total operating costs and expenses	7,904,336	5,046,777	3,382,839
Selling, general and administrative costs			
Third parties	18,552	10,463	18,686
Related parties	28,107	27,127	24,204
Total selling, general and administrative costs	46,659	37,590	42,890
Total costs and expenses	7,950,995	5,084,367	3,425,729
EQUITY IN INCOME (LOSS) OF UNCONSOLIDATED AFFILIATES	52,787	(13,960)	35,253
OPERATING INCOME	422,994	248,104	194,307
OTHER INCOME (EXPENSE)			
Interest expense	(155,740)	(140,806)	(101,580)
Dividend income from unconsolidated affiliates		5,595	4,737
Interest income	2,083	772	2,313
Other, net	32	33	304
Other expense, net	(153,625)	(134,406)	(94,226)
INCOME BEFORE PROVISION FOR INCOME TAXES, MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES	269,369	113,698	100,081
PROVISION FOR INCOME TAXES	(3,761)	(5,293)	(1,634)
INCOME BEFORE MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES	265,608	108,405	98,447
MINORITY INTEREST	(8,128)	(3,859)	(2,947)
INCOME BEFORE CHANGES IN ACCOUNTING PRINCIPLES	257,480	104,546	95,500
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES (see Note 1)	10,781		
NET INCOME	$ 268,261	$ 104,546	$ 95,500
Cash flow financing hedges	19,405	5,354	(3,560)
Reclassification (amortization) of cash flow financing hedges	(1,275)	3,196	
Change in fair value of commodity hedges	1,434		
COMPREHENSIVE INCOME	$ 287,825	$ 113,096	$ 91,940

See Notes to Consolidated Financial Statements

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

	For Year Ended December 31,		
	2004	2003	2002
ALLOCATION OF NET INCOME TO:			
Limited partners' interest in net income	$ 231,153	$ 83,817	$ 84,837
General partner interest in net income	$ 37,108	$ 20,729	$ 10,663
EARNING PER UNIT: (see Note 13)			
Basic income per unit before changes in accounting principles	$ 0.83	$ 0.42	$ 0.55
Basic income per unit	$ 0.87	$ 0.42	$ 0.55
Diluted income per unit before changes in accounting principles	$ 0.83	$ 0.41	$ 0.48
Diluted income per unit	$ 0.87	$ 0.41	$ 0.48

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, 2004	2003	2002
OPERATING ACTIVITIES			
Net income	$ 268,261	$ 104,546	$ 95,500
Adjustments to reconcile net income to cash flows provided by operating activities:			
Depreciation and amortization in operating costs and expenses	193,734	115,642	86,029
Depreciation and amortization in selling, general and administrative costs	1,650	159	77
Amortization in interest expense	3,503	12,634	8,819
Equity in (income) loss of unconsolidated affiliates	(52,787)	13,960	(35,253)
Distributions received from unconsolidated affiliates	68,027	31,882	57,662
Provision for impairment of long-lived asset	4,114	1,200	
Cumulative effect of changes in accounting principles	(10,781)		
Operating lease expense paid by EPCO	7,705	9,010	9,033
Other expenses paid by EPCO		436	
Minority interest	8,128	3,859	2,947
Gain on sale of assets	(15,901)	(16)	(1)
Deferred income tax expense	9,608	10,534	2,080
Changes in fair market value of financial instruments	5	(29)	10,213
Increase in restricted cash	(12,305)	(5,100)	(2,999)
Net effect of changes in operating accounts (see Note 17)	(93,725)	120,888	92,655
Cash provided by operating activities	379,236	419,605	326,762
INVESTING ACTIVITIES			
Capital expenditures	(155,793)	(146,790)	(76,160)
Contributions in aid of construction	8,865	877	4,025
Proceeds from sale of assets	6,882	212	165
Cash used for business combinations, net of cash received	(724,661)	(37,348)	(1,620,727)
Acquisition of intangible asset		(2,000)	(2,000)
Investments in and advances to unconsolidated affiliates	(64,412)	(471,927)	(13,651)
Cash used in investing activities	(929,119)	(656,976)	(1,708,348)
FINANCING ACTIVITIES			
Borrowings under debt agreements	5,934,505	1,926,210	1,968,000
Repayments of debt	(5,808,877)	(2,033,000)	(637,000)
Debt issuance costs	(19,911)	(8,833)	(19,329)
Distributions paid to partners	(438,765)	(309,918)	(214,869)
Distributions paid to minority interests	(6,440)	(8,113)	(3,324)
Contributions from minority interests	9,585	5,949	1,976
Proceeds from issuance of common units	846,077	573,684	180,666
Proceeds from issuance of Class B special units		102,041	
Treasury units reissued (purchased)	8,394	646	(12,788)
Settlement of cash flow hedging financial instruments	19,405	5,354	
Cash provided by financing activities	543,973	254,020	1,263,332
NET CHANGE IN CASH AND CASH EQUIVALENTS	(5,910)	16,649	(118,254)
CASH AND CASH EQUIVALENTS, JANUARY 1	30,466	13,817	132,071
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 24,556	$ 30,466	$ 13,817

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(See Note 10 for Unit History and Detail of Changes in Limited Partners' Equity)
(Dollars in thousands)

	Limited Partners	General Partner	Treasury units	Accum. OCI	Total
Balance, January 1, 2002	$1,141,613	$ 11,531	$ (6,222)		$1,146,922
Net income	84,837	10,663			95,500
Operating leases paid by EPCO	8,943	90			9,033
Cash distributions to partners	(203,013)	(11,856)			(214,869)
Proceeds from issuance of common units (see Note 10)	178,859	1,807			180,666
Treasury unit transactions:					
Purchased			(12,788)		(12,788)
Reissued to satisfy unit options	(1,190)	(12)	1,202		—
Change in fair value of financial instruments recorded as cash flow hedges				$ (3,560)	(3,560)
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	8,913	97			9,010
Other expenses paid by EPCO	433	3			436
Cash distributions to partners	(287,314)	(22,604)			(309,918)
Proceeds from issuance of common units (see Note 10)	567,945	5,739			573,684
Proceeds from issuance of Class B special units (see Note 10)	100,000	2,041			102,041
Restructuring of Enterprise GP ownership in our Operating Partnership (see Note 10)	(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)
Balance, December 31, 2003	$1,683,133	$ 34,349	$(16,519)	$ 4,990	$1,705,953

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY - (Continued)
(See Note 10 for Unit History and Detail of Changes in Limited Partners' Equity)
(Dollars in thousands)

	Limited Partners	General Partner	Treasury units	Deferred Comp.	Accum. OCI	Total
Balance, December 31, 2003	$ 1,683,133	$ 34,349	$ (16,519)		$ 4,990	$ 1,705,953
Net income	231,153	37,108				268,261
Operating leases paid by EPCO	7,551	154				7,705
Cash distributions to partners	(398,247)	(40,518)				(438,765)
Proceeds from issuance of common units (see Note 10)	789,758	16,117				805,875
Proceeds from conversion of Series F2 convertible units to common units (see Note 10)	38,800	792				39,592
Proceeds from exercise of unit options	398	8				406
Value of equity interests granted to complete the GulfTerra Merger (see Note 10)	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 reissued 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

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ENTERPRISE PRODUCTS PARTNERS L.P. is a publicly traded Delaware limited partnership listed on the NYSE symbol "EPD". Unless the context requires otherwise, references to "we," "us," "our," "the Company" or "Enterprise" are intended to mean the consolidated business and operations of Enterprise Products Partners L.P. Certain abbreviated names and other capitalized and industry terms are defined within the glossary of this annual report on Form 10-K.

We were formed in April 1998 to own and operate certain NGL related businesses of EPCO, Inc. ("EPCO," formerly Enterprise Products Company). 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 GP"). We and Enterprise GP are affiliates of EPCO.

On September 30, 2004, we completed the GulfTerra Merger. For additional information regarding this event, please see Note 4.

Certain reclassifications related to restricted cash have been made to the prior years' statements of cash flows to conform to the current year presentation. As a result of the GulfTerra Merger, we have reorganized our business activities into four reportable business segments, as discussed in Note 19.

In May 2002, we completed a two-for-one split of each class of our partnership units. All references to number of units or earnings per unit contained in this document reflect the unit split, unless otherwise indicated.

The consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after elimination of all material intercompany accounts and transactions. The majority-owned subsidiaries are identified based upon the determination that Enterprise possesses a controlling financial interest through direct or indirect ownership of a majority voting interest in the subsidiary. Investments in which we own 20% to 50% and exercise significant influence over operating and financial policies are accounted for using the equity method. Investments in which we own less than 20% are accounted for using the cost method unless we exercise significant influence over operating and financial policies of the investee, in which case the investment is accounted for using the equity method. As a result of recently issued accounting guidance under EITF 03-16, the minimum ownership requirement for an investment organized as a limited liability company ("LLC") to qualify for the equity method of accounting was lowered to between 3% and 5% from the 20% threshold applied to other types of investments. 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. For additional information regarding this change in accounting method, see Note 7.

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 through our investments in Poseidon, Cameron Highway, Deepwater Gateway, Neptune and Nemo. We also have a number of investments in NGL transportation or distribution pipelines such as those owned by Belle Rose and Dixie (prior to our purchasing consolidating interests in Dixie in January and February 2005). 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 see Note 7. For additional information regarding our business segments, please see Note 19.

ASSET RETIREMENT OBLIGATIONS are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development, and/or normal operation. In determining asset retirement obligations, we must identify those legal obligations that we are required to settle as result of existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel.

SFAS No. 143, "*Accounting for Asset Retirement Obligations*," addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and related asset retirement costs. It requires us to record the fair value of an asset retirement obligation (a liability) in the period in which it is incurred. When a liability is recorded, we will capitalize the cost of the liability by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, we will either settle the obligation for its recorded amount or incur a gain or loss upon settlement. We adopted SFAS No. 143 as of January 1, 2003. See Note 6 for information relating to our asset retirement obligations.

CASH FLOWS are computed using the indirect method. For cash flow purposes, we consider all highly liquid investments with an original maturity of less than three months at the date of purchase to be cash equivalents.

CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES represents the combined impact of (1) 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 (2) changing the method in which we account for our investment in VESCO from the cost method to the equity method.

Our BEF subsidiary 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. BEF used the accrue-in-advance method to record cost estimates for such activities; whereas, the Company's other operations used the expense-as-incurred method for their planned major maintenance activities. Our BEF subsidiary changed its accounting method on January 1, 2004 to conform to the Company's accounting for planned major maintenance costs, which better reflects expenses in the period incurred. As such, we believe the change is to a method that is preferable in the circumstances. The cumulative effect of this accounting change for years prior to 2004 resulted in a benefit of $7 million.

EITF 03-16, "*Accounting for Investments in Limited Liability Companies*," requires investments in limited liability companies that have separate ownership accounts for each investor be accounted for similar to limited partnerships under SOP No. 78-9, "*Accounting for Investments in Real Estate Ventures*." Under this new guidance (applicable for the period beginning July 1, 2004), 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 3-5%) than the traditional 20% threshold applied under APB Opinion No. 18, "*The Equity Method of Accounting for Investments in Common Stock*."

Prior to July 1, 2004, 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 that we received cash distributions from them. In accordance with the new accounting guidance in EITF 03-16, we recorded a cumulative effect adjustment equal to the difference between (i) equity earnings from VESCO that would have been recorded using the equity method in periods prior to July 1, 2004 and (ii) the dividend income from VESCO we recorded using the cost method in prior periods. The cumulative effect of this accounting change resulted in a benefit of $3.8 million.

For the periods indicated, the following table shows pro forma net income and earnings per unit amounts assuming the accounting changes noted above were applied retroactively to January 1, 2002. See Note 13 for information regarding the effect of the accounting changes on basic and diluted earnings per unit.

	For the Year Ended December 31,		
	2004	2003	2002
Pro Forma income statement amounts:			
Historical net income	$ 268,261	$ 104,546	$ 95,500
Adjustments to derive pro forma net income:			
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	(8,569)
Record equity in (income) losses from BEF calculated using new method of accounting for major maintenance costs		(31,800)	8,980
Remove cumulative effect of change in accounting principle recorded on January 1, 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 on July 1, 2004	(3,768)		
Remove historical dividend income recorded from VESCO	(2,136)	(5,595)	(4,737)
Record equity earnings from VESCO	2,429	5,133	12,303
Pro forma net income	260,111	103,792	103,477
Enterprise GP interest	(36,945)	(20,708)	(10,743)
Pro forma net income available to limited partners	$ 223,166	$ 83,084	$ 92,734
Pro forma per unit data (basic):			
Historical units outstanding	265,511	199,915	155,454
Per unit data:			
As reported	$ 0.87	$ 0.42	$ 0.55
Pro forma	$ 0.84	$ 0.42	$ 0.60
Pro forma per unit data (diluted):			
Historical units outstanding	266,045	206,367	176,490
Per unit data:			
As reported	$ 0.87	$ 0.41	$ 0.48
Pro forma	$ 0.84	$ 0.40	$ 0.53

DOLLAR AMOUNTS (except per unit amounts) presented in the tabulations within the notes to our financial statements are stated in thousands of dollars, unless otherwise indicated.

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 Notes 10 and 13 for additional information on the capital structure and earnings per unit computation.

ENVIRONMENTAL COSTS for remediation are accrued based on the estimates of known remediation requirements. Such accruals are based on management's estimate of the ultimate costs to remediate the site. Ongoing environmental compliance costs are charged to expense as incurred, and 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 GulfTerra Merger, we have initially estimated an environmental liability of $21 million, which is included in other long-term liabilities on our Consolidated Balance Sheet at December 31, 2004, for remediation costs expected to be incurred over time associated with mercury gas meters. Costs of environmental compliance and monitoring aggregated $1.9 million, $1.6 million and $1.7 million for the years ended December 31, 2004, 2003 and 2002, respectively.

EXCESS COST OVER UNDERLYING EQUITY IN NET ASSETS (or "excess cost") denotes the excess of our cost (or purchase price) over our underlying equity in the net assets of our investees. At December 31, 2004, our investments in Promix, La Porte, Dixie, Neptune, Poseidon, Cameron Highway and Nemo included excess cost. The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities.

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. See Note 7 for a further discussion of the excess cost related to these investments.

EXCHANGES are contractual agreements for 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.

EXIT AND DISPOSAL COSTS are those charges associated with an exit activity that does not involve an entity newly acquired in a business combination or with a disposal activity covered by SFAS No. 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 No. 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. We adopted SFAS No. 146 on January 1, 2003. Our adoption of this standard has had no material impact on our financial statements.

FINANCIAL INSTRUMENTS such as swaps, forward and other contracts to manage the price risks associated with inventories, firm commitments, interest rates and certain anticipated transactions are used by Enterprise. 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 instruments meet those criteria, the instrument's gains and losses offset related results of the hedge item in the income statement for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses on a cash flow hedge are reclassified into earnings when the forecasted transaction occurs. 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 No. 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 is recorded into earnings immediately. See Note 18 for a further discussion of our financial instruments.

GOODWILL represents the excess of amounts we paid for businesses and assets over the respective fair value of the underlying net assets purchased (see Note 8). Since adopting SFAS No. 142, "*Goodwill and Other Intangible Assets*", on January 1, 2002, our goodwill amounts are no longer amortized but are assessed annually for recoverability. In addition, we periodically review the reporting units to which the goodwill amounts relate if impairment indicators are evident. If such indicators are present (i.e., loss of a significant customer, economic obsolescence of plant assets, etc.), the fair value of the reporting unit, including its related goodwill, will be calculated and compared to its combined book value. If the fair value of the reporting unit exceeds its book value, goodwill is not considered impaired and no adjustment to earnings would be required. Should the fair value of the reporting unit (including its goodwill) be less than its book value, a charge to earnings would be recorded to adjust goodwill to its implied fair value. We have not recognized any impairment losses related to our goodwill for any of the periods presented.

INTANGIBLE ASSETS consist primarily of the estimated value assigned to certain customer relationships and certain customer contracts (see Note 8). Our customer relationship intangible assets represent the customer base that GulfTerra and the South Texas midstream assets serve through providing services, including natural gas gathering and processing, NGL fractionation and pipeline transportation. These entities conduct the majority of their business through regular contact and the use of written contracts. The value of these customer relationships are being amortized using expected production curves associated with the underlying resource bases (i.e., the oil and gas reserves associated with the intangible assets). Our estimate of the economic 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 contractual agreements primarily within our natural gas and NGL operations. A contract-based intangible asset with a finite useful life is amortized over its estimated useful life based on the respective contract terms. Our estimate of useful life is also based on a number of factors, including the expected useful life of related assets (i.e., fractionation facility, pipeline, etc.) and the effects of obsolescence, demand, competition and other factors.

INVENTORIES primarily consist of NGL, petrochemical and natural gas volumes and are valued at the lower of average cost or market (see Note 5). Shipping and handling charges directly related to volumes we purchase or to which we take ownership are capitalized as costs of inventory. As these inventories 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 current period operating costs and expenses. Shipping and handling charges for products we sell and deliver to customers are charged to operating costs and expenses as incurred.

Costs and expenses, as shown on our Statements of Consolidated Operations and Comprehensive Income, include costs of sales related to inventories. For the years ended December 31, 2004, 2003 and 2002, such consolidated cost of sales amounts were $7.2 billion, $4.5 billion and $3 billion, respectively.

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 an asset may not be recoverable.

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written-down to estimated fair value in accordance with SFAS No. 144 "*Accounting for the Impairment or Disposal of Long-Lived Assets*." Under SFAS No. 144, an asset shall be tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the 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, an impairment loss equal to the amount the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows.

In order to complete the GulfTerra Merger, the FTC required us to sell our interest in a Mississippi propane storage facility in which we owned a 50% interest. As a result of our determination of this long-lived asset's current market value, we recorded a $4 million non-cash asset impairment charge during the third quarter of 2004, which is reflected a component of operating costs and expenses on our 2004 Statement of Consolidated Operations.

Additionally, during 2003 we recorded a $1.2 million asset impairment charge related to our Petal NGL fractionator. This non-cash amount is a component of operating costs and expenses as shown on our 2003 Statement of Consolidated Operations. The Petal NGL fractionation facility was decommissioned in December 2003 after management decided that this older facility did not fit into our long-range plans due to poor economics of continued operations at the site. We continue to own this facility, the carrying value of which has been adjusted to its fair value of approximately $0.1 million. We did not recognize any impairment losses during 2002.

NATURAL GAS IMBALANCES result when a customer delivers more or less gas into our pipelines than they take out. We generally value our imbalances using a twelve-month moving average of natural gas prices, which we believe is an appropriate assumption to estimate the value of the imbalances upon settlement given that the 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, 2004, our imbalance receivables were $56.7 million and are reflected as a component of accounts receivable. At December 31, 2004, our imbalance payables were $59 million and are reflected as a component of accrued gas payables.

PROPERTY, PLANT AND EQUIPMENT is recorded at its original cost of construction or, upon acquisition, the fair value of the asset acquired. Our property, plant and equipment is generally depreciated using the straight-line method over the asset's estimated useful life. Maintenance, repairs and minor renewals are charged to operations as incurred. The cost of assets retired or sold, together with the related accumulated depreciation, is removed from the accounts. Any gain or loss on disposition is included in operating income.

Additions and improvements to and major renewals of existing assets are capitalized and depreciated using the straight-line method over the estimated useful life of the new equipment or modifications. These expenditures result in a long-term benefit to Enterprise. See Note 6 for additional information regarding our property, plant and equipment.

We use the expense-as-incurred method for our planned major maintenance activities. Prior to January 1, 2004, BEF, which became a majority owned consolidated subsidiary on September 30, 2003, used the accrue-in-advance method for its planned major maintenance costs. On January 1, 2004, BEF elected to change its method of accounting for these costs to the expense-as-incurred method. As a result, our consolidated statement of operations for 2004 reflect the cumulative effect of change in accounting method associated with the removal of BEF's $7.0 million liability for accrued costs for planned future major maintenance activities.

PROVISION FOR INCOME TAXES is primarily applicable to certain federal and/or state tax obligations of our Mid-America and Seminole pipelines. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. See Note 12 for additional information regarding our provision of 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 the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under the partnership agreement.

RESTRICTED CASH includes amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for physical purchase transactions made on the NYMEX exchange. At December 31, 2004 and 2003, cash and cash equivalents includes, $26.2 million and $13.9 million of restricted cash related to these requirements, respectively.

REVENUE is recognized 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. See Note 3 for additional information regarding our revenue recognition process.

When the contracts settle (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), a determination of the necessity of an allowance is made and recorded accordingly. Our allowance for doubtful accounts amount is generally determined as a percentage of revenues for the last twelve months. Our procedure for recording an allowance for doubtful accounts is based on historical experience, financial stability of our customers and levels of credit granted to customers. In addition, we may also increase the allowance account in response to specific identification of customers involved in bankruptcy proceedings and those experiencing financial uncertainties. We routinely review our estimates in this area to ascertain that we have recorded sufficient reserves to cover forecasted losses. Our allowance for doubtful accounts was $24.3 million and $20.4 million at December 31, 2004 and 2003, respectively.

A substantial portion of our revenues are derived from various companies in the domestic natural gas, NGL and petrochemical industry. This concentration could affect our overall exposure to credit risk since these customers might 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.

UNIT OPTION PLAN ACCOUNTING is based on the intrinsic-value method described in APB No. 25, "*Accounting for Stock Issued to Employees.*" Under this method, no compensation expense is recorded related to options granted when the exercise price is equal to or greater than the market price of the underlying equity on the date of grant. In accordance with SFAS No. 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 No. 123, "Accounting for Stock-Based Compensation" had been used instead of the intrinsic-value of APB No. 25. The effects of applying SFAS No. 123 in the following pro forma disclosure may not be indicative of future amounts as additional awards in future years are anticipated. The following table shows the pro forma effects for the periods indicated.

	For Year Ended December 31,		
	2004	2003	2002
Historical net income	$268,261	$104,546	$ 95,500
Additional unit option-based compensation expense estimated using fair value-based method	(932)	(1,107)	(2,077)
Pro forma net income	267,329	103,439	93,423
Less incentive earnings allocations to Enterprise GP	(32,391)	(19,699)	(9,806)
Pro forma net income after incentive earnings allocation	234,938	83,740	83,617
Multiplied by Enterprise GP ownership interest	2.0%	1.2%	1.0%
Standard earnings allocation to Enterprise GP	$ 4,699	$ 1,005	$ 836
Incentive earnings allocation to Enterprise GP	$ 32,391	$ 19,699	$ 9,806
Standard earnings allocation to Enterprise GP	4,699	1,005	836
Enterprise GP interest in pro forma net income	$ 37,090	$ 20,704	$ 10,642
Pro forma net income	$267,329	$103,439	$ 93,423
Less Enterprise GP interest in pro forma net income	(37,090)	(20,704)	(10,642)
Pro forma net income available to limited partners	$230,239	$ 82,735	$ 82,781
Basic earnings per unit, net of Enterprise GP interest:			
Historical units outstanding	265,511	199,915	155,454
As reported	$ 0.87	$ 0.42	$ 0.55
Pro forma	$ 0.87	$ 0.41	$ 0.53
Diluted earnings per unit, net of Enterprise GP interest:			
Historical units outstanding	266,045	206,367	176,490
As reported	$ 0.87	$ 0.41	$ 0.48
Pro forma	$ 0.87	$ 0.40	$ 0.47

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions:

	2004	2003	2002
Expected life of options	7 years	7 years	7 years
Risk-free interest rate	3.99%	3.79%	3.10%
Expected dividend yield	8.78%	9.12%	5.65%
Expected Unit price volatility	29%	29%	25%

USE OF ESTIMATES AND ASSUMPTIONS by management that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period are required for the preparation of financial statements in conformity with accounting principles generally accepted in the United States of America. Our actual results could differ from these estimates.

2. RECENT ACCOUNTING DEVELOPMENTS

FIN 46, "*Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51*." This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 (as amended by FIN 46R) in 2003 has had no material effect on our consolidated financial statements. Due to the complexity of FIN 46 (as amended by FIN 46R and interpreted), the FASB is continuing to provide guidance regarding implementation issues. Since this guidance is still continuing, our conclusions regarding the application of this guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of FIN 46.

EITF 03-06, "*Participating Securities and the Two-Class Method under SFAS No. 128*." This accounting guidance, which is applicable for the period beginning April 1, 2004, requires the two-class method for calculating earnings per share for certain securities that are considered to participate in earnings with common shareholders. Under the two-class method, distributions to equity owners are subtracted from earnings, and any remaining earnings would be allocated to the various classes of owners in proportion to their right to receive distributions as if those earnings had been distributed. The total distributions to each class of owner plus the amount allocated to each class would be used to compute earnings per unit for that class. Since our distributions to owners exceeded earnings during the periods presented, as has historically been the case, the two-class method did not produce any change from the way we have traditionally computed earnings per unit. As a result, our adoption of this standard had no effect on our earnings per unit calculations.

SFAS No. 151, "Inventory Costs — an Amendment of ARB No. 43, Chapter 4." This accounting guidance, which is applicable for fiscal years beginning after June 15, 2005, amends ARB No. 43, Chapter 4, to clarify that abnormal amounts of idle facility expense, freight, handling costs and wasted materials (spoilage) should be recognized as current period charges. It also requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. We do not expect the adoption of SFAS No. 151 to have a material impact on our financial position, results of operations or cash flows.

SFAS No. 123(R), "Share-Based Payment." This accounting guidance, which is applicable for the first interim or annual reporting period beginning after June 15, 2005, replaces SFAS No. 123, "*Accounting for Stock-Based Compensation*" and supersedes APB No. 25, "*Accounting for Stock Issued to Employees*." This Statement eliminates the ability to account for share-based compensation transactions using APB No. 25, and generally requires instead that such transactions be accounted for using a fair-value-based method.

This statement requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with limited exceptions). That cost will be recognized over the period during which an employee is required to provide service in exchange for the award — the requisite service period (usually the vesting period). No compensation cost is recognized for equity instruments for which employees do not render the requisite service. Employee share purchase plans will not result in recognition of compensation cost if certain conditions are met; those conditions are much the same as the related conditions in SFAS No. 123.

A public entity will initially measure the cost of employee services received in exchange for an award of liability instruments based on its current fair value; the fair value of that award will be remeasured subsequently at each reporting date through the settlement date. Changes in fair value during the requisite service period will be recognized as compensation cost over that period.

The grant-date fair value of employee share options and similar instruments will be estimated using option-pricing models adjusted for the unique characteristics of those instruments (unless observable market prices for the same or similar instruments are available). If an equity award is modified after the grant date, incremental compensation cost will be recognized in an amount equal to the excess of the fair value of the modified award over the fair value of the original award immediately before the modification.

We are continuing to evaluate the provisions of SFAS No. 123(R) and will fully adopt the standard during 2005 within the prescribed time periods. Upon the required effective date, we will apply this statement using a modified version of prospective application as described in the standard.

3. REVENUE RECOGNITION

The following summarizes our consolidated revenue recognition policies by business segment, which are generally organized according to the type of services rendered and products produced and/or sold:

Offshore Pipelines & Services. Revenues from our offshore natural gas pipelines are derived from fee-based contracts and are typically based on transportation fees per unit of volume (typically in MMBtus) transported multiplied by the volume delivered. Revenues are recognized when volumes have been physically delivered for the customer through the pipeline.

Revenues from the majority of our offshore crude oil pipelines are derived from purchase and sale arrangements whereby we purchase oil from shippers at various receipt points on 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 index-based price. The net revenue from these arrangements are based on the price differential (difference between the purchase and sales price) per unit of volume (typically in barrels) multiplied by the volume delivered. Revenues associated with these purchase and sale arrangements are recorded as net revenue and are recognized when we complete the delivery of crude oil to the purchaser. Revenues from some of our offshore crude oil pipelines are based upon a gathering fee per unit of volume (typically in barrels) multiplied by the volume delivered. Revenues from the gathering fees we charge 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.

Under our platform services contracts, there are typically two components of revenues, a demand fee which is typically a fixed-fee charged to a customer using our platform services regardless of the volume the customer delivers to the platform, and a commodity charge which is typically a fixed-fee per MMcf of natural gas or barrel of crude oil, whichever the case may be, multiplied by the volume delivered to our platform by the customer. 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.

Onshore Natural Gas Pipelines & Services. Revenues from some of our onshore natural gas pipelines are derived from fee-based contracts and are typically based upon a transportation fee per unit of volume (generally in MMBtus) transported multiplied by the volume delivered. The transportation fee is generally contractual or as regulated by various governmental agencies, including the FERC. Revenues associated with these fee-based contracts are recognized when volumes have been physically delivered to our customer through the pipeline. Additionally, 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 natural gas 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, fixed monthly demand payments, which are associated with storage capacity reservation and paid regardless of the customer's usage of the storage facilities, and storage fees per unit of volume stored at the facilities. Revenues from demand payments are recognized throughout the period in which the capacity is reserved by the customer, and revenues from storage fees associated with volumes stored at our facilities are recognized in the period the services are provided.

NGL Pipelines & Services. In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, fee-based contracts, hybrid contracts (mixed percent-of-liquids and fee-based) and keepwhole contracts. The most significant contract affecting our natural gas processing business is the Shell agreement, which is a margin-band arrangement, which grants us the right to process Shell's current and future production within state and federal waters of the Gulf of Mexico. 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. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer.

Our NGL marketing activities within this segment use product sales contracts with various customers to sell and deliver NGLs as a result of our margin-band, keepwhole and percent-of-liquids arrangements and those it purchases from third parties in the open market. These NGL sales contracts may include forward product sales contracts from time-to-time. Revenues from NGL sales contracts are recognized and recorded upon the delivery of the NGL products to our customers. Pricing for these sales contracts is based upon market-related prices and can include pricing differentials due to factors such as differing delivery locations.

Under our NGL transportation contracts, revenue is recognized when volumes have been physically delivered to our customer through the pipeline. Revenue from these contracts is generally based upon a fixed fee per gallon of liquids transported, multiplied by the volume delivered. The fixed fee is generally contractual or as required by various 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 NGL or petrochemical 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 terminaling contracts (applicable to our import and export operations) are recorded when services have been performed. In our export operations, we record revenues related to demand fees collected from exporters and shippers in the event they contract for use of our facilities and later fail to do so. The demand fees are contractual and vary by agreement. We recognize revenue from contractual demand fees after the exporter or shipper fails to utilize our facilities as required by contract.

We also enter into NGL fractionation fee-based arrangements and NGL fractionation percent-of-liquids contracts. Under our fee-based arrangements, we recognize revenue upon completion of all contract services and obligations. These fee-based arrangements typically include a base-processing fee (typically in cents per gallon) subject to adjustment for changes in certain of our fractionation expenses, including natural gas fuel costs. For some of our NGL fractionation facilities, we utilize percent-of-liquids contracts. A percent-of-liquids processing contract allows us to retain a contractually determined percentage of NGL products fractionated for our customer in lieu of collecting a cash-tolling fee per gallon.

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 upon completion of all contract processing services and obligations. 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 fractionation and isomerization operations.

In our petrochemical product sales contracts, we recognize revenue when the products have been delivered to the customer. Pricing for sales contracts is based upon market-related prices as determined by the individual agreements.

Consolidated revenues compared to segment revenues. Segment revenues include intersegment and intrasegment revenues, 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. See Note 19 for additional information regarding intersegment and intrasegment revenues and a reconciliation of total segment revenues to total consolidated revenues.

4. BUSINESS COMBINATIONS

GulfTerra Merger

On September 30, 2004, Enterprise and GulfTerra completed the merger of GulfTerra with a wholly owned subsidiary of Enterprise. Additionally, Enterprise completed certain other transactions related to the merger, including receipt of Enterprise GP's contribution of a 50% membership interest in GulfTerra GP, which was acquired by Enterprise GP from El Paso, and the purchase of certain midstream energy assets located in South Texas from El Paso. The aggregate value of the total consideration Enterprise paid or issued to complete the GulfTerra Merger was approximately $4 billion.

Since the GulfTerra Merger closed on September 30, 2004, our Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2004, includes three months of results of operations from the GulfTerra assets. The effective closing date of our purchase of the South Texas midstream assets was September 1, 2004. As a result, our Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2004, includes four months of results of operations from the South Texas midstream assets.

As a result of the GulfTerra Merger, GulfTerra and GulfTerra GP became wholly owned subsidiaries of Enterprise on September 30, 2004. On October 1, 2004, we contributed our ownership interests in GulfTerra and GulfTerra GP to our Operating Partnership, which resulted in GulfTerra and GulfTerra GP becoming wholly owned subsidiaries of the Operating Partnership.

Formed in 1993, GulfTerra manages a balanced, diversified portfolio of interests and assets relating to the midstream energy sector, which involves gathering, transporting, separating, processing, fractionating and storing natural gas, oil and NGLs. GulfTerra's interests and assets included (i) offshore oil and natural gas pipelines, platforms, processing facilities and other energy infrastructure in the Gulf of Mexico, primarily offshore Louisiana and Texas; (ii) onshore natural gas pipelines and processing facilities in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas; (iii) onshore NGL pipelines and fractionation facilities in Texas; and (iv) onshore natural gas and NGL storage facilities in Louisiana, Mississippi and Texas.

The South Texas midstream assets consisted of nine natural gas processing plants with a combined capacity of 1.9 Bcf/d, a 294-mile natural gas gathering system, a natural gas treating facility with a capacity of 150 MMcf/d and a small NGL pipeline.

The GulfTerra Merger transactions

The GulfTerra Merger occurred in several interrelated transactions as described below.

- *Step One*. On December 15, 2003, Enterprise purchased a 50% membership interest in GulfTerra GP from El Paso for $425 million in cash. GulfTerra GP owns a 1% general partner interest in GulfTerra. Prior to completion of the GulfTerra Merger, Enterprise accounted for its investment in GulfTerra GP using the equity method of accounting. The $425 million in funds required to complete Step One were borrowed under an Interim Term Loan and our pre-merger revolving credit facilities. This amount was fully repaid with the net proceeds from equity offerings completed during 2004. See Note 9 for additional information regarding changes in our debt obligations since December 31, 2003.

- *Step Two*. On September 30, 2004, the GulfTerra Merger was consummated and GulfTerra and GulfTerra GP became wholly owned subsidiaries of Enterprise. 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 GP acquired El Paso's remaining 50% membership interest in GulfTerra GP for $370 million in cash paid to El Paso and the issuance of a 9.9% membership interest in Enterprise GP to El Paso. Subsequently, Enterprise 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 GP borrowed the foregoing $370 million from Dan Duncan LLC (which owns a membership interest in Enterprise GP), which obtained the funds from a loan from EPCO (which indirectly owns the remaining membership interests in Enterprise GP).

  - Immediately prior to closing the GulfTerra Merger, Enterprise 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 (7,433,425 of which were owned by El Paso) were converted into 104,549,823 Enterprise common units (13,454,499 of which are held by El Paso) at the time of the consummation of the GulfTerra Merger.

- *Step Three*. Immediately after Step Two was completed, Enterprise acquired certain South Texas midstream assets from El Paso for $155.3 million in cash. Pursuant to written agreements, our purchase of the South Texas midstream assets was effective September 1, 2004.

In connection with the closing of the GulfTerra Merger, on September 30, 2004, our Operating Partnership borrowed an aggregate $2.8 billion under its new revolving credit facilities in order to fund its cash payment obligations under Step Two and Step Three of the GulfTerra Merger and related transactions, including the tender offers for GulfTerra's outstanding senior and senior subordinated notes. See Note 9 for a description of these new borrowing and debt-related transactions.

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The total consideration paid or granted for the GulfTerra Merger is summarized below:

Step One transaction:	
Cash payment by Enterprise 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 Enterprise 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 Enterprise common units issued in exchange for remaining GulfTerra common units (see Note 10)	2,445,420
Fair value of other Enterprise equity interests granted for unit awards and Series F2 convertible units	4,004
Fair value of receivable from El Paso for transition support payments (2)	(40,313)
Transaction fees and other direct costs incurred by Enterprise as a result of the GulfTerra Merger(3)	24,032
Total Step Two consideration	3,394,490
Total Step One and Step Two consideration	3,819,490
Step Three transaction:	
Purchase of South Texas midstream assets from El Paso	155,277
Total consideration for Steps One through Three	$ 3,974,767

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(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 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 GP granted to El Paso in this transaction from the 50% membership interest in GulfTerra GP that Enterprise 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 Enterprise to purchase its initial 50% non-voting membership interest in GulfTerra GP in December 2003. The contribution of this 50% membership interest to Enterprise is allocated for financial reporting purposes to Enterprise's 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 Enterprise 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 Enterprise 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 has been discounted to fair value and recorded as a reduction in the purchase consideration for GulfTerra. As December 31, 2004, the fair value of the current portion and non-current portion of this contract-based receivable was $17.2 million and $23.1 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, 2004.

(3) As a result of the GulfTerra Merger, Enterprise incurred expenses of approximately $24 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 Enterprise over the course of the GulfTerra Merger transactions. This amount also includes $3.4 million of involuntary severance costs.

In connection with the GulfTerra Merger, we are required under a consent decree to sell our 50% interest in Starfish, which owns the Stingray natural gas pipeline and related gathering pipelines and dehydration and other facilities located in south Louisiana and the Gulf of Mexico offshore Louisiana. In January 2005, we entered into a contract with a third party to sell this investment for approximately $41.2 million. We expect to close this sale during the first quarter of 2005. The sale requires FTC approval under the terms of the consent decree relating to the GulfTerra Merger and is subject to other customary closing conditions. Additionally, under the same consent decree, we were required to sell our undivided 50% interest in a Mississippi propane storage facility by December 31, 2004. We sold our interest in this facility during the fourth quarter of 2004.

Other business combinations and asset acquisitions completed during 2004

During 2004, we also acquired an additional 16.7% interest in Tri-States; an additional 10% interest in Seminole; the remaining 33.3% ownership interest in BEF; and certain assets located in Morgan’s Point, Texas.

Acquisition of 16.7% interest in Tri-States. On April 1, 2004, we acquired an additional 16.7% membership interest in Tri-States, which owns an NGL pipeline located along the Mississippi, Alabama and Louisiana Gulf Coast. This system, in conjunction with the Wilprise and Belle Rose NGL pipelines, transport mixed NGLs to the BRF, Norco and Promix NGL fractionators located in south Louisiana. Due to this acquisition, our ownership interest in Tri-States increased to 66.7% and Tri-States became a majority-owned consolidated subsidiary of ours on April 1, 2004. Previously, Tri-States was accounted for as an equity method unconsolidated affiliate.

Acquisition of 10% interest in Seminole. On May 31, 2004, we acquired an additional 10% interest in Seminole, which owns a regulated 1,281-mile pipeline that transports mixed NGLs and NGL products from the Hobbs hub on the Texas-New Mexico border and the Permian Basin area to southeast Texas. As a result of this acquisition, our ownership interest in Seminole increased to 88.4%. The Seminole pipeline is interconnected with our Mid-America pipeline system at the Hobbs hub. The primary source of throughput for Seminole is volume originating from the Mid-America system.

Acquisition of remaining 33.3% interest in BEF. On September 1, 2004, we acquired the remaining 33.3% ownership interest in BEF, which owns a facility that produces octane additives such as MTBE (a motor gasoline additive that enhances octane and is used in reformulated gasoline). As a result of this acquisition, BEF became a wholly owned subsidiary of ours.

Acquisition of Morgan’s Point assets. On December 13, 2004, we acquired certain assets located in Morgan’s Point, Texas from Valero. The assets acquired primarily include an octane enhancement facility, a butane isomerization facility, a barge dock and NGL and petrochemical pipelines.

Allocation of purchase price of 2004 business combinations

The GulfTerra Merger transactions and our other business and asset acquisitions completed during 2004 were recorded using the purchase method of accounting. Purchase accounting requires us to allocate the cost of a business combination to the assets acquired and liabilities assumed based on their estimated fair values. Enterprise engaged an independent third-party business valuation expert to assess the fair values of the tangible and intangible assets of GulfTerra, the South Texas midstream assets, and those acquired in the Morgan’s Point transaction. This information will assist management in the development of a definitive allocation of the overall purchase price of the GulfTerra Merger transactions. Management independently developed the fair value estimates for the other 2004 business acquisitions using recognized business valuation techniques.

The preliminary fair values shown in the following table are estimates based on information available to management at December 31, 2004. The valuation estimates shown below could change due to this recent transaction and the refinement of our estimates.

	Merger-Related Transactions			
	Step Two of GulfTerra Merger	Step Three Purchase of South Texas Midstream Assets	Other 2004 Acquisitions	Total
Purchase price allocation:				
Assets acquired in business combination:				
Current assets, including cash of $40,453	$ 198,347	$ 7,614	$ 10,374	$ 216,335
Property, plant and equipment, net	4,601,390	112,830	92,721	4,806,941
Investments in and advances to unconsolidated affiliates	202,672		(42,597)	160,075
Intangible assets	705,459	37,802	1,092	744,353
Other assets	26,881			26,881
Total assets acquired	5,734,749	158,246	61,590	5,954,585
Liabilities assumed in business combination:				
Current liabilities	(228,566)	(2,969)	(2,329)	(233,864)
Long-term debt, including current maturities	(2,015,583)			(2,015,583)
Other long-term liabilities	(47,880)			(47,880)
Minority interest			26,590	26,590
Total liabilities assumed	(2,292,029)	(2,969)	24,261	(2,270,737)
Total assets acquired less liabilities assumed	3,442,720	155,277	85,851	3,683,848
Total consideration given	3,819,490	155,277	85,851	4,060,618
Remaining Goodwill	$ 376,770	$ —	$ —	$ 376,770

As a result of the preliminary purchase price allocation for Steps Two and Three of the GulfTerra Merger, we recorded $744.4 million of amortizable intangible assets, primarily those related to customer relationships and contracts. The remaining preliminary amount represents goodwill of $376.8 million associated with our view of the future results from GulfTerra's operations, based on the strategic location of GulfTerra's assets as well as their industry relationships. For additional information regarding these intangible assets and goodwill, see Note 8. For the recent GulfTerra Merger and the related South Texas midstream assets, the allocation of the purchase price to the estimated fair values of assets and liabilities is based, in part, upon assistance from an independent third party business valuation expert. In addition, the Morgan's Point allocation (which is a component of "Other 2004 Acquisitions" as shown in the preceding table), is preliminary. Such preliminary values are subject to final valuation reports and additional information.

Pro forma financial information

The following table presents selected unaudited pro forma financial information incorporating the historical (pre-merger) results of GulfTerra, the South Texas midstream assets and our other business acquisitions. Since the GulfTerra Merger closed on 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 was September 1, 2004. As a result, our Statements of Consolidated Operations and Comprehensive Income for the year ended December 31, 2004 include four months of results of operations from the South Texas midstream assets. The results of operations of our other business acquisitions are also included in our Statements of Consolidated Operations from the date of acquisition.

The following pro forma information has been prepared as if the GulfTerra Merger and our other business combination transactions had been completed on January 1, 2003 as opposed to the actual dates that these acquisitions occurred. The pro forma information is based upon data currently available and includes certain estimates and assumptions made by management. As a result, this pro forma information is not necessarily indicative of our financial results had the transactions actually occurred on this date. Likewise, the following unaudited pro forma financial information is not necessarily indicative of our future financial results (dollars in millions, except per unit amounts).

	For the Year Ended December 31,	
	2004	2003
Pro forma earnings data:		
Revenues	$ 9,617.0	$ 7,298.1
Costs and expenses	$ 9,066.0	$ 6,857.5
Operating income	$ 579.4	$ 366.7
Income before extraordinary items	$ 315.2	$ 72.8
Net income	$ 315.2	$ 72.8
Pro forma net income	$ 315.2	$ 72.8
Less incentive earnings allocations to Enterprise GP	(44.0)	(34.9)
Pro forma net income after incentive earnings allocation	271.2	37.9
Multiplied by Enterprise GP ownership interest	2.0%	2.0%
Standard earnings allocation to Enterprise GP	$ 5.4	$ 0.8
Incentive earnings allocation to Enterprise GP	$ 44.0	$ 34.9
Standard earnings allocation to Enterprise GP	5.4	0.8
Enterprise GP interest in pro forma net income	$ 49.4	$ 35.7
Pro forma net income	$ 315.2	$ 72.8
Less Enterprise GP interest in pro forma net income	(49.4)	(35.7)
Pro forma net income available to limited partners	$ 265.8	$ 37.1
Basic earnings per unit, net of Enterprise GP interest:		
As reported basic units outstanding	265.5	199.9
Pro forma basic units outstanding	396.9	350.3
As reported basic net income per unit	$ 0.83	$ 0.42
Pro forma basic net income per unit	$ 0.67	$ 0.11
Diluted earnings per unit, net of Enterprise GP interest:		
As reported pro forma units outstanding	266.0	206.4
Pro forma diluted units outstanding	397.4	356.8
As reported diluted net income per unit	$ 0.83	$ 0.41
Pro forma diluted net income per unit	$ 0.67	$ 0.10

The pro forma net income effect for 2003 was reduced by $45 million to include the non-cash asset impairment charge recorded by BEF. For additional information regarding this charge made during 2003, see Note 7.

5. INVENTORIES

Our inventories consisted of the following at the dates indicated:

	December 31, 2004	December 31, 2003
Working inventory	$ 171,485	$ 135,451
Forward-sales inventory	17,534	14,710
Inventory	$ 189,019	$ 150,161

A general description of our inventories is as follows:

- Our regular trade (or "working") inventory is 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 OPIS and 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.

In general, our inventory values reflect amounts we have paid for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection and demurrage charges and other handling and processing costs. In those instances where we take ownership of inventory volumes through percent-of-liquids and similar arrangements (as opposed to actually purchasing volumes for cash from third parties, see Note 3), these volumes are valued at market-related prices during the month in which they are acquired. Like the third-party purchases described above, we inventory the various ancillary costs such as freight-in and other handling and processing amounts associated with owned volumes obtained through our in-kind and similar 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 in the period they are recognized and generally affect our segment operating results in the following manner:

- NGL inventory write-downs are recorded as a cost of the Processing segment's NGL marketing activities;

- Natural gas inventory write downs are recorded as a cost of the Pipeline segment's Acadian Gas operations; and

- Petrochemical inventory write downs are recorded as a cost of the Fractionation segment's petrochemical marketing activities or as a cost of the Octane Enhancement segment's MTBE operations, as applicable.

For the years ended December 31, 2004, 2003 and 2002, we recognized LCM adjustments of approximately $9.4 million, $16.9 million and $6.3 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 in some cases, offset). See Note 18 for a description of our commodity hedging activities.

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6. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment and accumulated depreciation were as follows at the dates indicated:

	Estimated Useful Life in Years	At December 31, 2004	2003
Plants and pipelines (1)	5-35(5)	$7,691,197	$3,214,463
Underground and other storage facilities (2)	5-35(6)	531,394	288,199
Platforms and facilities (3)	23-31	162,645	
Transportation equipment (4)	3-10	7,240	5,676
Land		29,142	23,447
Construction in progress		230,375	74,431
Total		8,651,993	3,606,216
Less accumulated depreciation		820,526	642,711
Property, plant and equipment, net		$7,831,467	$2,963,505

(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, 2004, 2003 and 2002 was $161 million, $101 million and $72.5 million, respectively. The significant portion of the year-to-year increase in depreciation expense is attributable to acquisitions we completed during each period. The year-to-year increase in depreciation expense for 2004 and 2003 is primarily due to the property, plant and equipment assets we acquired in the GulfTerra Merger, which were recorded at their preliminary fair values upon completion of the GulfTerra Merger at September 30, 2004 (see Note 4).

Capitalized interest on our construction projects for the years ended December 31, 2004, 2003 and 2002 was $2.8 million, $1.6 million and $1.1 million, respectively.

Asset retirement obligations. SFAS No. 143 establishes accounting standards for the recognition and measurement of an ARO liability and the associated asset retirement cost. As a result of the GulfTerra Merger, we assumed AROs associated with the future retirement obligations for certain limited offshore assets located in the Gulf of Mexico. The aggregate $6.2 million liability associated with this ARO is a component of “Other Long-Term Liabilities” on our Consolidated Balance Sheet as of December 31, 2004.

In addition to the obligations we assumed in the GulfTerra Merger, we have also identified ARO liabilities in our other operational areas. These include ARO liabilities related to (i) right-of-way easements over property not owned by us and (ii) regulatory requirements triggered by the abandonment or retirement of certain currently operated facilities. As a result of our analysis of these identified AROs, we were not required to recognize such potential liabilities. Our rights under the easements are renewable and only require retirement action upon nonrenewal of the easement agreements. We currently expect to renew all such easement agreements and to use these properties for the foreseeable future. Should we decide not to renew these right-of-way agreements, an ARO liability would be recorded at that time. We also identified potential ARO liabilities arising from regulatory requirements related to the future abandonment or retirement of certain currently operated facilities. At present, we currently have no intention or legal obligation to abandon or retire such facilities. An ARO liability would be recorded if future abandonment or retirement of such facilities occurred.

Certain of our unconsolidated affiliates, Deepwater Gateway, Neptune, Nemo, and Starfish, had recorded ARO's at December 31, 2004 relating to regulatory requirements. These amounts are immaterial to our financial statements and had a negligible effect on our equity earnings from these investments during 2004.

7. INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES

We own interests in a number of related businesses that are accounted for using the equity method. In general, we use the equity method of accounting for an investment in which we own 20% to 50% of its outstanding ownership interests and exercise significant influence over its operating and financial policies. We do not exercise management control over our equity or cost method investees. As a result of recently issued accounting guidance under EITF 03-16 (see Note 1), the minimum ownership requirement for an investment organized as a limited liability company (or "LLC") to qualify for the equity method of accounting was lowered to between 3% and 5% from the 20% threshold applied to other types of investments.

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. Our VESCO investment consists of a 13.1% interest in a LLC that owns a natural gas processing plant, NGL fractionation facilities, storage assets and gas gathering pipelines located in south Louisiana. For additional information regarding this change in accounting method, see Note 1.

Our investments in and advances to these unconsolidated affiliates are grouped in the following table according to the business segment to which they relate. For a general discussion of our business segments, see Note 19.

	Ownership Percentage at December 31, 2004	Investments in and advances to Unconsolidated Affiliates at December 31, 2004	Investments in and advances to Unconsolidated Affiliates at December 31, 2003
Offshore Pipeline & Services:			
Poseidon (1)	36.0%	$ 63,944	
Cameron Highway (1)	50.0%	114,354	
Deepwater Gateway (1)	50.0%	56,527	
Offshore pipeline investments (2)	Various	84,638	$ 127,605
Onshore Natural Gas Pipeline & Services:			
Evangeline	49.5%	2,810	2,519
Coyote (1)	50.0%	2,441	
NGL Pipeline & Services:			
Dixie	19.9%	32,514	35,988
VESCO	13.1%	38,437	33,000
Belle Rose	41.7%	10,172	10,780
Promix	50.0%	65,748	38,903
BRF	32.3%	27,012	27,892
Tri-States (3)			44,119
Petrochemical Services:			
BRPC	30.0%	15,617	16,584
La Porte	50.0%	4,950	5,422
Other:			
GulfTerra GP (4)			424,947
Total		$ 519,164	$ 767,759

(1) Our ownership interest in these investments was acquired in connection with the GulfTerra Merger on September 30, 2004.

(2) Reflects our collective investment in Neptune, Nemo and Starfish. In connection with the GulfTerra Merger, we are required under a consent decree published for comment by the FTC on September 30, 2004 to sell our 50% ownership interest in Starfish. The carrying value of our investment in Starfish was reclassified from “Investments in and Advances to Unconsolidated Affiliates” to “Assets Held for Sale” on our Consolidated Balance Sheet at December 31, 2004.

(3) We acquired an additional 16.7% ownership interest in Tri-States in April 2004. As a result of this acquisition, Tri-States became a consolidated subsidiary.

(4) In connection with the GulfTerra Merger (see Note 4), GulfTerra GP became a wholly owned consolidated subsidiary 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.

On occasion, the price we pay to acquire an investment exceeds the underlying historical net assets (i.e., the underlying equity account balances on the books of the investee) that we purchase. These excess cost amounts are a component of our investments in and advances to unconsolidated affiliates. At December 31, 2004, our investments in Promix, La Porte, Dixie, Neptune, Poseidon, Cameron Highway and Nemo included excess cost. An analysis of each of these investments at the time of purchase indicated that such excess cost amounts were attributable to either (i) an increase in the fair value of the tangible assets owned by each entity over the investee’s historical carrying values or (ii) it was unattributable to other specific assets (including intangible assets) and was deemed to be goodwill. To the extent that we attribute an excess cost amount to tangible or intangible assets, we amortize these amounts 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, 2004, excess cost amounts included in our investments in and advances to unconsolidated affiliates totaled $83.6 million, of which $74.3 million was attributed to tangible assets and the remainder to goodwill. Amortization of our excess cost amounts attributed to tangible assets was $1.9 million, $1.6 million, and $1.6 million during 2004, 2003 and 2002, respectively.

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

	For the Year Ended December 31,		
	2004	2003	2002
Offshore Pipeline & Services:			
Poseidon	$ 2,509		
Cameron Highway	(461)		
Deepwater Gateway	3,562		
Offshore pipeline investments (1)	3,249	$ 5,561	$ 10,534
Onshore Natural Gas Pipeline & Services:			
Coyote	541		
Evangeline	231	131	(58)
NGL Pipelines & Services:			
Dixie	1,273	1,323	1,231
VESCO	6,132		
Belle Rose	(402)	(55)	203
Promix	859	2,106	3,936
BRF	2,190	832	2,427
Tri-States (2)	(154)	1,542	1,959
Wilprise (2)		276	948
EPIK (2)		1,818	4,688
Petrochemical Services:			
BRPC	1,943	1,198	997
La Porte	(710)	(698)	(559)
BEF (2)		(27,864)	8,569
OTC (2)		(77)	378
Other:			
Gulf Terra GP (3)	32,025	(53)	
Total	$ 52,787	$ (13,960)	$ 35,253

(1) Reflects combined equity earnings from Neptune, Nemo and Starfish. In connection with the GulfTerra Merger, we are required under a consent decree published for comment by the FTC on September 30, 2004 to sell our 50% interest in Starfish.

(2) 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; and Tri-States, April 2004.

(3) In connection with the GulfTerra Merger (see Note 4), GulfTerra GP became a wholly owned consolidated subsidiary 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.

Offshore Pipelines & Services segment

At December 31, 2004, our Offshore Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

- *Poseidon Oil Pipeline Company, L.L.C.* ("Poseidon") – a 36% interest in Poseidon, which owns a crude oil pipeline extending from the Gulf of Mexico to onshore Louisiana. Poseidon completed construction of its Front Runner oil pipeline in the third quarter of 2004 and received its first volumes from this new oil pipeline in January 2005. This new oil pipeline connects the Front Runner platform in the Gulf of Mexico with Poseidon's existing system.

- *Cameron Highway Oil Pipeline Company* ("Cameron Highway") – a 50% interest in Cameron Highway, which owns a recently constructed crude oil pipeline system that connects various designated crude oil receipt points extending from Ship Shoal Block 332 in the Gulf of Mexico to onshore delivery points located in the state of Texas. We anticipate that operations will commence on this pipeline system in early 2005.

- *Deepwater Gateway, L.L.C.* (“Deepwater Gateway”) – a 50% interest in Deepwater Gateway, which owns the Marco Polo tension-leg platform. The Marco Polo tension-leg platform is operated by Anadarko Petroleum Corporation (“Anadarko”) and processes oil and natural gas from Anadarko’s Marco Polo Field discovery located at Green Canyon Block 608 in the Gulf of Mexico. The Marco Polo tension-leg platform went into service during the third quarter of 2004.

- *Offshore pipeline investments* - our collective investment in Neptune Pipeline Company, L.L.C. (“Neptune”), Nemo Gathering Company, LLC (“Nemo”) and Starfish Pipeline Company, LLC (“Starfish”). We own a 25.7% interest in Neptune, which owns the Manta Ray and Nautilus natural gas pipeline systems located in the Gulf of Mexico offshore Louisiana. In addition, we own a 33.9% interest in Nemo, which owns the Nemo natural gas pipeline located in the Gulf of Mexico offshore Louisiana. This category also includes our 50% interest in Starfish, which owns the Stingray and Triton natural gas pipeline and related dehydration and other facilities located in south Louisiana and the Gulf of Mexico. In connection with the GulfTerra Merger, we are required under a consent decree published for comment by the FTC on September 30, 2004 to sell our 50% interest in Starfish. We are required to sell this investment by March 31, 2005. In January 2005, we entered into a contract with a third party to sell this investment for approximately $42.1 million. We expect this sale to close during the first quarter of 2005. The sale requires FTC approval under the terms of the consent decree and is subject to other customary closing conditions.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment’s unconsolidated affiliates are summarized below.

	At December 31, 2004	At December 31, 2003
BALANCE SHEET DATA:		
Current assets	$ 79,196	$ 93,277
Property, plant and equipment, net	712,182	711,853
Other assets	528,443	277,205
Total assets	$ 1,319,821	$ 1,082,335
Current liabilities	$ 71,758	$ 64,585
Other liabilities	526,990	404,170
Combined equity	721,073	613,580
Total liabilities and combined equity	$ 1,319,821	$ 1,082,335

	For Year Ended December 31, 2004	2003	2002
INCOME STATEMENT DATA:			
Revenues	$ 88,603	$ 76,168	$ 90,924
Operating income	46,938	39,658	54,752
Net income	38,473	33,700	73,509

Onshore Natural Gas Pipelines & Services segment

At December 31, 2004, our Onshore Natural Gas Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

- *Evangeline Gas Pipeline Company, L.P.* and *Evangeline Gas Corp.* (collectively, “Evangeline”) – an approximate 49.5% aggregate interest in a natural gas pipeline system located in south Louisiana.

- *Coyote Gas Treating, LLC* (“Coyote”) – 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 unconsolidated affiliates are summarized below.

	At December 31, 2004	At December 31, 2003
BALANCE SHEET DATA:		
Current assets	$ 21,652	$ 14,120
Property, plant and equipment, net	38,821	40,994
Other assets	35,149	38,865
Total assets	$ 95,622	$ 93,979
Current liabilities	$ 24,365	$ 16,782
Other liabilities	37,210	41,906
Combined equity	34,047	35,291
Total liabilities and combined equity	$ 95,622	$ 93,979

	For Year Ended December 31, 2004	2003	2002
INCOME STATEMENT DATA:			
Revenues	$257,539	$230,429	$145,289
Operating income	8,552	9,275	4,394
Net income	4,657	5,037	251

NGL Pipelines & Services segment

At December 31, 2004, our NGL Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

- *Dixie Pipeline Company* ("Dixie") – an aggregate 19.9% interest in a 1,301-mile propane pipeline and associated facilities extending from Mont Belvieu, Texas to North Carolina.

- *Venice Energy Services Company, LLC* ("VESCO") — a 13.1% interest in a natural gas processing plant, fractionation facilities, storage, and gas gathering pipelines located in southern Louisiana and, with respect to certain of the gas gathering pipelines, also in the Gulf of Mexico. 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 1).

- *Belle Rose NGL Pipeline LLC* ("Belle Rose") – a 41.7% interest in an NGL pipeline system located in south Louisiana.

- *K/D/S Promix LLC* ("Promix") – a 50% interest in an NGL fractionator and related storage and pipeline assets located in south Louisiana. In December 2004, we acquired an additional 16.7% ownership interest in Promix from Koch. As a result of this purchase, our ownership interest in Promix increased to 50%.

- *Baton Rouge Fractionators LLC* ("BRF") – an approximate 32.3% interest in an NGL fractionator located in southeastern Louisiana.

In March 2003, we purchased the remaining ownership interests in EPIK Terminalling L.P. and EPIK Gas Liquids, LLC (collectively, "EPIK"), at which time EPIK became a consolidated subsidiary of ours. In October 2003, we purchased an additional 37.4% interest in Wilprise Pipeline Company, LLC ("Wilprise"), at which time it became a 74.7% owned consolidated subsidiary of ours. In April 2004, we purchased an additional 16.7% interest in Tri-States NGL Pipeline LLC ("Tri-States"), at which time it became a 66.7% owned consolidated subsidiary of ours. See Note 4 for additional information regarding our business combinations.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's unconsolidated affiliates are summarized below.

	At December 31, 2004	At December 31, 2003
BALANCE SHEET DATA:		
Current assets	$ 101,660	$ 59,206
Property, plant and equipment, net	399,580	433,841
Other assets	16,993	4,304
Total assets	$ 518,233	$ 497,351
Current liabilities	$ 95,537	$ 54,195
Other liabilities	13,422	107,938
Combined equity	409,274	335,218
Total liabilities and combined equity	$ 518,233	$ 497,351

	For Year Ended December 31, 2004	2003	2002
INCOME STATEMENT DATA:			
Revenues	$ 298,061	$ 314,837	$ 287,236
Operating income	57,134	51,844	53,477
Net income	50,523	45,129	47,279

Petrochemical Services segment

At December 31, 2004, our Petrochemical Services segment included the following unconsolidated affiliates accounted for using the equity method:

- *Baton Rouge Propylene Concentrator, LLC* ("BRPC") – a 30% interest in a propylene fractionator located in southeastern Louisiana.
- *La Porte Pipeline Company, L.P.* and *La Porte Pipeline GP, LLC* (collectively "La Porte") – an aggregate 50% interest in a polymer grade propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas.

In November 2003, we purchased the remaining 50% of outstanding common stock of Olefins Terminal Corporation ("OTC"). As a result, OTC became a wholly owned subsidiary of ours. See Note 4 for additional information regarding our business combinations.

In September 2003, we acquired an additional 33.3% interest in *Belvieu Environmental Fuels* ("BEF"), which owns a facility that historically produced MTBE, a motor gasoline additive that enhanced octane values and is used in reformulated motor gasoline. As a result of this acquisition, BEF became a majority-owned consolidated subsidiary of ours on September 30, 2003. Previously, BEF was accounted for as an equity-method unconsolidated affiliate. In September 2004, we acquired the remaining 33.3% interest in BEF.

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 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 a non-cash asset impairment charge of $67.5 million. Our share of this loss was $22.5 million and is recorded as a component of "Equity in loss of unconsolidated affiliates" in our Statements of Consolidated Operations and Comprehensive Income for the year ended December 31, 2003.

BEF's assets were written down to fair value, which was determined by independent appraisers using present value techniques. The impaired assets principally represent the plant facility and other assets associated with MTBE production. The fair value analysis incorporates probability-weighted cash flows for future courses of action being taken (or contemplated to be taken) by BEF management, including modification of the facility to produce iso-octane and alkylate. If the underlying assumptions in the fair value analysis change resulting in the present value of expected future cash flows being less than the new carrying value of the facility, additional impairment charges may result in the future. See Note 16 for additional information regarding risks associated with our investment in BEF.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's unconsolidated affiliates are summarized below.

	At December 31,	
	2004	2003
BALANCE SHEET DATA:		
Current assets	$ 3,266	$ 4,007
Property, plant and equipment, net	57,516	61,162
Total assets	$ 60,782	$ 65,169
Current liabilities	$ 438	$ 1,224
Combined equity	60,344	63,945
Total liabilities and combined equity	$ 60,782	$ 65,169

	For Year Ended December 31,		
	2004	2003	2002
INCOME STATEMENT DATA:			
Revenues	$ 18,378	$ 14,512	$ 12,209
Operating income	5,131	2,726	2,232
Net income	5,151	2,685	2,243

Other, non-segment

The Other, non-segment category is presented for financial reporting purposes only to show the historical equity earnings we received from our 50% membership interest in the general partner of GulfTerra, *GulfTerra Energy Company, L.L.C.* ("GulfTerra GP"), which owns a 1.0% general partner interest in GulfTerra. We acquired a 50% membership interest in GulfTerra GP on December 15, 2003 in connection with Step One of the GulfTerra Merger (see Note 4). Our 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 segments. Therefore, we have segregated equity earnings from GulfTerra GP apart from our other investments to aid in comparability between the periods presented and future periods.

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8. INTANGIBLE ASSETS AND GOODWILL

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

		At December 31, 2004		At December 31, 2003	
	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value
Offshore Pipelines & Services:					
Offshore pipeline & platform customer relationships (1)	$ 205,845	$ (6,965)	$ 198,880		
Independence Hub	1,167		1,167		
Segment total	207,012	(6,965)	200,047		
Onshore Natural Gas Pipelines & Services:					
San Juan Gathering System customer relationships (1)	331,311	(6,222)	325,089		
Permian Basin customer relationships (1)	1,590	(57)	1,533		
Petal natural gas storage contracts (1)	86,726	(1,558)	85,168		
Hattiesburg natural gas storage contracts (1)	13,773	(501)	13,272		
San Juan Basin water rights (1)	750	(6)	744		
Segment total	434,150	(8,344)	425,806		
NGL Pipelines & Services:					
Shell natural gas processing agreement	206,216	(45,110)	161,106	$ (34,063)	$ 172,153
Toca-Western natural gas processing contracts	11,187	(1,444)	9,743	(885)	10,302
Toca-Western NGL fractionation contracts	20,042	(2,589)	17,453	(1,587)	18,455
Mont Belvieu Storage II contracts	8,127	(697)	7,430	(464)	7,663
Venice contracts	6,635	(601)	6,034	(136)	6,499
STMA customer relationships (1)	37,802	(1,308)	36,494		
NGL Business customer relationships (1)	32,800	(829)	31,971		
Markham NGL storage contracts (1)	32,664	(1,088)	31,576		
Morgan's Point (2)	1,652		1,652		
Segment total	357,125	(53,666)	303,459	(37,135)	215,072
Petrochemical Services:					
Mont Belvieu Splitter III contracts	53,000	(4,417)	48,583	(2,902)	50,098
BEF UOP License Fee	1,097	(109)	988	(24)	1,633
Port Neches pipeline contracts	2,400	(682)	1,718	(310)	2,090
Segment total	56,497	(5,208)	51,289	(3,236)	53,821
Total all segments	$ 1,054,784	$ (74,183)	$ 980,601	$ (40,371)	$ 268,893

(1) These intangible assets were acquired as a result of the GulfTerra Merger and the South Texas midstream assets in September 2004. These amounts are based on our preliminary purchase price allocation for the GulfTerra Merger (see Note 4), which is subject to change.

(2) These intangible assets were acquired in December 2004 in connection with our acquisition of the Morgan's Point assets. The amounts assigned to intangible assets are based upon our preliminary allocation of the acquisition purchase price, which is subject to change.

As of December 31, 2004, our primary intangible assets were as follows:

- *GulfTerra and STMA customer relationships*. These intangible assets represent the customer base that GulfTerra and the South Texas midstream assets serve through providing services, including natural gas gathering and processing, NGL fractionation and pipeline transportation. These entities conduct the majority of their business through the use of written contracts; thus, the customer relationships represent the rights we own arising from those contractual agreements. We amortize the customer relationship values using a method that closely resembles the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are consumed or otherwise used. This group of intangible assets consists of our (i) Offshore Pipelines & Platforms customer relationships; (ii) San Juan Gathering System customer relationships; (iii) Permian Basin customer relationships; (iv) STMA customer relationships and (v) NGL Business customer relationships.

- *GulfTerra storage contracts*. These intangible assets represent the contracts that GulfTerra entered into to provide for the storage of natural gas or NGLs for various customers at its Petal and Hattiesburg natural gas or Markham NGL storage facilities. These contracts are amortized on a straight-line basis over the remainder of their respective contract terms, which we estimate range from 2 to 18 years. This group of intangible assets consists of our (i) Petal natural gas storage contracts; (ii) Hattiesburg natural gas storage contracts and (iii) Markham NGL storage contracts.

- *Shell natural gas processing agreement*. We acquired this intangible asset in connection with our acquisition of certain midstream energy assets from Shell located along the Gulf Coast in 1999. The value of the Shell agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term through 2019. For additional information regarding our related party relationship with Shell, see Note 14.

- *Mont Belvieu storage and propylene fractionation contracts*. We acquired these storage and propylene fractionation contracts during 2002 in connection with our purchase of certain midstream energy assets from Diamond-Koch that were located in Mont Belvieu, Texas. The values of these contracts are being amortized on a straight-line basis over the 35-year remaining economic life of the assets to which they relate. This group of intangible assets consists of our Mont Belvieu Storage II contracts and Mont Belvieu Splitter III contracts.

- *Toca-Western contracts*. We acquired these natural gas processing and NGL fractionation contracts during 2002 in connection with our purchase of certain midstream energy assets from Toca-Western. The Toca-Western natural gas processing contracts are being amortized on a straight-line basis over the expected 20-year economic life of the natural gas supplies supporting these contracts. The value of the Toca-Western NGL fractionation contracts is being amortized on a straight-line basis over the expected 20-year remaining life of the assets to which they relate.

Our remaining intangible assets primarily represent the value of contracts rights we own under product handling and transportation agreements, processing license agreements and water rights. In general, the value of these contract rights are being amortized using the straight-line method over either the terms of underlying contracts or the remaining useful economic life of the assets to which they relate.

Goodwill. In general, goodwill represents the excess of the purchase price of an acquired entity over the amounts assigned to assets acquired (including identifiable intangible assets) and liabilities assumed. Goodwill is not amortized; however, it is subject to annual impairment testing. Our preliminary estimate of goodwill associated with the GulfTerra Merger is $376.8 million, which we allocated between our new business segments in proportion to the tangible and intangible assets we recorded for this transaction in purchase accounting. The "GulfTerra Merger" goodwill is associated with our view of the future results from GulfTerra's operations, based on the strategic location of GulfTerra's assets as well as their industry relationships. Based on miles of pipelines, GulfTerra is one of the largest natural gas gathering and transportation companies providing services to producers in the natural gas supply regions of 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. Since we have not finalized our allocation of the purchase price associated with the GulfTerra Merger, our estimate of goodwill related to this transaction is preliminary (see Note 4). The remainder of our goodwill amounts are associated with prior acquisitions, principally that of our purchase of propylene fractionation assets from Diamond-Koch in February 2002.

The following table summarizes our goodwill amounts at the dates indicated:

	At December 31, 2004	At December 31, 2003
Offshore Pipelines & Services		
GulfTerra Merger	$ 62,348	
Onshore Natural Gas Pipelines & Services		
GulfTerra Merger	290,397	
NGL Pipelines & Services		
GulfTerra Merger	24,026	
Acquisition of interest in Mont Belvieu NGL fractionator	7,857	$ 7,857
Acquisition of interest in Wilprise	880	880
Petrochemical Services		
Acquisition of Mont Belvieu propylene fractionation assets	73,690	73,690
Totals	$ 459,198	$ 82,427

The following table shows amortization expense associated with our intangible assets for the periods indicated:

	For Year Ended December 31, 2004	2003	2002
Offshore Pipelines & Services	$ 6,965		
Onshore Natural Gas Pipelines & Services	8,344		
NGL Pipelines & Services	16,531	$ 12,977	$ 12,197
Petrochemical Services	1,973	1,848	1,388
Total all segments	$ 33,813	$ 14,825	$ 13,585

For 2005, amortization expense attributable to these intangible assets is currently estimated at $86.5 million. Based on information currently available, we estimate that amortization expense related to existing intangible assets could approximate $80.2 million during 2006, $75.1 million during 2007, $70.5 million during 2008 and $65.9 million during 2009.

9. DEBT OBLIGATIONS

Our debt consisted of the following at the dates indicated:

	December 31, 2004	December 31, 2003
Operating Partnership debt obligations:		
Interim Term Loan, variable rate, repaid in May 2004 (1)		$ 225,000
364-Day Revolving Credit Facility, variable rate, terminated in September 2004 (2)		70,000
Multi-Year Revolving Credit Facility, variable rate, terminated in September 2004 (2)		115,000
364-Day Acquisition Credit Facility, variable rate, repaid in February 2005 (3, 4)	$ 242,229	
Multi-Year Revolving Credit Facility, variable rate, due September 2009 (2,4)	321,000	
Seminole Notes, 6.67% fixed-rate, $15 million due in December 2005 (5)	15,000	30,000
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	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	
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	
GulfTerra debt obligations: (5)		
Senior Notes, 6.25% fixed-rate, due June 2010 (6)	750	
Senior Subordinated Notes, 8.50% fixed-rate, due June 2010	3,858	
Senior Subordinated Notes, 8.50% fixed-rate, due June 2011	1,777	
Senior Subordinated Notes, 10.625% fixed-rate, due December 2012	84	
Total principal amount	4,288,698	2,144,000
Net unamortized discounts	(9,239)	(5,983)
Other	1,777	1,531
Subtotal long-term debt	4,281,236	2,139,548
Less current maturities of debt (7)	(15,000)	(240,000)
Long-term debt	$ 4,266,236	$ 1,899,548
Standby letters of credit outstanding (8)	$ 139,052	$ 1,300

(1) We used the proceeds from our May 2004 common unit offering to fully repay and terminate the Interim Term Loan.

(2) These facilities were terminated on September 30, 2004, and replaced by a new Multi-Year Revolving Credit Facility having $750 million of borrowing capacity due September 2009.

(3) We used the proceeds from our February 2005 common unit offering to fully repay and terminate the 364-Day Acquisition Credit Facility.

(4) These facilities became effective concurrently with the closing of the GulfTerra Merger on September 30, 2004. The new $750 million Multi-Year Revolving Credit Facility replaced the $230 million 364-Day Revolving Credit Facility and the $270 million then existing Multi-Year Revolving Credit Facility. The $750 million borrowing capacity is reduced by the amount of standby letters of credit outstanding.

(5) Solely as it relates to the assets of our GulfTerra and Seminole subsidiaries, our senior indebtedness is structurally subordinated and ranks junior in right of payment to indebtedness of GulfTerra and Seminole.

(6) Remaining notes outstanding were called and retired in February 2005.

(7) 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 Credit Facility using proceeds from an equity offering completed in February 2005. Our classification of current maturities of debt at December 31, 2003 reflected our option and ability to convert any revolving credit balance outstanding at maturity under the 364-Day Revolving Credit Facility to a one-year term loan (which would have been due October 2005) in accordance with the terms of the agreement.

(8) Of the $139 million standby letters of credit outstanding at December 31, 2004, $24 million were issued under our Multi-Year Revolving Credit Facility, and the remaining $115 million is associated with a letter of credit facility we entered into in November 2004 in connection with our Independence Hub capital project.

General description of consolidated debt

The following is a summary of the significant aspects of our debt obligations at December 31, 2004:

Parent-Subsidiary guarantor relationships. We act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Seminole Notes and the senior and 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. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own an effective 88.4% of its capital stock). The senior and senior subordinated notes of GulfTerra are unsecured obligations of GulfTerra (of which we own 100% of its limited and general partnership interests).

GulfTerra's Senior Subordinated and Senior Notes. As a result of completing the GulfTerra Merger on September 30, 2004, we recorded in consolidation GulfTerra's $921.5 million of outstanding senior and senior subordinated notes. Of this amount, $915 million was purchased on October 5, 2004 by our Operating Partnership pursuant to its tender offers. The note holders also approved amendments in connection with accepting the tender offers that removed all restrictive covenants governing the notes. For additional information regarding the tender offers, please read " – *364-Day Acquisition Credit Facility – Tender offers for GulfTerra senior and senior subordinated notes*" within this general description of debt. In February 2005, we redeemed, at a premium, the remaining $0.8 million outstanding under GulfTerra's 6.25% senior notes due June 2010.

364-Day Acquisition Credit Facility. In August 2004, our Operating Partnership entered into a new 364-day credit agreement. The $2.25 billion Acquisition Credit Facility was an unsecured 364-day facility that was used to provide interim financing for certain transactions associated with the GulfTerra Merger, the refinancing of GulfTerra's existing secured credit facility and term loans and the purchase of GulfTerra's senior and senior subordinated notes in connection with our Operating Partnership's tender offers for those notes. This facility became effective concurrent with the closing of the GulfTerra Merger and was to mature on September 29, 2005. In February 2005, we fully repaid and terminated the 364-Day Acquisition Credit Facility using proceeds we received from our February 2005 common unit offering. For additional information regarding the February 2005 common unit offering, see Note 21.

As defined by the credit agreement, variable interest rates charged under this facility generally bore 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 credit agreement provided for the mandatory prepayment of loans and termination of commitments equal to the proceeds from and upon the consummation of any public or private debt or equity offerings by us on or after August 15, 2004, excluding equity issued with respect to our distribution reinvestment plan, employee unit purchase plan and the exercise of any outstanding options with respect to our common units. With the completion of our private offering of senior notes on October 4, 2004, we repaid approximately $2 billion borrowed under this facility, which reduced our borrowing capacity under this facility by an equal amount.

This revolving credit agreement contained 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 required us to satisfy certain financial covenants at the end of each fiscal quarter. We are in compliance with these covenants at December 31, 2004.

Tender offers for GulfTerra senior and senior subordinated notes

On August 4, 2004, in anticipation of completing the GulfTerra Merger, our Operating Partnership commenced four cash tender offers to purchase any and all of the outstanding senior and senior subordinated notes of GulfTerra having a total outstanding principal amount of approximately $921.5 million. In connection with the tender offers, GulfTerra executed supplements to the indentures governing these notes that eliminated certain restrictive covenants and default provisions contained in those indentures upon our purchase of more than a majority in principal amount of each series of the outstanding senior and senior subordinated notes.

Substantially all of the GulfTerra notes ($915 million of $921.5 million) were tendered pursuant to the tender offers. On September 30, 2004, we borrowed $1.1 billion under our 364-Day Acquisition Credit Facility in anticipation of completing the tender offers and placed these funds in escrow. On October 5, 2004, our Operating Partnership purchased the notes for a total price of approximately $1.1 billion, which included $27 million related to consent payments.

The following table shows the four GulfTerra senior debt obligations affected, including the principal amount of each series of notes tendered, as well as the payment made by Enterprise to complete the tender offers.

Description	Principal Amount Tendered	Cash payments made by Enterprise		
		Accrued Interest	Tender Price (1)	Total Paid
8.50% Senior Subordinated Notes due 2010 (Represents 98.2% of principal amount outstanding)	$212,057	$ 6,209	$ 246,366	$ 252,575
10.625% Senior Subordinated Notes due 2012 (Represents 99.9% of principal amount outstanding)	133,916	4,901	167,612	172,513
8.50% Senior Subordinated Notes due 2011 (Represents 99.5% of principal amount outstanding)	319,823	9,364	359,379	368,743
6.25% Senior Notes due 2010 (Represents 99.7% of principal amount outstanding)	249,250	5,366	274,073	279,439
Totals	$915,046	$ 25,840	$1,047,430	$1,073,270

(1) Tender price includes consent payment of $30 per $1,000 principal amount tendered.

Multi-Year Revolving Credit Facility. In August 2004, our Operating Partnership entered into a five-year $750 million revolving credit agreement that includes a sublimit of $100 million for standby letters of credit. This facility became effective concurrent with the closing of the GulfTerra Merger and will mature on September 30, 2009. This facility replaced our then existing $270 million Multi-Year Revolving Credit Facility and $230 million 364-Day Revolving Credit Facility, which were terminated upon the effective date of the new facility. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to Enterprise 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 similar to those of our 364-Day Acquisition Credit Facility. We are in compliance with these covenants at December 31, 2004.

Senior Notes A, B, C and D. These fixed-rate notes are an unsecured obligation 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 GP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. These notes 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. We were in compliance with these covenants at December 31, 2004. On March 15, 2005, we repaid the $350 million in indebtedness outstanding under Senior Notes A using the proceeds we received from our February 2005 private offering of senior notes. See Note 21 for information regarding this subsequent event.

Senior Notes E, F, G and H. On September 23, 2004, our Operating Partnership priced a private offering of an aggregate of $2 billion in principal amount of senior unsecured notes in a transaction exempt from the registration requirements under the Securities Act of 1933, as amended. On October 4, 2004, these notes were issued. The interest rate, principal amount and net proceeds, before expenses, for each senior note in this offering are shown in the following table:

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Senior Note Issued	Fixed Interest Rate	Principal Amount	Bond Discount	Proceeds to Us, Before Expenses
Senior Notes E, due October 2007	4.000%	$ 500,000	$ 2,140	$ 497,860
Senior Notes F, due October 2009	4.625%	500,000	4,405	495,595
Senior Notes G, due October 2014	5.600%	650,000	4,784	645,216
Senior Notes H, due October 2034	6.650%	350,000	4,203	345,797
Totals		$ 2,000,000	$ 15,532	$ 1,984,468

The net proceeds from this offering were used to reduce debt amounts outstanding under the Operating Partnership's $2.25 billion 364-Day Acquisition Credit Facility that was used to partially fund the GulfTerra Merger on September 30, 2004.

These fixed-rate notes are unsecured obligations of our Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. The Operating Partnership's borrowings under these notes are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. These notes were issued under an indenture containing certain covenants, which restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. We are in compliance with these covenants at December 31, 2004.

On January 24, 2005, we filed a registration statement for an offer to exchange these notes for registered debt securities with identical terms. The exchange of notes was completed in March, 2005.

Senior Notes Offering. On February 15, 2005, our Operating Partnership sold $500 million in principal amount of senior notes in a private offering. See Note 21 for information regarding this subsequent event.

Pascagoula MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, our 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. We were in compliance with the covenants at December 31, 2004.

The indenture agreement for this loan contains an acceleration clause whereby if our credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's remaining at BB+ or below, 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.

Petal Industrial Development Revenue Bonds. In April 2004, Petal Gas Storage L.L.C. ("Petal"), a wholly owned subsidiary of GulfTerra, borrowed $52 million from the MBFC pursuant to a loan agreement between Petal and the MBFC. On the same date, the MBFC issued $52 million in Industrial Development Revenue Bonds to another wholly owned subsidiary of GulfTerra. The loan agreement and the Industrial Development Revenue Bonds have identical fixed interest rates of 6.25% and maturities of fifteen years. The bonds and the associated tax exemptions are authorized under the Mississippi Business Finance Act. Petal may repay the loan agreement without penalty, and thus cause the Industrial Development Revenue Bonds to be redeemed, any time after one year from their date of issue. We have netted the loan amount and the bond amount of $52 million and the interest payable and interest receivable amount of $2.2 million on our Consolidated Balance Sheet as of December 31, 2004. Beginning in the fourth quarter of 2004, we also netted the interest expense and interest income amounts of $0.8 million attributable to these instruments on our Statements of Consolidated Operations and Comprehensive Income. Our presentation of the Petal Industrial Development Revenue Bonds is reflected in accordance with the provisions of FIN No. 39, "*Offsetting of Amounts Related to Certain Contracts*", and SFAS No. 140, "*Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*", since we have the ability and intent to offset these items.

Loss due to write-off of unamortized debt issuance costs. As a result of terminating our 364-Day Revolving Credit Facility and our previous Multi-Year Revolving Credit Facility on September 30, 2004, we expensed $0.7 million of unamortized debt issuance costs.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable-rate debt obligations during 2004.

	Range of interest rates paid	Weighted-average interest rate paid
Interim Term Loan (terminated May 2004)	1.72% to 1.78%	1.76%
364-Day Revolving Credit Facility (terminated September 30, 2004)	1.72% to 4.00%	1.82%
Multi-Year Revolving Credit Facility (terminated September 30, 2004)	1.67% to 4.25%	1.83%
364-Day Acquisition Credit Facility (effective September 30, 2004)	2.67% to 4.75%	3.50%
Multi-Year Revolving Credit Facility (effective September 30, 2004)	2.64% to 5.25%	3.06%

Consolidated debt maturity table

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

Fiscal 2005	$ 15,000
” 2007	500,000
” 2009	821,000
Thereafter	2,952,698
Total scheduled principal to be repaid	$ 4,288,698

In accordance with SFAS No. 6, “*Classification of Short-Term Obligations Expected to Be Refinanced*”, the amount shown in the table above for 2005 excludes the $242.2 million principal amount due under our 364-Day Acquisition Credit Facility at December 31, 2004. We refinanced this short-term obligation using proceeds from an equity offering completed in February 2005. As a result, we have reclassified this amount to long-term debt and shown it as a component of principal amounts due after 2009.

In addition, the long-term portion of our debt obligations at December 31, 2004 reflects our refinancing of the $350 million in principal amount Senior Notes A (due March 2005) with proceeds from our issuance in March 2005 of $250 million in principal amount Senior Notes I (due March 2015) and our $250 million in principal amount Senior Notes J (due March 2035). In accordance with SFAS No. 6, the principal amount due under Senior Notes A has been reclassified to amounts due after 2009 to match the scheduled maturities of Senior Notes I and J.

Joint venture debt obligations

We have ownership interests in four joint ventures having long-term debt obligations. The following table shows (i) our ownership interest in each entity at December 31, 2004, (ii) total long-term debt obligations (including current maturities) of each unconsolidated affiliate at December 31, 2004, on a 100% basis to the joint venture and (iii) the corresponding scheduled maturities of such long-term debt.

	Our Ownership Interest	Total	Scheduled Maturities of Long-Term Debt					
			2005	2006	2007	2008	2009	After 2009
Cameron Highway (1)	50.0%	$297,000		$ 8,125	$32,500	$164,375	$16,000	$76,000
Deepwater Gateway	50.0%	144,000	$22,000	22,000	22,000	22,000	56,000	
Poseidon	36.0%	107,000				107,000		
Evangeline	49.5%	35,650	5,000	5,000	5,000	5,000	5,000	10,650
Total		$583,650	$27,000	$35,125	$59,500	$298,375	$77,000	$86,650

(1) The scheduled maturities for Cameron Highway assume that the construction loan will be converted into a term loan by July 2005 and scheduled repayments will begin on December 31, 2006.

The following is a summary of the significant aspects of the debt obligations of our unconsolidated affiliates.

Cameron Highway. In July 2003, Cameron Highway entered into a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes, to finance a substantial portion of the cost to construct the Cameron Highway oil pipeline.

The construction loan bears interest at a variable rate. Once the Cameron Highway oil pipeline has commenced operations and transported a certain level of volumes (as specified in the credit agreement), the construction loan will convert to a term loan maturing in July 2008, subject to the terms of the loan agreement. At the end of the first quarter following the first anniversary of the conversion into a term loan, Cameron Highway will be required to make quarterly principal payments of $8.1 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by January 2006, the construction loan and senior secured notes become fully due and payable. At December 31, 2004, Cameron Highway had $197 million outstanding under its construction loan at an average interest rate of 5.48%.

The interest rate on Cameron Highway's senior secured notes is 3.25% over the rate on 10-year U.S. Treasury securities. Principal payments of $4 million are due quarterly from September 2008 through December 2011, $6 million each from March 2012 through December 2012, and $5 million each from March 2013 through the principal maturity date of December 2013. At December 31, 2004, Cameron Highway had $100 million outstanding under its senior secured notes at an average interest rate of 7.36%.

The project loan facility as a whole is secured by (1) substantially all of Cameron Highway's assets, including, upon conversion to a term loan, a debt service reserve capital account, and (2) all of the equity interest in Cameron Highway. Other than the pledge of our equity interest and our construction obligations under the relevant producer agreements, the debt is non-recourse to us. The construction loan and senior secured notes prohibit Cameron Highway from making distributions to us until the construction loan is converted into a term loan and Cameron Highway meets certain financial requirements.

Deepwater Gateway. In August 2002, Deepwater Gateway, our unconsolidated affiliate which owns the Marco Polo tension-leg platform, obtained a $155 million project finance loan to finance a substantial portion of the cost to construct the Marco Polo tension-leg platform and related facilities. Construction of the Marco Polo tension- leg platform was completed during the first quarter of 2004, and in June 2004, Deepwater Gateway converted the project finance loan into a term loan which matures in June 2009. The term loan is payable in twenty equal quarterly installments of $5.5 million each (which began on September 30, 2004), and the remaining outstanding principal of $45 million is due on the maturity date. Interest rates are variable and the loan is collateralized by substantially all of Deepwater Gateway's assets. Deepwater Gateway is required to maintain a debt service reserve of not less than the projected principal, interest and fees due on the term loan for the immediately succeeding six month period. If Deepwater Gateway defaults on its payment obligations under the term loan, we would be required to pay the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of December 31, 2004, the average interest rate charged under this term loan was 4.42%.

In accordance with terms of the credit agreement, Deepwater Gateway has the right to repay the principal amount plus any accrued interest due under its term loan at any time without penalty. Deepwater Gateway has decided to extinguish its term loan. We and our 50% joint venture partner in Deepwater Gateway, Cal Dive, will make equal cash contributions to Deepwater Gateway to fund the repayment. At March 9, 2005, the term loan principal amount owed by Deepwater Gateway was $144 million.

Poseidon. Poseidon is party to a $170 million revolving credit facility which matures in January 2008. The interest rates Poseidon is charged on balances outstanding under its revolving credit facility are variable and depend on its ratio of total debt to earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon’s assets. As of December 31, 2004, the average interest rate charged under Poseidon’s revolving credit facility was 4.58%.

Evangeline. At December 31, 2004, long-term debt for Evangeline consisted of (i) $28.2 million in principal amount of 9.9% fixed-rate Series B senior secured notes that are due in 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 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 in connection with its acquisition of a contract-based intangible asset in the early 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the note until such time as the Series B note holders are either fully cash secured through debt service accounts or have been completely repaid. In general, interest accrues on the subordinated note at a variable-rate based on LIBOR plus $^{1}/_{2}$%. The variable interest rate paid on this debt at December 31, 2004 was 1.73%.

10. CAPITAL STRUCTURE

General. 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 Fourth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the “Partnership Agreement”). Our common units trade on the NYSE under the ticker symbol “EPD.” We are managed by our general partner, Enterprise GP.

On October 1, 2004, we amended and restated our Partnership Agreement by executing the Fourth Amended and Restated Agreement of Limited Partnership. The amended Partnership Agreement makes the following changes: (i) all previous amendments were consolidated into one document, (ii) certain provisions which are no longer applicable to us were deleted (such as those relating to the subordination period and classes of partnership equity securities that are no longer outstanding), and (iii) certain provisions were added to evidence our separateness from other persons and entities. A number of additional immaterial revisions were made in the amended Partnership Agreement, including updating definitions to provide consistency with the above described changes.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and Enterprise GP 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 100% to our general partner. See Note 11 for information regarding our cash distributions to partners, including incentive cash distributions to Enterprise GP.

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

Equity offerings. The Partnership Agreement generally 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 shall be established by Enterprise GP in its sole discretion without the approval of unitholders. Since October 2002, we have completed a number of common unit offerings. The following table reflects the number of common units issued and the net proceeds received from each offering:

		Net Proceeds			
Month of offering	**Number of common units issued**	**Contributed by Limited Partners**	**Contributed by General Partner**	**Contributed by General Partner in Minority Interest (1)**	**Total**
October 2002 (2)	9,800,000	$ 178,859	$ 1,807	$ 1,844	$ 182,510
January 2003 (3)	14,662,500	$ 252,942	$ 2,555	$ 2,608	$ 258,105
June 2003 (4)	11,960,000	255,891	2,584	2,639	261,114
August 2003 (5)	1,306,059	26,416	266	280	26,962
November 2003 (5)	1,577,744	32,696	334	334	33,364
Total 2003	29,506,303	$ 567,945	$ 5,739	$ 5,861	$ 579,545
February 2004 (5)	1,053,861	$ 22,684	$ 463		$ 23,147
May 2004 (6)	17,250,000	346,032	7,062		353,094
May 2004 (5)	1,757,347	34,589	706		35,295
August 2004 (7)	17,250,000	334,358	6,824		341,182
August 2004 (5)	173,033	3,151	64		3,215
November 2004 (5)	2,199,350	48,944	998		49,942
Total 2004	39,683,591	$ 789,758	$ 16,117		$ 805,875

(1) Prior to the restructuring of Enterprise GP's ownership interest in December 2003, Enterprise 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 $178.8 million of the proceeds from this offering to repay a portion of the indebtedness under our 364-Day Term Loan. The remaining proceeds were used for working capital purposes.

(3) We used $252.8 million of the proceeds from this offering to repay a portion of the indebtedness under our 364-Day Term Loan. The remaining proceeds were used for working capital purposes.

(4) We used the net proceeds from this offering to reduce indebtedness outstanding under our revolving credit facilities.

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

(6) We used the proceeds from this public offering to repay the $225 million Interim Term Loan and to temporarily reduce borrowings outstanding under our revolving credit facilities.

(7) We used $210 million of the proceeds from this public offering to reduce borrowings outstanding under our revolving credit facilities and the remainder to fund our payment obligations to El Paso under Step Two of the GulfTerra Merger.

We have on file with the SEC a $1.5 billion universal shelf registration statement covering the issuance of an unallocated amount of partnership equity or public debt obligations (separately or in combination). In February 2005, we sold 17,250,000 common units in a public offering (including the over-allotment amount of 2,250,000 common units which closed on March 11, 2005), which generated net proceeds of approximately $456.5 million (see Note 21). As a result of this offering, practically all of the available capacity under this shelf registration statement has been used. In March 2005, we filed a new $4 billion universal shelf registration statement with the SEC (see Note 21).

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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 in the purchase of additional common units. In July 2003, we filed a registration statement with the SEC covering 5,000,000 common units issuable under the DRIP. In April 2004, we filed a new registration statement with the SEC covering an additional 10,000,000 common units issuable under the DRIP. The new registration statement increased the number of common units issuable under the DRIP from 5,000,000 to 15,000,000. As a result of any reinvestment proceeds we receive, Enterprise GP is required to make cash contributions to us in order to maintain its ownership interest. Initial reinvestments under this program occurred in August 2003.

Equity interests granted on September 30, 2004 in connection with the GulfTerra Merger. Under Step Two of the GulfTerra Merger (see Note 4), Enterprise issued 1.81 of its common units for each GulfTerra common unit (including restricted common units) remaining after Enterprise's purchase of 2,876,620 GulfTerra common units owned by El Paso. The 104,549,823 Enterprise common units (including restricted common units) issued in the conversion were calculated as shown in the following table:

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:	
Enterprise's purchase of GulfTerra Series C units from El Paso in connection with Step Two	(10,937,500)
Enterprise's 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 by Enterprise	57,762,369
Conversion ratio (1.81 Enterprise common units for each GulfTerra common unit)	1.81
Enterprise 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 Enterprise common units immediately prior to and after proposed GulfTerra Merger was announced on December 15, 2003 (see following table)	$ 23.39
Fair value of Enterprise common units issued in conversion of remaining GulfTerra common units	$ 2,445,420

In accordance with purchase accounting, the $2.4 billion value of Enterprise's common units issued in Step Two of the GulfTerra Merger is based on the average closing price of Enterprise's common units immediately prior to and after the proposed merger was announced on December 15, 2003:

December 11, 2003	$ 23.10
December 12, 2003	22.80
December 16, 2003	23.85
December 17, 2003	23.80
Average closing price per unit of Enterprise common units immediately prior to and after the proposed merger was announced on December 15, 2003	$ 23.39

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 shows the detail for this consideration:

Fair value of Enterprise common units issued in conversion of remaining GulfTerra common units	$ 2,445,420
Fair value of equity interests issued to acquire remaining 50% membership interest in GulfTerra GP (voting interest)(1)	461,347
Fair value of other Enterprise equity interests issued for unit awards and Series F2 convertible units(2)	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 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 GP granted to El Paso in this transaction from the 50% membership interest in GulfTerra GP that Enterprise 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 Enterprise to purchase its initial 50% non-voting membership interest in GulfTerra GP in December 2003. The contribution of this 50% membership interest to Enterprise is allocated for financial reporting purposes to Enterprise's 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) See discussion of "*Series F2 convertible units assumed in connection with the GulfTerra Merger*" and "*Restricted common units issued during 2004*" included within this Note 10 for additional information.

Series F2 convertible units assumed in connection with the GulfTerra Merger. In May 2003, GulfTerra issued 80 Series F convertible units in a registered offering to an institutional investor. Each Series F convertible unit was comprised of two separate detachable units – a Series F1 convertible unit and a Series F2 convertible unit – that had identical terms except for vesting and termination dates and the number of common units into which they could be converted. Prior to the GulfTerra Merger, all the Series F1 convertible units were converted to GulfTerra common units by the holder. As a result of the GulfTerra Merger, we assumed GulfTerra's obligation associated with the 80 Series F2 convertible units. All Series F2 convertible units outstanding at the merger date were converted into rights to receive Enterprise common units. The number of Enterprise common units and the price per unit at conversion were adjusted based on the 1.81 exchange ratio. The Series F2 units were convertible into up to $40 million of Enterprise common units.

On October 29, 2004, 60 of the 80 outstanding Series F2 convertible units were converted into 1,458,434 Enterprise common units. As a result of this conversion, we received a payment of $30 million from the holder of the Series F2 convertible units (representing a conversion price of $20.57 per Enterprise common unit).

On November 8, 2004, the remaining 20 outstanding Series F2 convertible units were converted into 491,883 Enterprise common units. As a result of this conversion, we received a payment of $10 million from the holder of the Series F2 convertible units (representing a conversion price of $20.33 per Enterprise common unit).

The following table reflects the number of common units issued and the net proceeds received from the conversions of Series F2 convertible units into common units during 2004:

Month of Conversion	Number of common units issued	Net Proceeds: Contributed by Limited Partners	Net Proceeds: Contributed by General Partner	Total
October 2004	1,458,434	$ 29,100	$ 594	$ 29,694
November 2004	491,883	9,700	198	9,898
Total 2004	1,950,317	$ 38,800	$ 792	$ 39,592

Restricted common units. We began issuing restricted common units to key employees of EPCO in May 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, is 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. Unearned compensation, representing the fair market value of these units at the date of issuance, is 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. Lastly, performance-based restricted units are counted as outstanding units for dilutive earnings per unit purposes only.

During 2004, EPCO issued 434,225 time-vested restricted units to key management personnel of EPCO (who work on our behalf) as a means of retaining and compensating them for long-term performance and to increase their ownership in Enterprise. In addition, we issued 54,300 performance-based restricted common units to certain management personnel who joined us as a result of the GulfTerra Merger.

Total unamortized deferred compensation attributable to both classes of restricted units at December 31, 2004 was $10.9 million. We recorded $0.8 million of compensation expense for year ended December 31, 2004, which is reflected as a component of selling, general and administrative expenses. Deferred compensation is reflected as a reduction of partners' equity and allocated to our partners in accordance with their respective ownership interests.

Restructuring of general partner ownership interests in December 2003. In December 2003, we restructured Enterprise GP's ownership interest in us and our Operating Partnership from a 1% ownership in us and a 1.0101% ownership in the Operating Partnership to a 2% ownership in us. As a result, our effective ownership in the Operating Partnership increased to 100% from 98.9899%. The purpose of the restructuring was to simplify and reduce the cost of compliance with the SEC rules relating to financial reporting requirements of subsidiaries. As a result of the restructuring, the Operating Partnership became exempt from the reporting requirements of Section 15(d) of the Securities Exchange Act of 1934 pursuant to Rule 12h-5 thereunder.

Two-for-one unit split in February 2002. In February 2002, Enterprise GP approved a two-for-one split of each class of our partnership units. The unit split was accomplished by distributing one additional partnership unit for each partnership unit outstanding to holders of record on April 20, 2002. The units were distributed on May 15, 2002.

Conversion of Class B special units to common units. In December 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO, for $100 million in a private transaction. Enterprise GP contributed approximately $2 million in order to maintain its ownership interest. The purchase price for the Class B special units was $22.6575 per unit, representing a 5% discount from the $23.85 closing price of our common units on the NYSE on December 16, 2003. The 5% discount was consistent with the 5% discount available to all our unitholders under our distribution reinvestment plan.

On July 29, 2004, we requested that our common unitholders approve the conversion of all of the Class B special units into common units on a one-for-one basis at a special meeting that was held on July 29, 2004, to approve our merger with GulfTerra. On this date, our common unitholders approved the conversion and our 4,413,549 Class B special units converted to an equal number of common units. This conversion resulted in a reclassification of the $99 million capital account balance for the Class B special units to common units.

Prior to their conversion, the Class B special units had rights identical to our common units with respect to distributions and other matters. However, the Class B special units did not have voting rights and were not deemed to be outstanding for purposes of determining whether a quorum is present or whether the approval of the requisite number of holders of our units had been obtained.

Conversion of subordinated units to common units. During 2003, the remaining 32,114,804 subordinated units owned by EPCO converted to common units as a result of our satisfying certain financial tests. The subordinated units had no voting rights until their conversion to common units; however, they did receive allocations of income and loss. These conversions had no impact on our earnings per unit calculations or cash distributions since subordinated units were already included in both the basic and fully diluted earnings per unit calculations and were distribution bearing.

Conversion of Class A special units to common units. Class A special units were issued to Shell in conjunction with our acquisition of certain of Shell's U.S. Gulf Coast midstream energy assets in 1999 and a related contingent unit agreement. We issued 29,000,000 Class A special units in August 1999 in connection with the acquisition. Subsequently, Shell met certain performance criteria in 2000 and 2001 that obligated us to issue an additional 12,000,000 Class A special units to Shell (6,000,000 in August 2000 and 6,000,000 in August 2001) under a contingent unit agreement. Of the cumulative 41,000,000 Class A special units issued, 2,000,000 converted to common units in August 2000, 10,000,000 converted in August 2001, 19,000,000 converted in August 2002 and 10,000,000 converted in August 2003. These conversions had a dilutive impact on basic earnings per unit since they increase 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. Under NYSE rules, the conversion of the Class A special units to common units required the approval of a majority of common unitholders. An affiliate of EPCO (which owns a majority of outstanding common units) voted in favor of such conversion, which provided the necessary votes for approval.

Treasury units. During 1999, our Operating Partnership established its wholly owned EPOLP 1999 Grantor Trust (the "1999 Trust") to fund potential future obligations under the EPCO Agreement with respect to EPCO's long-term incentive plan (through the exercise of options granted to EPCO employees or directors of Enterprise GP). Beginning in 2000, we and the 1999 Trust were authorized by Enterprise GP to repurchase up to 2,000,000 publicly-held common units under a buy-back program. The repurchases will be made during periods of temporary market weakness at price levels that would be accretive to our remaining unitholders. Under the terms of the original buy-back program, common units repurchased by us were retired and common units repurchased by the 1999 Trust were classified as treasury units. In 2002, the buy-back program was modified to classify common units repurchased by us as treasury units. After deducting for those common units repurchased in prior periods, we and the 1999 Trust could repurchase under the buy-back program up to 618,400 publicly traded common units at December 31, 2004.

The common units repurchased by us or the 1999 Trust 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 (see Note 13), treasury units are not considered to be outstanding.

During 2002, 532,000 common units were repurchased at a cost of $12.8 million and placed in treasury. During 2003, we reissued 30,887 treasury units at a cost of $0.6 million primarily due to our obligations under EPCO employee unit option agreements and recorded a small gain on the transactions. We also retired 30,000 treasury units during 2003 at a cost of $0.6 million to us. During 2004, we reissued 371,113 treasury units at a cost of $7.9 million primarily due to our obligations under EPCO employee unit option agreements and recorded a small gain on the transactions.

Changes in Limited Partners' Equity. The following table details the changes in limited partners' equity since January 1, 2002:

	Common units	Restricted Common units	Subord. units	Class A Special units	Class B Special units	Total
Balance, January 1, 2002	$ 651,872		$ 193,107	$ 296,634		$ 1,141,613
Net income	69,636		15,201			84,837
Operating leases paid by EPCO	6,872		2,071			8,943
Cash distributions to partners	(153,449)		(49,564)			(203,013)
Conversion of 19 million Class A special units to common units	152,708			(152,708)		—
Conversion of 10.7 million subordinated units to common units	44,265		(44,265)			—
Proceeds from issuance of common units	178,859					178,859
Treasury units reisssued to satisfy unit options	(928)		(262)			(1,190)
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	(256,832)		(30,482)			(287,314)
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)			—
Proceeds from issuance of common units	567,945					567,945
Proceeds from issuance of Class B special units					100,000	100,000
Restructuring of Enterprise 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	(394,741)	(218)			(3,288)	(398,247)
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

Unit History table. 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	Subord. Units	Class A Special Units	Class B Special Units	Treasury Units
Balance, January 1, 2002	102,721,830		42,819,740	29,000,000		327,200
Conversion of Class A special units to common units in August 2002	19,000,000			(19,000,000)		
Conversion of subordinated units to common units in August 2002	10,704,936		(10,704,936)			
Common units issued in October 2002	9,800,000					
Treasury unit purchases	(532,000)					532,000
Balance, December 31, 2002	141,694,766		32,114,804	10,000,000		859,200
Common units issued in January 2003	14,662,500					
Conversion of subordinated units to common units in May 2003	10,704,936		(10,704,936)			
Common units issued in June 2003	11,960,000					
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)			
Common units issued in August 2003	1,306,059					
Common units issued in November 2003	1,578,389					
Common units issued in December 2003	20,000					
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 February 2004	1,053,861					
Common units issued in connection with May 2004 offering	17,250,000					
Other common units issued in May 2004	1,757,347					
Restricted common units issued in May 2004		81,500				
Conversion of Class B special units to common units in July 2004	4,413,549				(4,413,549)	
Common units issued in connection with August 2004 offering	17,250,000					
Other common units issued in August 2004	173,033					
Common and restricted common units issued to GulfTerra unitholders on September 30, 2004 in connection with the GulfTerra Merger	104,495,523	54,300				
Other restricted common units issued in September 2004		32,500				
Common units issued in connection with conversion of Series F2 units in October 2004	1,458,434					
Restricted common units issued in October 2004		307,460				
Common units issued in connection with conversion of Series F2 units in November 2004	491,883					
Other common and restricted common units issued in November 2004	2,215,837	12,765				
Treasury units reissued to satisfy unit options	371,113					(371,113)
Balance, December 31, 2004	364,297,340	488,525	—	—	—	427,200

11. DISTRIBUTIONS

We expect, to the extent there is sufficient available cash from Operating Surplus (as defined by the 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 GP's percentage interest in our quarterly cash distributions is increased after certain specified target levels of distribution rates are met. In December 2002, we amended our Partnership Agreement to eliminate the Enterprise GP's right to receive 50% of our quarterly cash distributions with respect to that portion of the distribution based on declared rates that exceed $0.392 per common unit. Furthermore, Enterprise GP has capped its incentive distribution rights at 25% of our quarterly cash distributions with respect to that portion of the distribution based on declared rates that exceed $0.3085 per common unit. No consideration was paid to Enterprise GP to give up this right. As amended, Enterprise GP's quarterly incentive distribution thresholds are as follows (which include adjustments for the December 2003 restructuring of the Enterprise GP's ownership interest in us and our Operating Partnership):

- 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 made incentive distributions to Enterprise GP of $32.4 million, $19.7 million and $9.8 million during the years ended December 31, 2004, 2003 and 2002, respectively.

The following table summarizes quarterly cash distribution rates per unit during the periods indicated and the related record and distribution payment dates.

	Cash Distribution History		
	Distribution per Unit (1)	Record Date	Payment Date
2002			
1st Quarter	$ 0.3350	Apr. 30, 2002	May 10, 2002
2nd Quarter	$ 0.3350	Jul. 31, 2002	Aug. 12, 2002
3rd Quarter	$ 0.3450	Oct. 31, 2002	Nov. 12, 2002
4th Quarter	$ 0.3450	Jan. 31, 2003	Feb. 12, 2003
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. 11, 2004
3rd Quarter	$ 0.3950	Oct. 29, 2004	Nov. 5, 2004
4th Quarter	$ 0.4000	Jan. 31, 2005	Feb. 14, 2005

(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 amounts shown in the table correspond to the cash flows for the quarters indicated. The actual cash distributions occur within 45 days after the end of such quarter.

12. PROVISION FOR INCOME TAXES FOR CERTAIN PIPELINE OPERATIONS

Our provision for income taxes is limited to certain income-based state franchise tax obligations of our Mid-America and Seminole pipelines and federal tax obligations of our Seminole pipeline (both pipeline systems were acquired in 2002). One of our subsidiaries, which owns the Seminole pipeline, is a corporation and substantially our only consolidated entity subject to federal income taxes. The following table summarizes our provision for income taxes for the periods indicated:

	For Year Ended December 31,		
	2004	2003	2002
Current:			
Federal tax benefit			$ (391)
State tax expense (benefit)	$ 157	$ 47	(55)
Total current	157	47	(446)
Deferred:			
Federal	1,620	4,556	1,812
State	1,984	690	268
Total deferred	3,604	5,246	2,080
Provision for income taxes	$ 3,761	$ 5,293	$ 1,634

Net deferred tax assets primarily relate to federal tax net operating loss carryovers and differences in the book and tax basis of property, plant and equipment. The federal tax net operating loss carryovers are projected to be utilized within the 20 year carryover period. A valuation allowance of $0.1 million was recorded in 2004 against the benefit of both the current year and all prior year state tax net operating losses. The state net operating loss carryovers are not expected to be utilized within the 5 year carryover period and will expire over the next 3 to 5 years.

13. 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 (i.e., common and restricted common units) outstanding during a period. 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 July 2004.

In general, diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of:

- the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit);
- the weighted-average number of performance-based restricted common units outstanding during a period; and
- the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the “incremental option units”).

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. Treasury units are not considered to be outstanding units; therefore, they are excluded from the computation of both basic and diluted earnings per unit.

In a period of net operating losses, the performance-based restricted units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. See Note 10 for information regarding our performance-based restricted units issued in September 2004. 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 beginning 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.

Beginning in August 2003, we started reissuing treasury units to satisfy our obligations under EPCO unit option agreements. The reissuance of these treasury units to satisfy EPCO's unit option liability has a dilutive effect on our earnings per unit. Prior to August 2003, EPCO had purchased practically all of the common units associated with its 1998 Plan in the open market. As a result, EPCO's unit option plan did not have any effect on our fully diluted earnings per unit in prior periods.

The amount of net income allocated to limited partner interests is derived by subtracting our general partner's share of our net income from net income. The following table shows the allocation of net income to our general partner for the periods indicated:

	For The Year Ended December 31,		
	2004	2003	2002
Net income	$ 268,261	$ 104,546	$ 95,500
Less incentive earnings allocations to Enterprise GP	(32,391)	(19,699)	(9,806)
Net income available after incentive earnings allocation	235,870	84,847	85,694
Multiplied by Enterprise GP ownership interest (1)	2.0%	1.2%	1.0%
Standard earnings allocation to Enterprise GP	$ 4,717	$ 1,030	$ 857
Incentive earnings allocation to Enterprise GP	$ 32,391	$ 19,699	$ 9,806
Standard earnings allocation to Enterprise GP	4,717	1,030	857
Enterprise GP interest in net income	$ 37,108	$ 20,729	$ 10,663

(1) Enterprise 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 (see Note 10). The 1.2% ownership interest shown for 2003 reflects the weighted-average of the Enterprise GP's ownership interest during the year.

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The following tables show our calculation of limited partners' interest in net income, basic earnings per unit and diluted earnings per unit for the periods indicated:

	For The Year Ended December 31, 2004	2003	2002
Income before changes in accounting principles and Enterprise GP interest	$ 257,480	$ 104,546	$ 95,500
Cumulative effect of changes in accounting principles	10,781		
Net income	268,261	104,546	95,500
Enterprise GP interest in net income	(37,108)	(20,729)	(10,663)
Net income available to limited partners	$ 231,153	$ 83,817	$ 84,837
BASIC EARNINGS PER UNIT			
Numerator			
Income before changes in accounting principles and Enterprise GP interest	$ 257,480	$ 104,546	$ 95,500
Cumulative effect of changes in accounting principles	10,781		
Enterprise GP interest in net income	(37,108)	(20,729)	(10,663)
Limited partners' interest in net income	$ 231,153	$ 83,817	$ 84,837
Denominator			
Common units	262,838	183,779	119,820
Restricted common units	141		
Subordinated units		15,955	35,634
Class B special units	2,532	181	
Total	265,511	199,915	155,454
Basic earnings per unit			
Income before changes in accounting principles and Enterprise GP interest	$ 0.97	$ 0.52	$ 0.62
Cumulative effect of changes in accounting principles	0.04		
Enterprise GP interest in net income	(0.14)	(0.10)	(0.07)
Limited partners' interest in net income	$ 0.87	$ 0.42	$ 0.55
DILUTED EARNINGS PER UNIT			
Numerator			
Income before changes in accounting principles and Enterprise GP interest	$ 257,480	$ 104,546	$ 95,500
Cumulative effect of changes in accounting principles	10,781		
Enterprise GP interest in net income	(37,108)	(20,729)	(10,663)
Limited partners' interest in net income	$ 231,153	$ 83,817	$ 84,837
Denominator			
Common units	262,838	183,779	119,820
Restricted common units	141		
Subordinated units		15,955	35,634
Class A special units		5,808	21,036
Class B special units	2,532	181	
Performance-based restricted units	14		
Series F2 convertible units	22		
Incremental option units	498	644	
Total	266,045	206,367	176,490
Diluted earnings per unit			
Income before changes in accounting principles and Enterprise GP interest	$ 0.97	$ 0.51	$ 0.54
Cumulative effect of changes in accounting principles	0.04	—	—
Enterprise GP interest in net income	(0.14)	(0.10)	(0.06)
Limited partners' interest in net income	$ 0.87	$ 0.41	$ 0.48

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14. RELATED PARTY TRANSACTIONS

The following table summarizes our related party transactions for the periods indicated:

	For Year Ended December 31, 2004	2003	2002
Revenues from consolidated operations			
EPCO and subsidiaries	$ 2,697	$ 4,241	$ 3,630
Shell	542,912	293,109	282,820
Unconsolidated affiliates	258,541	266,894	196,267
Total	$ 804,150	$ 564,244	$ 482,717
Operating costs and expenses			
EPCO and subsidiaries	$ 202,561	$ 149,626	$ 103,210
Shell	725,420	607,277	531,712
Unconsolidated affiliates	37,587	43,752	60,657
Total	$ 965,568	$ 800,655	$ 695,579
Selling, general and administrative expenses			
EPCO Administrative Services Agreement	$ 27,454	$ 27,518	$ 24,204
Other EPCO transactions	653	442	n/a
Total	$ 28,107	$ 27,960	$ 24,204

Relationship with EPCO

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise GP, our general partner. In addition, the executive and other officers of Enterprise GP are employees of EPCO, including Robert G. Phillips who is Chief Executive Officer and a director of Enterprise GP. The principal business activity of Enterprise GP is to act as our managing partner.

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. In addition, at December 31, 2004, EPCO and Dan Duncan LLC, together, owned 90.1% of the membership interests of Enterprise GP, which in turn owns a 2% general partner interest in us. In January 2005, an affiliate of EPCO, Enterprise GP Holdings L.P., acquired El Paso's 9.9% membership interest in Enterprise GP (see Note 21). As a result of this transaction, EPCO and its affiliates own 100% of Enterprise GP.

In addition, trust affiliates of EPCO, the beneficiaries of which are the shareholders of EPCO (the 1998 Trust and 2000 Trust), owned 11,387,615 of our common units at March 15, 2005. Collectively, Mr. Duncan, through his beneficial ownership of our common units held personally, by the 1998 and 2000 Trusts and through subsidiaries of EPCO, controlled 37.4% of our common units at March 15, 2005.

Our agreements with EPCO are not the result of arm's-length transactions, and there can be no assurance that any of the transactions provided for therein are effected on terms at least as favorable to the parties to such agreement as could have been obtained from unaffiliated third parties.

Administrative Services Agreement. As stated previously, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative Services Agreement. Under the current terms of the Administrative Services Agreement, EPCO agrees to:

- employ the personnel necessary to manage our business and affairs (through Enterprise GP);
- employ the operating personnel involved in our business;
- allow us to participate as named insureds in EPCO's current insurance program with the costs being allocated among the parties on the basis set forth in the agreement;

- sublease to us certain equipment which it holds pursuant to operating leases for one dollar per year and to assign to us its purchase option under such leases (the "retained leases"). EPCO remains liable for the cash lease payments associated with these assets.

Operating costs and expenses (as shown on our Statements of Consolidated Operations and Comprehensive Income) treat the retained lease-related payments made by EPCO on our behalf as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded as a general contribution to the partnership. As of December 31, 2004, the remaining retained leases were for a cogeneration unit and approximately 100 railcars. During 2004, we exercised our options to purchase an isomerization unit and related equipment at a cost of $17.8 million. Should we decide to exercise the purchase options associated with the remaining retained leases (which are also at fair value), an additional $2.3 million would be payable in 2008 and $3.1 million in 2016. In addition to retained lease expense, operating costs and expenses include compensation charges for EPCO's employees who operate our facilities.

Selling, general and administrative costs (as shown in our Statements of Consolidated Operations and Comprehensive Income) include the costs we pay EPCO for administrative support. Prior to January 1, 2004, our payments to EPCO and related non-cash expenses for administrative support were based on the following:

- We reimbursed EPCO for our share of the costs of certain of its employees in administrative positions that were active at the time of our initial public offering in July 1998 (the "pre-expansion" administrative personnel). This includes costs associated with equity-based awards granted to certain individuals within this group. Our obligation for reimbursing these costs was covered by the EPCO Administrative Service Fee. We paid $17.9 million and $16.6 million of such fees to EPCO during 2003 and 2002, respectively.

- To the extent that EPCO's actual cost of providing the pre-expansion administrative personnel exceeded the Administrative Service Fee charged us during a given year, we recorded a non-cash expense equal to the difference as a non-cash selling, general and administrative cost. The offset was recorded in Partners' Equity on the Consolidated Balance Sheets as a general contribution to the partnership. The actual amounts incurred by EPCO for providing these services did not materially exceed the capped amount for the year ended December 31, 2002. For the year ended December 31, 2003, we recorded $0.4 million in non-cash expense related to this excess.

- We also reimburse EPCO for all costs it incurs related to administrative personnel it hires in response to our expansion and new business activities. This includes costs attributable to equity-based awards granted to members of this group.

Effective January 1, 2004, the Administrative Services Agreement was amended to eliminate the fixed Administrative Services Fee and to provide that we reimburse EPCO for all costs related to administrative support regardless of whether the costs are related to pre-expansion or expansion personnel who work on our behalf.

On October 22, 2004, the Administrative Services Agreement was amended further to evidence our separateness from other persons and entities, to reflect a five-year license we granted for EPCO's use of service marks owned by us and to provide for reimbursement of EPCO's costs of discontinuing the use of those service marks over the term of the license. This amendment also provides that if EPCO and its affiliates are offered by a third party, or discover an opportunity to acquire from a third party, a business or assets that is or are in the same or similar line of business then being conducted by the Operating Partnership or in a line of business that would be a natural extension of any business then being conducted by the Operating Partnership (a "Business Opportunity"), EPCO shall promptly advise the Board of Directors of Enterprise GP of such Business Opportunity and offer such Business Opportunity to the Operating Partnership. If the Board of Directors of Enterprise GP does not advise EPCO within 10 days following the receipt of such notice that we wish to pursue such Business Opportunity, EPCO shall then be permitted to pursue such Business Opportunity. If the Board of Directors of Enterprise GP advises EPCO within such 10 day period that we want to pursue such Business Opportunity, EPCO shall not be permitted to pursue such Business Opportunity unless the Board of Directors of Enterprise GP subsequently advises EPCO that it has abandoned its pursuit of such Business Opportunity.

Other related party transactions with EPCO. The following is a summary of other significant related party transactions between EPCO and us, including those between EPCO and our unconsolidated affiliates.

- Prior to January 1, 2004, EPCO was the operator of our MTBE facility and Houston Ship Channel NGL import facility. During 2003 and 2002, we paid EPCO $0.8 million for such services. Such payments were terminated effective January 1, 2004.

- We have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLs and other products.

- In the normal course of business, we also buy from and sell to EPCO's Canadian affiliate certain NGL products.

We and Enterprise GP are separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from EPCO and its other affiliates. EPCO primarily depends on the cash distributions it receives as an equity owner in us to fund its other operations and to meet its debt obligations. For the years ended December 31, 2004, 2003 and 2002, EPCO received $173.7 million, $160.4 million and $146.6 million in quarterly cash distributions from us, respectively.

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At March 15, 2005, Shell owned approximately 9.5% of our common units. In March 2005, we registered for resale Shell's 36,572,122 common units under a registration rights agreement we executed with Shell in connection with our acquisition of certain of Shell's Gulf Coast midstream energy businesses in September 1999. For additional information regarding this subsequent event, see Note 21. Shell sold its 30.0% interest in Enterprise GP to a subsidiary of EPCO in September 2003.

Shell is one of our largest customers. For the years ended December 31, 2004, 2003 and 2002, Shell accounted for 6.5%, 5.5% and 7.9%, 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.

The most significant contract affecting our natural gas processing business is the Shell margin-band/keepwhole processing agreement, which grants us the right to process Shell'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.

We have also completed a number of business acquisitions and asset purchases involving Shell since 1999, including the acquisition of midstream energy assets located along the Gulf Coast for approximately $528.8 million in 1999; the purchase of the Lou-Tex Propylene pipeline for $100 million in 2000; and the acquisition of the Acadian Gas pipeline system in 2001 for $243.7 million.

Relationships with unconsolidated affiliates

Our investment in unconsolidated affiliates with industry partners is a vital component of our business strategy. These investments are a means by which we conduct our operations to align our interests with a supplier of raw materials or a consumer 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. The following summarizes significant related party transactions we have 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. For the years ended December 31, 2004, 2003 and 2002, revenues from Evangeline were $233.9 million, $212.7 million and $131.6 million, respectively. In addition, we have also furnished $11.1 million in letters of credit on behalf of Evangeline.

- We pay transportation fees to Dixie for propane movements on their system initiated by our NGL marketing activities. For the years ended December 31, 2004, 2003 and 2002, we paid Dixie $13.1 million, $11.3 million and $12.2 million, respectively, in such transportation fees.

- We pay Promix for the transportation, storage and fractionation of certain of our mixed NGL volumes. In addition, we sell natural gas to Promix for their fuel requirements. For the years ended December 31, 2004, 2003 and 2002, we paid Promix $23.2 million, $17.5 million and $18.4 million, respectively, for their services. Additionally, for the years ended December 31, 2004, 2003 and 2002, revenues from Promix for the purchase of natural gas were $18.6 million, $19.6 million and $12.7 million, respectively.

Prior to its becoming a consolidated subsidiary in March 2003, we paid EPIK for export services to load product cargoes for our NGL and petrochemical marketing customers. Also, prior to its becoming a consolidated subsidiary in September 2003, we sold high purity isobutane to BEF as a feedstock and purchased certain of BEF's by-products. We also received transportation fees for BEF's shipments of MTBE on our HSC pipeline and fractionation revenues for reprocessing mixed feedstock streams generated by BEF.

We enter into management agreements with some of our unconsolidated affiliates under which our unconsolidated affiliates pay us management fees for the operation and management of their assets. For the years ended December 31, 2004, 2003 and 2002, such fees approximated $2.1 million, $1.5 million and $1.4 million, respectively. Additionally, on occasion we pay for construction costs on behalf of our unconsolidated affiliates during the initial construction phase of their assets, and these amounts are settled by direct reimbursements for the amounts we are owed from our unconsolidated affiliates.

15. UNIT OPTION PLAN ACCOUNTING

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 purchases common units to fund its obligations under the 1998 Plan at fair value either in the open market or from us (in the form of newly issued common units or reissued treasury units).

We account for our share of the costs of these awards using the intrinsic value-based method in accordance with APB No. 25, "*Accounting for Stock Issued to Employees*." The exercise price of each option granted is equivalent to or greater than the market price of the unit 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. The option-related reimbursements (as described below) that we make to reimburse EPCO for its costs related to these awards are a component of "Cash distributions to partners" as shown in our Statements of Consolidated Partners' Equity.

When employees exercise unit options, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units awarded to the employee. Effective January 1, 2004, with the amendment of our Administrative Services Agreement, we became responsible for reimbursing EPCO for all the costs it incurs when unit options are exercised. Under the amended agreement, our payment to EPCO is in the form of an option-related reimbursement regardless of how the option liability is satisfied (i.e., through open market purchases or units acquired from EPCO affiliates or us). During 2004 and 2003, we made $3.8 million and $2.7 million, respectively, in option-related reimbursements to EPCO to meet our obligations under EPCO's 1998 Plan.

Prior to January 1, 2004, our responsibility for reimbursing EPCO for the cash outlay it incurred when these options were exercised was as follows:

- We reimbursed EPCO for the costs attributable to unit option awards granted to operations personnel it employed on our behalf.
- We reimbursed EPCO for the costs attributable to unit option awards granted to administrative and management personnel it hired in response to our expansion and business activities.
- We paid EPCO for our share of the costs attributable to unit option awards granted to certain of its employees in administrative and management positions that were active at the time of our initial public offering in July 1998 under one of two methods described as follows:
  - if EPCO purchased common units in open market to fund its obligation to any employee of this group, the cost was reimbursed by us through the Administrative Service Fees we paid EPCO. EPCO was responsible for the actual cost of such award when the option was exercised. To the extent that EPCO's total administrative expense incurred on our behalf (including the expense associated with equity-based awards satisfied through open market purchases) exceeded the annual Administrative Service Fee we paid to EPCO, such excess costs resulted in a non-cash charge to our earnings as a related-party expense and a corresponding increase in Partners' Equity recorded as a general contribution; or
  - if EPCO requested us to provide units to satisfy its obligations to these employees, we reimbursed EPCO for its actual costs of such awards.

On July 1, 2005, we will adopt the provisions of *SFAS No. 123(R), "Share-Based Payment."* This accounting guidance, which is applicable for the first interim or annual reporting period beginning after June 15, 2005, replaces SFAS No. 123, "*Accounting for Stock-Based Compensation*" and supersedes APB No. 25, "*Accounting for Stock Issued to Employees*." For additional information regarding this recent accounting standard, see Note 2.

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 January 1, 2002	2,201,640	$ 11.88
Granted	379,000	23.42
Exercised	(270,562)	4.98
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
Options exercisable at:		
December 31, 2002	711,078	$ 7.83
December 31, 2003	509,000	$ 9.68
December 31, 2004	1,154,000	$ 14.65

The following table provides additional information regarding our unit options outstanding at December 31, 2004:

Range of Strike Prices	Options outstanding at December 31, 2004	Weighted Average Remaining Contractual Life (in Years)	Weighted Average Strike Price	Options Exercisable at December 31, 2004 Number Exercisable at December 31, 2004	Options Exercisable at December 31, 2004 Weighted Average Strike Price
$ 7.75 - - $ 9.00	224,000	4.75	$ 8.44	224,000	$ 8.44
$11.63 - $12.56	110,000	5.91	12.00	110,000	12.00
$15.93 - $17.63	755,000	6.11	16.16	750,000	16.15
$20.00 - $24.73	1,374,000	8.82	22.55	70,000	22.64
	2,463,000			1,154,000	

The weighted-average fair value of options granted during 2004, 2003 and 2002 was $2.26, $2.17 and $3.12 per option, respectively.

16. COMMITMENTS AND CONTINGENCIES

Redelivery Commitments

We store and transport 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, 2004, NGL and petrochemical volumes aggregating 13.5 million barrels were due to be redelivered to their owners along with 18,038 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 14). This includes the costs associated with equity-based awards granted to these employees. At December 31, 2004, there were 2,463,000 options outstanding to purchase common units under EPCO's 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 $18.84 per common unit. At December 31, 2004, 1,154,000 of these unit options were exercisable. An additional 374,000, 25,000 and 910,000 of these unit options will be exercisable in 2005, 2006 and 2008, 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 15 for additional information regarding our accounting for unit options.

Other commitments

The following table summarizes our various contractual obligations at December 31, 2004. A description of each type of contractual obligation follows.

	Payment or Settlement due by Period						
Contractual Obligations	Total	2005	2006	2007	2008	2009	Thereafter
Scheduled maturities of long-term debt	$4,288,698	$ 15,000		$500,000		$821,000	$2,952,698
Operating lease obligations	$ 88,899	$ 15,012	$ 13,328	$ 12,294	$ 9,496	$ 5,418	$ 33,351
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$1,160,829	$ 165,120	$142,133	$142,133	$142,522	$142,133	$ 426,788
NGLs	$ 174,281	$ 42,664	$ 10,968	$ 10,968	$ 10,968	$ 10,968	$ 87,745
Petrochemicals	$1,791,983	$1,010,907	$667,288	$107,540	$ 6,248		
Other	$ 166,706	$ 41,706	$ 32,179	$ 30,092	$ 28,690	$ 18,155	$ 15,884
Underlying major volume commitments:							
Natural gas (in BBtus)	149,705	21,855	18,250	18,250	18,300	18,250	54,800
NGLs (in MBbls)	5,657	1,267	366	366	366	366	2,926
Petrochemicals (in MBbls)	27,294	15,559	10,126	1,520	89		
Service payment commitments	$ 7,580	$ 4,906	$ 2,038	$ 636			
Capital expenditure commitments	$ 69,288	$ 69,288					

Long-term debt-related commitments. We have long and short-term payment obligations under credit agreements such as our Senior Notes and revolving credit facilities. The preceding table shows our scheduled future maturities of long-term debt principal (including current maturities) for the periods indicated. See Note 9 for a description of these debt obligations and classification used for accounting purposes.

Operating lease commitments. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. The preceding table shows the minimum lease payment obligations under our third-party operating leases with terms in excess of one year for the periods indicated.

Our material agreements consist of operating leases, with original terms ranging from 5 to 24 years, for natural gas and NGL underground storage facilities. We generally have the option to renew these leases, under the terms of the agreements, for one or more renewal terms ranging from 2 to 10 years. In general, rent is determined by multiplying a storage quantity (typically in barrels) by a contractually stated price. Rental payments under our storage leases are escalated, as specified in the lease, to reflect increases in the market value of the storage capacity or to adjust for inflation. In general, contingent rental payments are assessed when our storage volumes exceed our storage allotment and are equal to the product of (i) a contractually stated price and (ii) the volume which exceeds our storage allotment.

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. Under certain of our natural gas and NGL storage lease agreements, we are required to perform routine maintenance on the storage facility. In addition, certain leases give us the option to increase storage capacity or fund major leasehold improvements. Maintenance, repairs and minor renewals are charged to operations as incurred. We have not made any major leasehold improvements with regards to our natural gas and NGL underground storage facilities during the years ended December 31, 2004, 2003 or 2002.

The operating lease commitments shown in the preceding table exclude the non-cash related party expense associated with various equipment leases contributed to us by EPCO at our formation for which EPCO has retained the liability (the “retained leases”). The retained leases are accounted for as operating leases by EPCO. EPCO’s minimum future rental payments under these leases are $2.1 million for each of the years 2005 through 2008, $0.7 million for each of the years 2009 through 2015 and $0.3 million for 2016.

EPCO has assigned to us the purchase options associated with the retained leases. During 2004 we purchased an isomerization unit and related equipment for $17.8 million pursuant to our purchase options, which prices approximated fair value. Should we decide to exercise all of the remaining purchase options associated with the retained leases (which are also at fair value), up to an additional $2.3 million would be payable in 2008 and $3.1 million in 2016.

Third-party lease and rental expense included in operating income for the years ended December 31, 2004, 2003 and 2002 was approximately $19.5 million, $17.8 million and $16.4 million, respectively.

Purchase obligations. We define purchase obligations as agreements to purchase goods or services that are enforceable and legally binding (unconditional) and that specify 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 several third-party suppliers. The purchase prices that we are generally 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. At December 31, 2004, we do not have any product purchase commitments with fixed or minimum pricing provisions having remaining terms in excess of one year. To the extent that variable price provisions exist in these contracts, our estimated future payment obligations are based on the contractual price under each contract for purchases made at December 31, 2004 applied to future volume commitments.

- *Service contract commitments*. We have long and short-term commitments to pay third-party service 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 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.

Litigation

We are sometimes named as a defendant in litigation relating to our normal business operations, including litigation related to various federal, state and local regulatory and environmental matters. Although we insure against various business risks, to the extent management believes 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 ordinary business activity. Management is not aware of any significant litigation, pending or threatened, that would have a significant adverse effect on our financial position or results of operations.

We own a facility that historically produced MTBE, a motor gasoline additive that enhances octane and is used in reformulated motor gasoline. We operated the facility, which is located within our Mont Belvieu complex. The production of MTBE was primarily driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990. 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, federal legislation has been drafted to ban MTBE and replace the oxygenate with renewable fuels such as ethanol.

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 which 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.

Performance Guaranty

In December 2004, our Independence Hub, LLC subsidiary entered into the Independence Hub Agreement (the "Agreement") with six oil and natural gas producers. The Agreement obligates Independence Hub, LLC (i) to construct an offshore platform production facility to process 850 MMcf/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 Independence Hub, LLC subsidiary under the Hub Agreement up to $397.5 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 $318 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 our share of the cost of constructing the platform in the very unlikely scenario where the six producers take over the construction of the platform facility. Our performance guarantee continues until the earlier to occur of (i) all of the guaranteed obligations of Independence Hub, LLC shall have been terminated or expired, or shall have been indefeasibly paid or otherwise performed or 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 will occur on or about November 1, 2006; therefore, we anticipate that the performance guaranty will exist until at least this forecast date.

In accordance with FIN 45, 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 current and other long-term liabilities on our Consolidated Balance Sheet at December 31, 2004.

17. SUPPLEMENTAL CASH FLOW DISCLOSURE

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,		
	2004	2003	2002
(Increase) decrease in:			
Accounts and notes receivable	$(453,904)	$ (54,388)	$(127,365)
Inventories	(44,202)	49,932	(84,254)
Prepaid and other current assets	2,726	11,073	15,340
Long-term receivables	611		
Other assets	(6,684)	(226)	(3,322)
Increase (decrease) in:			
Accounts payable	110,497	(6,720)	23,901
Accrued gas payable	286,089	128,050	262,527
Accrued expenses	8,800	(16,677)	7,884
Accrued interest	(199)	15,012	5,369
Other current liabilities	6,534	(4,196)	(6,921)
Other liabilities	(3,993)	(972)	(504)
Net effect of changes in operating accounts	$ (93,725)	$ 120,888	$ 92,655
Cash payments for interest, net of $2,766, $1,595 and $1,083 capitalized in 2004, 2003 and 2002, respectively	$ 135,797	$ 112,712	$ 82,535
Cash payments for federal and state income taxes	$ 182	$ 453	n/a

During 2004, we completed several business combinations, primarily the GulfTerra Merger and our purchase of certain midstream energy assets located in South Texas from El Paso. See Note 4 for the preliminary purchase price allocations related to these transactions which include non-cash consideration for equity interests issued and the fair values of assets acquired and liabilities assumed. In addition, see Note 10 for information regarding changes in our partners' equity accounts as a result of the GulfTerra Merger transactions, including amounts associated with unit awards and Series F2 convertible units.

We incurred liabilities for construction in progress and property additions that had not been paid at December 31, 2004, 2003 and 2002 of $62.4 million, $9.1 million and $6.5 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Statements of Consolidated Cash Flows. The increase in such amounts at December 31, 2004 compared to December 31, 2003 is primarily due our acquisition of GulfTerra, which had several large offshore projects.

On certain of our capital projects, third parties may be obligated to reimburse us for capital expenditures. As a result of completing the GulfTerra Merger, the number of such arrangements has increased, particularly for projects involving pipeline construction and production well tie-ins. In November 2004, Tennessee Gas Pipeline reimbursed us $7 million for construction costs incurred for our Independence Trail pipeline project, which is reflected as a source of investing cash inflows under the caption "Contributions in aid of construction" on our Statements of Consolidated Cash Flows. In addition to this reimbursement, we received $1.9 million, $0.9 million and $4 million as contributions in aid of construction during 2004, 2003 and 2002, respectively.

During 2003, we completed several business acquisitions, made adjustments to the 2002 purchase price allocation of the Mid-America and Seminole acquisitions and consolidated entities that had not been previously accounted for using the equity method. During 2002, we completed $1.8 billion in business acquisitions, the most significant of which were the acquisition of interests in the Mid-America and Seminole pipelines from Williams and propylene fractionation and NGL and petrochemical storage assets from Diamond-Koch. These transactions and events over the last three years affected various balance sheet categories summarized as follows:

	For Year Ended December 31, 2004	2003	2002
Current assets	$ 216,335	$ 24,960	$ 53,287
Property, plant and equipment	4,806,941	131,452	1,507,243
Investments in unconsolidated affiliates	160,075	(57,172)	7,550
Intangible assets	744,353	4,057	92,356
Goodwill	376,770	880	73,691
Deferred tax asset			17,307
Other assets	26,881	3,208	2,699
Current liabilities	(233,864)	(32,140)	(17,747)
Long-term debt	(2,015,583)		(60,000)
Other liabilities	(47,880)	(6,063)	(90)
Minority interest	26,590	(31,834)	(55,569)
Total	$ 4,060,618	$ 37,348	$ 1,620,727

Additionally, we record various financial instruments relating to commodity positions and interest rate hedging activities at their respective fair values using mark-to-market accounting. These amounts for 2004 and 2003 were negligible; however, during 2002, we recognized a net $10.2 million in non-cash mark-to-market decreases in the fair value of these instruments primarily in our commodity financial instruments portfolio.

Net income for 2004 includes a gain on sale of assets of approximately $15.1 million related to the satisfaction of certain requirements of a sale agreement whereby a 50% interest in Cameron Highway was sold. Approximately $10.1 million of this gain was the non-cash recognition of a receivable that is due no later than December 31, 2006 while $5.0 million of the gain was associated with a cash payment received during the fourth quarter of 2004.

Cash and cash equivalents (as shown on our Statements of Consolidated Cash Flows) excludes restricted cash amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for our physical purchase of natural gas made on the NYMEX exchange. The restricted cash balance at December 31, 2004 and 2003 was $26.2 million and $13.9 million, respectively.

18. 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 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 No. 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.

Due to the complexity of SFAS No. 133 (as amended and interpreted), the FASB is continuing to provide guidance regarding the implementation of this accounting standard. Since this guidance is still continuing, our conclusions about the application of SFAS No. 133 may be altered, which may result in adjustments being recorded in future periods as we adopt new FASB interpretations of this standard.

Interest rate risk hedging program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess the 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 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 climate.

Fair value hedges – Interest rate swaps. In January 2004, we entered into three interest rate swap agreements with an aggregate notional amount of $250 million in which we exchanged the payment of fixed rate interest on a portion of the principal outstanding under Senior Notes B and C for variable rate interest. During the fourth quarter of 2004, we entered into six additional interest rate swap agreements with an aggregate notional amount of $600 million related to a portion of the principal outstanding under Senior Notes G issued on October 4, 2004.

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 6.3%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 4.9%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 3.4%	$600 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these nine interest rate swaps as fair value hedges under SFAS No. 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 fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

These nine agreements have a combined notional amount of $850 million 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 LIBOR rates (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.

Total fair value of the interest rate swaps in effect at December 31, 2004 was a receivable of approximately $0.5 million with an offsetting increase in fair value of the underlying debt. Interest expense in our Statements of Consolidated Operations and Comprehensive Income for the year ended December 31, 2004 reflects a $9.1 million benefit from these swap agreements.

Cash flow hedges – Forward starting interest rate swaps. During the first nine months of 2004, we entered into eight forward starting interest rate swap transactions having an aggregate notional amount of $2 billion in anticipation of our financing activities associated with closing the GulfTerra Merger. Our purpose in entering into these transactions was to effectively hedge the underlying U.S. treasury rate related to our anticipated issuance of $2 billion in principal amount of fixed rate debt. On October 4, 2004, our Operating Partnership issued $2 billion of private debt securities under Senior Notes E, F, G and H. Each of the forward starting swaps was designated as a cash flow hedge under SFAS No. 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 net gain of $19.4 million from these settlements will be reclassified from Accumulated Other Comprehensive Income to reduce interest expense over the life of the associated debt.

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

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

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 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 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, 2004, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of natural gas cash flow and fair value hedges. 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 commodity financial instrument to reestablish the economic hedge to which the closed instrument relates.

We recorded $0.4 million of income related to our commodity hedging activities during 2004 and an expense of $0.6 million during 2003, which are included in our operating costs and expenses in the Statements of Consolidated Operations and Comprehensive Income.

During 2002, we recognized a loss of $51.3 million from our commodity hedging activities that was recorded as an increase in our operating costs and expenses. Beginning in late 2000 and extending through March 2002, a large number of our commodity hedging transactions were based on the historical relationship between natural gas and NGL prices. This type of hedging strategy utilized the forward sale of natural gas at a fixed price with the expected margin on the settlement of the position offsetting or mitigating changes in the anticipated margins on NGL marketing activities and the market values of our equity NGL production. Throughout 2001, this strategy proved very successful (as the price of natural gas declined relative to our fixed positions) and was responsible for most of the $101.3 million in commodity hedging income we recorded during 2001.

In late March 2002, the effectiveness of this strategy was reduced due to an unexpected rapid increase in natural gas prices whereby the loss in the value of our fixed-price natural gas financial instruments was not offset by increased natural gas processing margins. Due to the inherent uncertainty surrounding natural gas prices at the time, we decided that it was prudent to exit this strategy, and we did so by late April 2002. The increased ineffectiveness of this strategy is the primary reason for the $51.3 million in commodity hedging losses recorded during 2002.

We had a limited number of commodity financial instruments open at December 31, 2004 and 2003. The fair value of these open positions at December 31, 2004 and 2003 was an asset of $219 thousand and $4 thousand, respectively (both amounts based on market prices on these dates).

Effect of financial instruments on Accumulated Other Comprehensive Income (Loss)

The following table summarizes the effect of our cash flow hedging financial instruments on accumulated other comprehensive income (loss) since January 1, 2002.

		Interest Rate Fin. Instrs.		Accumulated Other Comprehensive Income (Loss) Balance
	Commodity Financial Instruments	Treasury Locks	Forward-Starting Interest Rate Swaps	
Balance, January 1, 2002		$ —		$ —
Change in fair value of treasury locks		(3,560)		(3,560)
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 treasury locks to interest expense		(418)		(418)
Reclassification of gain on settlement of forward-starting swaps to interest expense			(857)	(857)
Balance, December 31, 2004	$ 1,434	$ 4,572	$ 18,548	$ 24,554

During 2005, we will reclassify $0.4 million and $3.6 million from Accumulated Other Comprehensive Income as a reduction in interest expense from our treasury locks and forward-starting interest rate swaps, respectively. In addition, in the first quarter of 2005, we will record an approximate $1.6 million gain into income from Accumulated Other Comprehensive Income related to a commodity cash flow hedge acquired in the GulfTerra Merger. This gain is primarily due to an increase in fair value from that recorded for the commodity cash flow hedge at December 31, 2004.

Fair value information

Cash and cash equivalents, accounts receivable, accounts payable and accrued expenses are carried at amounts which reasonably approximate their fair value due to their short-term nature. The estimated fair value of our fixed rate debt is estimated 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 commodity and interest rate hedging financial instruments were developed using available market information and appropriate valuation techniques. The following table summarizes the estimated fair values of our various financial instruments at December 31, 2004 and 2003:

	December 31, 2004		December 31, 2003	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents	$ 50,713	$ 50,713	$ 44,317	$ 44,317
Accounts receivable	1,083,536	1,083,536	462,545	462,545
Commodity financial instruments (1)	3,904	3,904	358	358
Interest rate hedging financial instruments (2)	505	505		
Financial liabilities:				
Accounts payable and accrued expenses	1,466,115	1,466,115	799,456	799,456
Fixed-rate debt (principal amount)	3,725,469	3,922,459	1,734,000	1,849,327
Variable-rate debt	563,229	563,229	410,000	410,000
Commodity financial instruments (1)	3,685	3,685	355	355

(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 had not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

Counterparty risk

From time to time, we have credit risk with our counterparties in terms of settlement risk associated with financial instruments. On all transactions where we are exposed to credit risk, 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.

19. SEGMENT INFORMATION

Business segments are components of a business about which separate financial information is available. The components are regularly evaluated by the CEO of Enterprise GP in deciding how to allocate resources and in assessing performance. Generally, financial information is required to be reported on the basis that it is used internally for evaluating segment performance and deciding how to allocate resources to segments.

As a result of the GulfTerra Merger (see Note 4), we have reorganized our business activities into four reportable business segments, as discussed below. Our business segments are generally organized and managed according to the type of services rendered and products produced and/or sold. We have revised our prior segment information in order to conform to the current business segment operations and presentation.

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

The Offshore Pipelines & Services business segment consists of (i) approximately 1,150 miles of offshore natural gas pipelines strategically located to serve production areas in some of the most active drilling and development regions in the Gulf of Mexico, (ii) approximately 800 miles of Gulf of Mexico offshore crude oil pipeline systems and (iii) seven multi-purpose offshore hub platforms located in the Gulf of Mexico, which are included in our Offshore Pipelines & Services business segment.

The Onshore Natural Gas Pipelines & Services business segment consists of 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, this segment includes two salt dome natural gas storage facilities located in Mississippi, which are strategically located to serve the Northeast, Mid-Atlantic and Southeast domestic natural gas markets. This segment also includes leased natural gas storage facilities located in Texas and Louisiana.

The NGL Pipelines & Services business segment includes our (i) natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating approximately 12,775 miles and related storage facilities, which include our strategic Mid-America and Seminole NGL pipeline systems and (iii) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our import and export terminaling operations.

The Petrochemical Services business segment includes four propylene fractionation facilities, an isomerization complex, and an octane additive production facility. This segment also includes various petrochemical pipeline systems.

The Other non-segment category is presented for financial reporting purposes only to reflect the historical equity earnings we received from GulfTerra GP and our underlying investment in this entity at December 31, 2003. We acquired a 50% membership interest in GulfTerra GP on December 15, 2003 in connection with Step One of the GulfTerra Merger. Our 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.

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 affected by changes in the prices of these hydrocarbon products and by 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 impossible to 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 general economic conditions, reduced demand by consumers for the end products made with NGL products, increased competition from petroleum-based products due to the 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 also adversely affect our results of operations, cash flows and financial position.

Our revenues are derived from a wide customer base. All consolidated revenues were earned in the United States. Most of our plant-based operations are located either along the western Gulf Coast in Texas, Louisiana and Mississippi or in New Mexico. Our natural gas, NGL and oil pipelines and related operations 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 at our main office and service customers in a number of regions in the United States including the Gulf Coast, West Coast and Mid-Continent areas.

We evaluate segment performance based on segment 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.

We define total (or consolidated) segment gross operating margin as operating income before: (1) depreciation, depletion and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, 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 intercompany transactions.

Segment revenues 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 include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin. 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 a supplier of raw materials or a consumer 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. For example, we use the Promix NGL fractionator to process a portion of the mixed NGLs extracted by our gas plants. Another example is our use of the Dixie pipeline to transport propane sold to customers through our NGL marketing activities. See Note 14 for additional information regarding our related party relationships with unconsolidated affiliates.

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 segment assets is construction-in-progress. Segment assets represents those facilities and projects that contribute to gross operating margin and is net of accumulated depreciation on these assets. Since assets under construction generally do not contribute to segment gross operating margin, these assets are excluded from the business segment 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.

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The following table shows our measurement of total segment gross operating margin for the periods indicated:

	Year Ended December 31, 2004	2003	2002
Revenues (1)	$ 8,321,202	$ 5,346,431	$ 3,584,783
Less operating costs and expenses (1)	(7,904,336)	(5,046,777)	(3,382,839)
Add: Equity in income (loss) of unconsolidated affiliates (1)	52,787	(13,960)	35,253
Depreciation and amortization in operating costs and expenses (2)	193,734	115,643	86,028
Retained lease expense, net in operating expenses allocable to us and minority interest (3)	7,705	9,094	9,125
Gain on sale of assets in operating costs and expenses (2)	(15,901)	(16)	(1)
Total segment gross operating margin	$ 655,191	$ 410,415	$ 332,349

(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, 2004	2003	2002
Total segment gross operating margin	$ 655,191	$ 410,415	$ 332,349
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation and amortization in operating costs and expenses	(193,734)	(115,643)	(86,028)
Retained lease expense, net in operating costs and expenses	(7,705)	(9,094)	(9,125)
Gain on sale of assets in operating costs and expenses	15,901	16	1
Selling, general and administrative costs	(46,659)	(37,590)	(42,890)
Consolidated operating income	422,994	248,104	194,307
Other expense	(153,625)	(134,406)	(94,226)
Income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 269,369	$ 113,698	$ 100,081

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Information by segment, together with reconciliations to the consolidated totals, is presented in the following table:

	Business Segments						
	Offshore Pipeline & Services	Onshore Nat. Gas Pipelines & Services	NGL Pipelines & Services	Petrochem. Services	Non-Segmt. Other	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:							
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	3,654,596	782,999			4,782,206
Year ended December 31, 2002		295,709	2,246,266	560,091			3,102,066
Revenues from related parties:							
Year ended December 31, 2004	535	253,194	534,279	16,142			804,150
Year ended December 31, 2003		227,973	325,358	10,894			564,225
Year ended December 31, 2002		146,062	311,525	25,130			482,717
Intersegment and intrasegment revenues:							
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)	—
Year ended December 31, 2002		2,271	757,311	151,880		(911,462)	—
Total revenues:							
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
Year ended December 31, 2002		444,042	3,315,102	737,101		(911,462)	3,584,783
Equity in income (loss) in unconsolidated affiliates:							
Year ended December 31, 2004	8,859	772	9,898	1,233	$ 32,025		52,787
Year ended December 31, 2003	5,561	131	7,842	(27,441)	(53)		(13,960)
Year ended December 31, 2002	10,534	(58)	15,392	9,385			35,253
Gross operating margin by individual business segment and in total:							
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
Year ended December 31, 2002	10,535	22,110	181,928	117,776			332,349
Segment assets:							
At December 31, 2004	648,181	3,729,650	2,753,934	469,327		230,375	7,831,467
At December 31, 2003		220,922	2,183,485	484,666		74,432	2,963,505
Investments in and advances to unconsolidated affiliates:							
At December 31, 2004	319,463	5,251	173,883	20,567			519,164
At December 31, 2003	127,605	2,519	190,682	22,006	424,947		767,759
Intangible Assets:							
At December 31, 2004	200,047	425,806	303,459	51,289			980,601
At December 31, 2003			215,072	53,821			268,893
Goodwill:							
At December 31, 2004	62,348	290,397	32,763	73,690			459,198
At December 31, 2003			8,737	73,690			82,427

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 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.

20. CONDENSED FINANCIAL INFORMATION OF OPERATING PARTNERSHIP

The Operating Partnership and its subsidiaries conduct substantially all of our business. Currently, we have no independent operations and no material assets outside of those of the Operating Partnership. In December 2003, we restructured Enterprise GP's ownership interest in us and the Operating Partnership from a 1% ownership interest in us and 1.0101% ownership in the Operating Partnership to a 2% ownership in us. As a result, our effective ownership in the Operating Partnership increased from 98.9899% to 100%. For additional information regarding our capital structure, see Note 10.

At December 31, 2004, the Operating Partnership had $3.7 billion in outstanding debt securities represented by its Senior Notes A, B, C, D, E, F, G and H. We act as guarantor of all our Operating Partnership's consolidated debt obligations, with the exception of the Seminole Notes and the remaining amounts outstanding under GulfTerra's senior and 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 full and unconditional. For additional information regarding our consolidated debt obligations, see Note 9.

The number and dollar amounts of reconciling items between our consolidated financial statements and those of our Operating Partnership are insignificant. The primary reconciling items between the consolidated balance of the Operating Partnership and our consolidated balance sheet are treasury units we own directly and minority interest. The differences in consolidated net income are primarily dividends recognized by the 1999 Trust (which are eliminated in consolidation) and minority interest.

The following table shows condensed consolidated balance sheet data for the Operating Partnership at the dates indicated:

	December 31,	
	2004	2003
ASSETS		
Current assets	$ 1,425,574	$ 687,530
Property, plant and equipment, net	7,831,467	2,963,505
Investments in and advances to unconsolidated affiliates, net	519,164	767,759
Intangible assets, net	980,601	268,893
Goodwill	459,198	82,427
Deferred tax asset	6,467	10,437
Long-term receivables	14,931	
Other assets	43,208	22,610
Total	$ 11,280,610	$ 4,803,161
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	$ 1,582,911	$ 1,093,747
Long-term debt	4,266,236	1,899,548
Other long-term liabilities	63,521	14,081
Minority interest	73,858	89,216
Partners' equity	5,294,084	1,706,569
Total	$ 11,280,610	$ 4,803,161
Total Operating Partnership debt obligations guaranteed by us	$ 4,267,229	$ 2,114,000

The following table shows condensed consolidated statements of operations data for the Operating Partnership for the periods indicated:

	For Year Ended December 31, 2004	2003	2002
Revenues	$ 8,321,202	$ 5,346,431	$ 3,584,783
Costs and expenses	7,946,816	5,083,701	3,425,503
Equity in income (loss) of unconsolidated affiliates	52,787	(13,960)	35,253
Operating income	427,173	248,770	194,533
Other income (expense)	(153,251)	(133,798)	(93,810)
Income before provision for income taxes, minority interest and changes in accounting principles	273,922	114,972	100,723
Provision for income taxes	(3,761)	(5,293)	(1,634)
Income before minority interest and changes in accounting principles	270,161	109,679	99,089
Minority interest	(8,072)	(3,095)	(2,137)
Income before changes in accounting principles	262,089	106,584	96,952
Cumulative effect of changes in accounting principles	10,781		
Net income	$ 272,870	$ 106,584	$ 96,952

21. SUBSEQUENT EVENTS

January 2005 acquisition of El Paso’s interests in the Company and Enterprise GP by affiliates of EPCO

In January 2005, an affiliate of EPCO, acquired El Paso’s 9.9% membership interest in Enterprise GP and 13,454,499 of our common units from El Paso for approximately $425 million in cash. As a result of these transactions, EPCO and affiliates own 100% of the membership interests of Enterprise GP and approximately 37.4% of our total common units outstanding. El Paso no longer owns any interest in us or Enterprise GP.

February 2005 equity offering

In February 2005, we sold 17,250,000 common units (including the over-allotment amount of 2,250,000 common units which closed on March 11, 2005) to the public at an offering price of $27.05 per unit. Net proceeds from this offering, including Enterprise GP’s proportionate net capital contribution of $9.1 million, were approximately $456.5 million after deducting applicable underwriting discounts, commissions and estimated offering expenses of $19.7 million. The net proceeds from this offering, including Enterprise GP’s proportionate net capital contribution, were used to repay our 364-Day Acquisition Credit Facility, to temporarily reduce indebtedness outstanding under our Multi-Year Revolving Credit Facility and for general partnership purposes.

February 2005 private senior notes offering

On February 15, 2005, our Operating Partnership sold $500 million in principal amount of senior notes in a Rule 144A private placement offering, comprised of $250 million in principal amount of 10-year senior unsecured notes and $250 million in principal amount of 30-year senior unsecured notes. The 10-year notes (“Senior Notes I”) were issued at 99.379% of their principal amount and have fixed-rate interest of 5.00% and a maturity date of March 1, 2015. The 30-year notes (“Senior Note J”) were issued at 98.691% of their principal amount and have fixed-rate interest of 5.75% and a maturity date of March 1, 2035. The Operating Partnership used the net proceeds from the issuance of Senior Notes I and J to repay $350 million of indebtedness outstanding under Senior Notes A which was due on March 15, 2005 and the remaining proceeds for general partnership purposes, including the temporary repayment of indebtedness outstanding under the Multi-Year Revolving Credit Facility.

March 2005 universal shelf registration statement

In March 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of partnership equity and public debt obligations. In connection with this registration statement, we also registered for resale 36,572,122 common units currently owned by Shell and 4,427,878 common units that had been sold by Shell to Kayne Anderson MLP Investment Company in December 2004. We are obligated to register the resale of these common units under a registration rights agreement we executed with Shell in connection with our acquisition of certain of Shell's Gulf Coast midstream energy businesses in September 1999.

Non-Public Investigation by the Bureau of Competition of the Federal Trade Commission

On February 24, 2005, an affiliate of EPCO, Enterprise GP Holdings, L.P., acquired TEPPCO GP from Duke Energy Field Services, LLC. TEPPCO GP owns a 2% general partner interest in and is the general partner of TEPPCO. On March 11, 2005, the Bureau of Competition of the Federal Trade Commission delivered written notice to Enterprise GP Holdings, L.P.'s legal advisor that it was conducting a non-public investigation to determine whether Enterprise GP Holdings' acquisition of TEPPCO GP may substantially lessen competition. No filings were required under the Hart-Scott-Rodino Act in connection with Enterprise GP Holdings' purchase of TEPPCO GP. EPCO and its affiliates may receive similar inquiries from other regulatory authorities. EPCO and its affiliates, including us, intend to cooperate fully with any such investigations and inquiries.

22. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table contains selected quarterly financial data for 2004 and 2003 (dollars in thousands, except per unit amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2004:				
Revenues	$ 1,704,890	$ 1,713,346	$ 2,040,271	$ 2,862,695(1)
Operating income	87,314	65,051	93,209	175,284(1)
Income before changes in accounting principles	51,528	33,075	57,523	115,354(1)
Net income	58,541	33,075	61,291	115,354(1)
Income per unit before changes in accounting principles:				
Basic	$ 0.24	$ 0.11	$ 0.20	$ 0.28
Diluted	$ 0.23	$ 0.11	$ 0.20	$ 0.28
Net income per unit:				
Basic	$ 0.24	$ 0.11	$ 0.21	$ 0.28
Diluted	$ 0.23	$ 0.11	$ 0.21	$ 0.28
For the Year Ended December 31, 2003:				
Revenues	$ 1,481,586	$ 1,210,659	$ 1,234,780	$ 1,419,406
Operating income	85,032	66,348	30,622(2)	66,102
Net income (loss)	40,505	33,105	(3,261)(2)	34,197
Net income per unit:				
Basic	$ 0.20	$ 0.15	$ (0.04)(2)	$ 0.13
Diluted	$ 0.19	$ 0.14	$ (0.04)(2)	$ 0.13

(1) Revenues, operating income, income before changes in accounting principles and net income increased as a result of the GulfTerra Merger, which was completed on September 30, 2004. Net income for the fourth quarter of 2004 also includes a gain on sale of assets of approximately $15.1 million related to the satisfaction of certain requirements of a sale agreement whereby a 50% interest in Cameron Highway was sold. Approximately $10.1 million of this gain was the non-cash recognition of a receivable that is due no later than December 31, 2006 while $5.0 million of the gain was associated with a cash payment received during the fourth quarter of 2004.

(2) Equity earnings from BEF for the third quarter of 2003 include a $22.5 million asset impairment charge. This non-cash charge resulted in our posting a net loss for the quarter.

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					
2004	$ 20,423	$ 4,840	$ 4,158(2)	$ (5,112)(3)	$ 24,310
2003	21,196	1,239	71	(2,083)(1,3)	20,423
2002	20,642	14	5,251(1)	(4,711)(3)	21,196
Inventories					
Allowance for uncollectible imbalances					
2004			8,463(8)		8,463
Other current assets					
Additional credit reserve for Enron					
2002	4,305			(4,305)(1)	
Other current liabilities					
Reserve for environmental liabilities					
2004	9		115	(9)	115
2003	9				9
2002			102	(93)	9
Reserve for inventory gains and losses(5)					
2004	2,700	900		(2,850)	750
2003	1,271	3,000		(1,571)	2,700
2002	2,029	500		(1,258)	1,271
Reserve for BEF turnaround accrual(6)					
2004	2,013			(2,013)	
2003			2,124(4)	(111)	2,013
Other long-term liabilities					
Reserve for environmental liabilities					
2004	1,133		21,136(7)	(265)	22,004
2003	135		1,061	(63)	1,133
2002		45	90		135
Reserve for BEF turnaround accrual(6)					
2004	5,001			(5,001)	
2003			5,001(4)		5,001

(1) In December 2001, Enron North America filed for protection under Chapter 11 of the U.S. Bankruptcy Code. As a result, we established an initial $10.6 million reserve for amounts owed to us by Enron. The Enron amounts were unsecured and the amount that we may ultimately recover, if any, is not presently determinable. Of the $10.6 million reserve established at December 31, 2001, $6.2 million offset billed amounts due from Enron recorded in "*Accounts Receivable-trade*". The remaining initial $4.3 million reserve offset various unbilled commodity financial instrument positions, which were reclassified to "*Additional credit reserve from Enron*." As the unbilled amounts were invoiced in early 2002, the reserve was reclassified from "*Additional credit reserve from Enron*" to "*Allowance for doubtful accounts*." During 2003, the overall Enron reserve was lowered to $8.6 million as a result of management determination that a higher percentage of the billed amounts would be collected than was originally anticipated.

(2) The allowance account was increased in 2004 as a result of accounts acquired in the GulfTerra Merger.

(3) In the normal course of business, we charged the allowance account for customer accounts that have been deemed uncollectible.

(4) We acquired an additional 33.3% interest in BEF on September 30, 2003. As a result, we began consolidating its accounts with those of our own. The beginning balances of these accounts reflect the initial September 30, 2003 balances we consolidated.

(5) In general, the inventory gain/loss reserve was established to cover anticipated net losses attributable to the storage of NGL and petrochemical products in underground storage caverns. The reserve is increased based on management's estimate of net product storage losses. Product losses are charged against and reduce the reserve. Conversely, product gains increase the reserve. Management regularly reviews the status of the reserve and determines the appropriate level based on historical and anticipated storage well activity.

(6) As noted in footnote "4" above, we began consolidating BEF's accounts with those of our own on September 30, 2003. On January 1, 2004, BEF changed its accounting method for planned major maintenance costs from accrue-in-advance to expense-as-incurred to conform to our accounting method. These reserves represent the short and long-term components of such estimates made under the accrue-in-advance method.

(7) The environmental reserve account was increased in 2004 as a result of accounts acquired in the GulfTerra Merger.

(8) The allowance for natural gas imbalances account was created as a result of accounts acquired in the GulfTerra Merger.

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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, in the City of Houston, State of Texas on March 15, 2005.

ENTERPRISE PRODUCTS PARTNERS L.P. (A Delaware Limited Partnership)

By: **Enterprise Products GP, LLC,** as general partner

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

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 March 15, 2005.

Signature	Title (with Enterprise Products GP, LLC)
/s/ Dan L. Duncan Dan L. Duncan	Chairman and Director
/s/ O.S. Andras O. S. Andras	Vice Chairman and Director
/s/ Robert G. Phillips Robert G. Phillips	President, Chief Executive Officer and Director
/s/ Michael A. Creel Michael A. Creel	Executive Vice President and Chief Financial Officer
/s/ Michael J. Knesek Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer
/s/ Dr. Ralph S. Cunningham Dr. Ralph S. Cunningham	Director
/s/ Lee W. Marshall, Sr. Lee W. Marshall, Sr.	Director
/s/ W. Matt Ralls W. Matt Ralls	Director
/s/ Richard S. Snell Richard S. Snell	Director

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EXHIBIT INDEX

Exhibit No.	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 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 filed December 27, 2004).

Exhibit No.	Exhibit*
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	Fourth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of October 1, 2004 (incorporated by reference to Exhibit 3.1 to Form 8-K filed October 6, 2004).
3.2	Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, among Duncan Family Interests, Inc., Dan Duncan LLC, and GulfTerra GP Holding Company dated September 30, 2004 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 30, 2004).
3.3	Application for Admission by Enterprise GP Holdings L.P. as a Substituted Member of Enterprise Products GP, LLC (incorporated by reference to Exhibit 3.1 to Form 8-K filed January 18, 2005).
3.4	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 3.3 to Form 10-Q filed August 9, 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 Note representing $350 million principal amount of 8.25% Senior Notes due 2005 (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 10, 2000).
4.7	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).
4.8	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).
4.9	Contribution Agreement dated September 17, 1999 (incorporated by reference to Exhibit “B” to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.10	Registration Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit “E” to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.11	Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit “C” to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.12	Amendment No. 1, dated September 12, 2003, to Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit 4.1 to Form 8-K filed September 15, 2003).
4.13	Agreement dated as of March 4, 2004 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, 2004).
4.14	$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, Mizuho Corporate Bank, Ltd., SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents, Wachovia Capital Markets, LLC, CitiGroup Global Markets Inc. and JPMorgan Chase Securities, Inc., as Joint Lead Arrangers and Joint Book Runners

Exhibit No.	Exhibit*
	(incorporated by reference to Exhibit 4.1 to Form 8-K filed on August 30, 2004).
4.15	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 4.1, above (incorporated by reference to Exhibit 4.2 to Form 8-K filed on August 30, 2004).
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 4.3, 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 A 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, 2004).
4.24	Global Note representing $500 million principal amount of 5.600% Series A 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, 2004).
4.25	Global Note representing $150 million principal amount of 5.600% Series A 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, 2004).
4.26	Global Note representing $350 million principal amount of 6.650% Series A 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, 2004.
4.27#	Global Note representing $500 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee.
4.28	Registration Rights Agreement dated as of October 4, 2004, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.17 to Form 8-K filed on October 6, 2004).
4.29	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).

Exhibit No.	Exhibit*
4.30	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).
4.31	Rule 144A Global Note representing $250,000,000 principal amount of 5.00% Series A Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed on March 3, 2005).
4.32	Rule 144A Note representing $250,000,000 principal amount of 5.75% Series A Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed on March 3, 2005).
4.33	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).
4.34	Exchange and Registration Rights Agreement, dated as of September 30, 2004, among GulfTerra GP Holding Company, Enterprise Products GP, LLC and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 4.1 to Form 8-K filed on September 30, 2004).
4.35	Performance Guaranty dated as of September 30, 2004, by DFI Delaware Holdings L.P. in favor of GulfTerra GP Holding Company (incorporated by reference to Exhibit 4.2 to Form 8-K filed on September 30, 2004).
4.36	Registration Rights Agreement, dated as of September 30, 2004, between El Paso Corporation and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 4.3 to Form 8-K filed on September 30, 2004).
4.37	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).
4.38	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).
4.39	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).
4.40	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).
4.41	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).
4.42	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 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).

Exhibit No.	Exhibit*
4.43	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).
4.44	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).
4.45	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).
4.46	Indenture dated as of July 3, 2003, by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (Filed as Exhibit 4.L to GulfTerra's 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.47	First 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).
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	Partnership Agreement among Sun BEF, Inc., Liquid Energy Fuels Corporation and Enterprise Products Company dated May 1, 1992 (incorporated by reference to Exhibit 10.5 to Registration Statement on Form S-1 filed May 13, 1998).
10.3	Propylene Facility and Pipeline Agreement between Enterprise Petrochemical Company and Hercules Incorporated dated December 13, 1978 (incorporated by reference to Exhibit 10.9 to Registration Statement on Form S-l filed May 13, 1998).
10.4	Restated Operating Agreement for the Mont Belvieu Fractionation Facilities Chambers County, Texas among Enterprise Products Company, Texaco Producing Inc., El Paso Hydrocarbons Company and Champlin Petroleum Company dated July 17, 1985 (incorporated by reference to Exhibit 10.10 to Registration Statement on Form S-l/A filed July 8,1998).
10.5	Amendment to Propylene Facility and Pipeline Agreement and Propylene Sales Agreement between HIMONT U.S.A., Inc. and Enterprise Products Company dated January 1, 1993 (incorporated by reference to Exhibit 10.12 to Registration Statement on Form S-l/A filed July 8, 1998).
10.6	Amendment to Propylene Facility and Pipeline Agreement and Propylene Sales Agreement between HIMONT U.S.A., Inc. and Enterprise Products Company dated January 1, 1995 (incorporated by reference to Exhibit 10.13 to Registration Statement on Form S-l/A filed July 8, 1998).
10.7	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).
10.8 ***	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).
10.9 ***	Form of Option Grant Award under 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).
10.10***	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).
10.11***	Letter Agreement dated September 30, 2004, among Enterprise Products Partners L.P., GulfTerra Energy Partners, L.P. and Bart Heijermans (incorporated by reference to Exhibit 10.1 to Form 8-K/A-2 filed on October 18, 2004).
10.12***	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

Exhibit No.	Exhibit*
	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).
10.13	Second Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products OLPGP, Inc., dated effective as of October 1, 2004 (incorporated by reference to Exhibit 10.1 to Form 8-K filed October 27, 2004).
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2004, 2003, 2002, 2001 and 2000.
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, 2004 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, 2004 annual report on Form 10-K.
32.1#	Section 1350 certification of Robert G. Phillips for the December 31, 2004 annual report on Form 10-K.
32.2#	Section 1350 certification of Michael A. Creel for the December 31, 2004 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.

EXHIBIT 4.27

BOOK — ENTRY SECURITY

UNLESS THIS CERTIFICATE IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY (“DTC”) (55 WATER STREET, NEW YORK, NEW YORK 10041) TO THE COMPANY OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE OR PAYMENT, AND ANY CERTIFICATE ISSUED IS REGISTERED IN THE NAME OF CEDE & CO. OR SUCH OTHER NAME AS MAY BE REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC (AND ANY PAYMENT IS MADE TO CEDE & CO. OR SUCH OTHER ENTITY AS MAY BE REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL INASMUCH AS THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN.

TRANSFERS OF THIS GLOBAL SECURITY SHALL BE LIMITED TO TRANSFERS IN WHOLE, BUT NOT IN PART, TO NOMINEES OF DTC OR TO A SUCCESSOR THEREOF OR SUCH SUCCESSOR’S NOMINEE AND TRANSFERS OF PORTIONS OF THIS GLOBAL SECURITY SHALL BE LIMITED TO TRANSFERS MADE IN ACCORDANCE WITH THE RESTRICTIONS SET FORTH IN THE INDENTURE REFERRED TO HEREIN.

Principal Amount

No. E-2

$500,000,000, which amount may be
increased or decreased by the Schedule
of Increases and Decreases in Global Security attached hereto.

ENTERPRISE PRODUCTS OPERATING L.P.

4.625% SERIES B SENIOR NOTES DUE 2009

CUSIP 293791 AM 1

ENTERPRISE PRODUCTS OPERATING L.P., a Delaware limited partnership (the “Company,” which term includes any successor under the Indenture hereinafter referred to), for value received, hereby promises to pay to Cede & Co. or its registered assigns, the principal sum of Five Hundred Million ($500,000,000) U.S. dollars, or such greater or lesser principal sum as is shown on the attached Schedule of Increases and Decreases in Global Security, on October 15, 2009 in such coin and currency of the United States of America as at the time of payment shall be legal tender for the payment of public and private debts, and to pay interest at an annual rate of 4.625% payable on April 15 and October 15 of each year, to the person in whose name the Security is registered at the close of business on the record date for such interest, which shall be the preceding April 1 and October 1 (each, a “Regular Record Date”), respectively, payable commencing on April 15, 2005, with interest accruing from October 4, 2004, or the most recent date to which interest shall have been paid.

Reference is made to the further provisions of this Security set forth on the reverse hereof. Such further provisions shall for all purposes have the same effect as though fully set forth at this place.

The statements in the legends set forth in this Security are an integral part of the terms of this Security and by acceptance hereof the Holder of this Security agrees to be subject to, and bound by, the terms and provisions set forth in each such legend.

This Security is issued in respect of a series of Debt Securities of an initial aggregate of $500 million in principal amount designated as the 4.625% Series B Senior Notes due 2009 of the Company and is governed by the Indenture dated as of October 4, 2004 (the “Original Indenture”), duly executed and delivered by the Company, as issuer, and Enterprise Products Partners L.P., as parent guarantor (the “Parent Guarantor”), to Wells Fargo Bank, National Association, as trustee (the “Trustee”), as supplemented by the Second Supplemental Indenture dated as of October 4, 2004, duly executed by the Company, the Parent Guarantor and the Trustee (the “Second Supplemental Indenture”, and together with the Original Indenture, the “Indenture”). The terms of the Indenture are incorporated herein by reference. This Security shall in all respects be entitled to the same benefits as definitive Securities under the Indenture.

If and to the extent any provision of the Indenture limits, qualifies or conflicts with any other provision of the Indenture that is required to be included in the Indenture or is deemed applicable to the Indenture by virtue of the provisions of the Trust Indenture Act of 1939, as amended (the “TIA”), such required provision shall control.

The Company hereby irrevocably undertakes to the Holder hereof to exchange this Security in accordance with the terms of the Indenture without charge.

This Security shall not be valid or become obligatory for any purpose until the Trustee’s Certificate of Authentication hereon shall have been manually signed by the Trustee under the Indenture.

IN WITNESS WHEREOF, the Company has caused this instrument to be duly executed by its sole General Partner.

Dated: March 7, 2005

ENTERPRISE PRODUCTS OPERATING L.P.

By: Enterprise Products OLPGP, Inc.
its General Partner

By: /s/ Richard H. Bachmann
Name: Richard H. Bachmann
Title: Executive Vice President

TRUSTEE'S CERTIFICATE OF AUTHENTICATION:

This is one of the Debt Securities of the series designated herein referred to in the within-mentioned Indenture.

WELLS FARGO BANK, NATIONAL ASSOCIATION,
as Trustee

By: /s/ Melissa Scott
Authorized Signatory

REVERSE OF BOOK — ENTRY SECURITY

ENTERPRISE PRODUCTS OPERATING L.P.

4.625% SERIES B SENIOR NOTES DUE 2009

This Security is one of a duly authorized issue of debentures, notes or other evidences of indebtedness of the Company (the "Debt Securities") of the series hereinafter specified, all issued or to be issued under and pursuant to the Indenture, to which Indenture reference is hereby made for a description of the rights, limitations of rights, obligations, duties and immunities thereunder of the Trustee, the Company, the Parent Guarantor and the Holders of the Debt Securities. The Debt Securities may be issued in one or more series, which different series may be issued in various aggregate principal amounts, may mature at different times, may bear interest (if any) at different rates, may be subject to different sinking, purchase or analogous funds (if any) and may otherwise vary as provided in the Indenture. This Security is one of a series designated as the 4.625% Series B Senior Notes due 2009 of the Company, in initial aggregate principal amount of $500 million (the "Securities").

1. *Interest*.

The Company promises to pay interest on the principal amount of this Security at the rate of 4.625% per annum.

The Company will pay interest semi-annually on April 15 and October 15 of each year (each an "Interest Payment Date"), commencing April 15, 2005. Interest on the Securities will accrue from the most recent date to which interest has been paid or, if no interest has been paid on the Securities, from October 4, 2004. Interest will be computed on the basis of a 360-day year consisting of twelve 30-day months. The Company shall pay interest (including post-petition interest in any proceeding under any applicable bankruptcy laws) on overdue installments of interest (without regard to any applicable grace period) and on overdue principal and premium, if any, from time to time on demand at the same rate per annum, in each case to the extent lawful.

2. *Method of Payment*.

The Company shall pay interest on the Securities (except Defaulted Interest) to the persons who are the registered Holders at the close of business on the Regular Record Date immediately preceding the Interest Payment Date. Any such interest not so punctually paid or duly provided for ("Defaulted Interest") may be paid to the persons who are registered Holders at the close of business on a special record date for the payment of such Defaulted Interest, or in any other lawful manner not inconsistent with the requirements of any securities exchange on which such Securities may then be listed if such manner of payment shall be deemed practicable by the Trustee, as more fully provided in the Indenture. The Company shall pay principal, premium, if any, and interest in such coin or currency of the United States of America as at the time of payment shall be legal tender for payment of public and private debts. Payments in respect of a Global Security (including principal, premium, if any, and interest) will be made by wire transfer of immediately available funds to the accounts specified by the Depositary.

Payments in respect of Securities in definitive form (including principal, premium, if any, and interest) will be made at the office or agency of the Company maintained for such purpose within The City of New York, which initially will be at the corporate trust office of the Trustee located at 45 Broadway, 12th Floor, New York, New York 10002, or, at the option of the Company, payment of interest may be made by check mailed to the Holders on the relevant record date at their addresses set forth in the Debt Security Register of Holders or at the option of the Holder, payment of interest on Securities in definitive form will be made by wire transfer of immediately available funds to any account maintained in the United States, provided such Holder has requested such method of payment and provided timely wire transfer instructions to the paying agent. The Holder must surrender this Security to a paying agent to collect payment of principal.

3. *Paying Agent and Registrar*.

Initially, Wells Fargo Bank, National Association will act as paying agent and Registrar. The Company may change any paying agent or Registrar at any time upon notice to the Trustee and the Holders. The Company may act as paying agent.

4. *Indenture*.

This Security is one of a duly authorized issue of Debt Securities of the Company issued and to be issued in one or more series under the Indenture.

Capitalized terms herein are used as defined in the Indenture unless otherwise defined herein. The terms of the Securities include those stated in the Original Indenture, those made part of the Indenture by reference to the TIA, as in effect on the date of the Original Indenture, and those terms stated in the Second Supplemental Indenture. The Securities are subject to all such terms, and Holders of Securities are referred to the Original Indenture, the Second Supplemental Indenture and the TIA for a statement of them. The Securities of this Series B are general unsecured obligations of the Company limited to an initial aggregate principal amount of $500 million; *provided*, *however*, that the authorized aggregate principal amount of such series may be increased from time to time as provided in the Second Supplemental Indenture.

5. *Redemption*.

Following the occurrence of the Special Mandatory Redemption Trigger, the Company shall redeem the Securities as a whole, upon notice as provided in Section 3.04 of the Original Indenture, at a redemption price equal to 101% of the principal amount thereof plus accrued and unpaid interest to the Redemption Date. Notwithstanding the provisions of Section 3.03 of the Original Indenture, notice of such mandatory redemption shall be given to each Holder within ten days of the date of the Special Mandatory Redemption Trigger in the manner provided in Section 13.03 of the Original Indenture, and such notice shall state, in addition to the matters prescribed in Section 3.03 of the Original Indenture, that the Special Mandatory Redemption Trigger has occurred and that all of the Notes will be redeemed on the Redemption Date set forth in such notice, which Redemption Date shall be no earlier than 15 days and no later than 30 days from the date such notice is mailed.

For purposes of the preceding paragraph, the following definitions are applicable:

"GulfTerra" means GulfTerra Energy Partners, L.P., a Delaware limited partnership.

"Merger Agreement" means the Merger Agreement dated December 15, 2003, among the Parent Guarantor, Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra and GulfTerra Energy Company, L.L.C., as amended by Amendment No. 1 thereto dated August 31, 2004.

"Special Mandatory Redemption Trigger" means the earliest to occur of the following three events:

(1) December 31, 2004, if on or before such date the Parent Guarantor has not completed the acquisition of GulfTerra (the "GulfTerra Acquisition") in conformity in all material respects with the terms and upon satisfaction of all material conditions of the Merger Agreement (after giving effect to any amendment, waiver or modification to any term or condition, which amendment, waiver or modification does not have a material adverse effect on Holders of the Notes);

(2) the Parent Guarantor has abandoned the GulfTerra Acquisition; or

(3) the Merger Agreement has terminated.

The Securities are redeemable, at the option of the Company, at any time in whole, or from time to time in part, at a redemption price (the "Make-Whole Price") equal to the greater of: (i) 100% of the principal amount of the Securities to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest (at the rate in effect on the date of calculation of the redemption price) on the Securities (exclusive of interest accrued to the Redemption Date) discounted to the Redemption Date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Yield plus 25 basis points; plus, in either case, accrued interest to the Redemption Date.

The actual Make-Whole Price, calculated as provided above, shall be calculated and certified to the Trustee and the Company by the Independent Investment Banker. For purposes of determining the Make-Whole Price, the following definitions are applicable:

"Treasury Yield" means, with respect to any Redemption Date applicable to the Securities, the rate per annum equal to the semi-annual equivalent yield to maturity (computed as of the third Business Day immediately preceding such Redemption Date) of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the applicable Comparable Treasury Price for the Redemption Date.

"Comparable Treasury Issue" means the United States Treasury security selected by the Independent Investment Banker as having a maturity comparable to the remaining term of the Securities that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining terms of the Securities; *provided, however,* that if no maturity is within three months before or after the maturity date for the Securities, yields for the two published maturities most closely corresponding to such United States Treasury security will be determined and the treasury rate will be interpolated or extrapolated from those yields on a straight line basis rounding to the nearest month.

"Independent Investment Banker" means either Wachovia Capital Markets, LLC (and its successors) or Citigroup Global Markets, Inc. (and its successors), or, if neither such firm is willing and able to select the applicable Comparable Treasury Issue, an independent investment banking institution of national standing appointed by the Trustee and reasonably acceptable to the Issuer.

"Comparable Treasury Price" means, with respect to any Redemption Date, (a) the bid price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) at 4:00 p.m. on the third Business Day preceding the Redemption Date, as set forth on "Telerate Page 500" (or such other page as may replace Telerate Page 500), or (b) if such page (or any successor page) is not displayed or does not contain such bid prices at such time, the average of the Reference Treasury Dealer Quotations obtained by the Trustee for the Redemption Date.

"Reference Treasury Dealer" means (a) Wachovia Capital Markets, LLC (and its successors) and (b) one other primary U.S. government securities dealer in New York City selected by the Independent Investment Banker (each, a "Primary Treasury Dealer"); *provided*, *however*, that if either of the foregoing shall cease to be a Primary Treasury Dealer, the Company will substitute therefor another Primary Treasury Dealer.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any Redemption Date for the Securities, an average, as determined by the Trustee, of the bid and asked prices for the Comparable Treasury Issue for the Securities (expressed in each case as a percentage of its principal amount) quoted in writing to the Trustee by such Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding such Redemption Date.

Except as set forth above, the Securities will not be redeemable prior to their Stated Maturity and will not be entitled to the benefit of any sinking fund.

Securities called for redemption become due on the Redemption Date. Notices of optional redemption will be mailed at least 30 but not more than 60 days before the Redemption Date to each Holder of the Securities to be redeemed at its registered address, and notices of mandatory redemption will be mailed at least 15 but not more than 30 days before the Redemption Date to all Holders at their respective registered addresses. The notice of redemption for the Securities will state, among other things, the amount of Securities to be redeemed, the Redemption Date, the redemption price (or the method of calculating such redemption price) and the place(s) that payment will be made upon presentation and surrender of Securities to be redeemed. Unless the Company defaults in payment of the redemption price, interest will cease to accrue on any Securities that have been called for redemption at the Redemption Date. If less than all the Securities are redeemed at any time, the Trustee will select the Securities to be redeemed on a pro rata basis or by any other method the Trustee deems fair and appropriate.

The Securities may be redeemed in part in multiples of $1,000 only. Any such redemption will also comply with Article III of the Indenture.

6. *Denominations; Transfer; Exchange*.

The Securities are to be issued in registered form, without coupons, in denominations of $1,000 and integral multiples of $1,000 in excess thereof. A Holder may register the transfer of, or exchange, Securities in accordance with the Indenture. The Registrar may require a Holder, among other things, to furnish appropriate endorsements and transfer documents and to pay any taxes and fees required by law or permitted by the Indenture.

7. *Person Deemed Owners*.

The registered Holder of a Security may be treated as the owner of it for all purposes.

8. *Amendment; Supplement; Waiver*.

Subject to certain exceptions, the Indenture may be amended or supplemented, and any existing Event of Default or compliance with any provision may be waived, with the consent of the Holders of a majority in principal amount of the Outstanding Debt Securities of each Series B affected. Without consent of any Holder of a Security, the parties thereto may amend or supplement the Indenture to, among other things, cure any ambiguity or omission, to correct any defect or inconsistency, or to make any other change that does not adversely affect the rights of any Holder of a Security. Any such consent or waiver by the Holder of this Security (unless revoked as provided in the Indenture) shall be conclusive and binding upon such Holder and upon all future Holders and owners of this Security and any Securities which may be issued in exchange or substitution herefor, irrespective of whether or not any notation thereof is made upon this Security or such other Securities.

9. *Defaults and Remedies*.

Certain events of bankruptcy or insolvency are Events of Default that will result in the principal amount of the Securities, together with premium, if any, and accrued and unpaid interest thereon, becoming due and payable immediately upon the occurrence of such Events of Default. If any other Event of Default with respect to the Securities occurs and is continuing, then in every such case the Trustee or the Holders of not less than 25% in aggregate principal amount of the Securities then Outstanding may declare the principal amount of all the Securities, together with premium, if any, and accrued and unpaid interest thereon, to be due and payable immediately in the manner and with the effect provided in the Indenture. Notwithstanding the preceding sentence, however, if at any time after such a declaration of acceleration has been made, the Holders of a majority in principal amount of the Outstanding Securities, by written notice to the Trustee, may rescind such declaration and annul its consequences if the rescission would not conflict with any judgment or decree of a court already rendered and if all Events of Default with respect to the Securities, other than the nonpayment of the principal, premium, if any, or interest which has become due solely by such declaration acceleration, shall have been cured or shall have been waived. No such rescission shall affect any subsequent default or shall impair any right consequent thereon. Holders of Securities may not enforce the Indenture or the Securities except as provided in the Indenture. The Trustee may require indemnity or security satisfactory to it before it enforces the Indenture or the Securities. Subject to certain limitations, Holders of a majority in aggregate principal amount of the Securities then outstanding may direct the Trustee in its exercise of any trust or power.

10. *Registration Rights*.

The Holder of this Security may be entitled to the benefits of the Registration Rights Agreement (the "Registration Rights Agreement") dated as of October 4, 2004, by and among the Company, the Parent Guarantor and the Initial Purchasers named therein. In certain events, the Company shall be required to pay to each affected Holder additional interest on the Securities, on the terms and subject to the conditions of the Registration Rights Agreement, and all references to "interest" herein include any such additional interest unless the context otherwise requires.

11. *Trustee Dealings with Company*.

The Trustee under the Indenture, in its individual or any other capacity, may make loans to, accept deposits from, and perform services for the Company or its Affiliates or any subsidiary of the Company's Affiliates, and may otherwise deal with the Company or its Affiliates as if it were not the Trustee.

12. *Authentication*.

This Security shall not be valid until the Trustee signs the certificate of authentication on the other side of this Security.

13. *Abbreviations and Defined Terms*.

Customary abbreviations may be used in the name of a Holder of a Security or an assignee, such as: TEN COM (tenant in common), TEN ENT (tenants by the entireties), JT TEN (joint tenants with right of survivorship and not as tenants in common), CUST (Custodian), and U/G/M/A (Uniform Gifts to Minors Act).

14. *CUSIP Numbers*.

Pursuant to a recommendation promulgated by the Committee on Uniform Note Identification Procedures, the Company has caused CUSIP numbers to be printed on the Securities as a convenience to the Holders of the Securities. No representation is made as to the accuracy of such number as printed on the Securities and reliance may be placed only on the other identification numbers printed hereon.

15. *Absolute Obligation*.

No reference herein to the Indenture and no provision of this Security or the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of, premium, if any, and interest on this Security in the manner, at the respective times, at the rate and in the coin or currency herein prescribed.

16. *No Recourse*.

The General Partner and the general partner of the Parent Guarantor and their respective directors, officers, employees and members, as such, shall have no liability for any obligations of any Guarantor or the Issuer under the Securities, the Indenture or any Guarantee or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each Holder by accepting the Securities waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Securities.

17. *Governing Law*.

This Security shall be construed in accordance with and governed by the laws of the State of New York.

18. *Guarantee*.

The Securities are fully and unconditionally guaranteed on an unsecured, unsubordinated basis by the Parent Guarantor as set forth in Article XIV of the Indenture, as noted in the Notation of Guarantee to this Security, and under certain circumstances set forth in the Original Indenture one or more Subsidiaries of the Parent Guarantor may be required to join in such guarantee.

19. *Reliance*.

The Holder, by accepting this Security, acknowledges and affirms that (i) it has purchased the Security in reliance upon the separateness of Parent Guarantor and the general partner of Parent Guarantor from each other and from any other Persons, including EPCO, Inc., and (ii) Parent Guarantor and the general partner of Parent Guarantor have assets and liabilities that are separate from those of other Persons, including EPCO, Inc.

NOTATION OF GUARANTEE

The Parent Guarantor (which term includes any successor Person under the Indenture), has fully, unconditionally and absolutely guaranteed, to the extent set forth in the Indenture and subject to the provisions in the Indenture, the due and punctual payment of the principal of, and premium, if any, and interest on the Securities and all other amounts due and payable under the Indenture and the Securities by the Company.

The obligations of the Parent Guarantor to the Holders of Securities and to the Trustee pursuant to its Guarantee and the Indenture are expressly set forth in Article XIV of the Indenture and reference is hereby made to the Indenture for the precise terms of the Guarantee.

ENTERPRISE PRODUCTS PARTNERS L.P.

By: Enterprise Products GP, LLC,
its General Partner

By: /s/ Richard H. Bachmann
Name: Richard H. Bachmann
Title: Executive Vice President

ABBREVIATIONS

The following abbreviations, when used in the inscription on the face of this instrument, shall be construed as though they were written out in full according to applicable laws or regulations:

TEN COM	- as tenants in common	UNIF GIFT MIN ACT —	____________ (Cust.)
TEN ENT	- as tenants by entireties	Custodian for:	____________ (Minor)
JT TEN	- as joint tenants with right of survivorship and not as tenants in common	under Uniform Gifts to Minors Act of	____________ (State)

Additional abbreviations may also be used though not in the above list.

ASSIGNMENT

FOR VALUE RECEIVED, the undersigned hereby sell(s), assign(s) and transfer(s) unto

PLEASE INSERT SOCIAL SECURITY OR OTHER
IDENTIFYING NUMBER OF ASSIGNEE

____

____

Please print or type name and address including postal zip code of assignee

____

____

the within Security and all rights thereunder, hereby irrevocably constituting and appointing

____

to transfer said Security on the books of the Company, with full power of substitution in the premises.

Dated ________________

____
Registered Holder

SCHEDULE OF INCREASES OR DECREASES IN GLOBAL SECURITY

The following increases or decreases in this Global Security have been made:

Date of Exchange	Amount of Decrease in Principal Amount of this Global Security	Amount of Increase in Principal Amount of this Global Security	Principal Amount of this Global Security following such decrease (or increase)	Signature of authorized officer of Trustee or Depositary

EXHIBIT 12.1

ENTERPRISE PRODUCTS PARTNERS L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in thousands)

	For the Year Ended December 31, 2004	2003	2002	2001	2000
Consolidated income	$268,261	$104,546	$ 95,500	$242,178	$220,506
Add: Minority interest	8,128	3,859	2,947	2,472	2,253
Provision for taxes	3,761	5,293	1,634		
Less: Equity in (income) loss of unconsolidated affiliates	(52,787)	13,960	(35,253)	(25,358)	(24,119)
Consolidated pre-tax income before minority interest and equity earnings from unconsolidated affiliates	227,363	127,658	64,828	219,292	198,640
Add: Fixed charges	168,463	151,338	111,141	63,172	42,706
Amortization of capitalized interest	974	579	363	217	167
Distributed income of equity investees	68,027	31,882	57,662	45,054	37,267
Subtotal	464,827	311,457	233,994	327,735	278,780
Less: Interest capitalized	(2,766)	(1,595)	(1,083)	(2,946)	(3,277)
Minority interest	(8,128)	(3,859)	(2,947)	(2,472)	(2,253)
Total earnings	$453,933	$306,003	$229,964	$322,317	$273,250
Fixed charges:					
Interest expense	$155,740	$140,806	$101,580	$ 52,456	$ 33,329
Capitalized interest	2,766	1,595	1,083	2,946	3,277
Interest portion of rental expense	9,957	8,937	8,478	7,770	6,100
Total	$168,463	$151,338	$111,141	$ 63,172	$ 42,706
Ratio of earnings to fixed charges	2.69x	2.02x	2.07x	5.10x	6.40x

These computations take into account our consolidated operations and the distributed income from our equity method investees. For purposes of these calculations, “earnings” is the amount resulting from adding and subtracting the following items:

Add the following, as applicable:

- consolidated pre-tax income before minority interest and income or loss from equity investees;
- fixed charges;
- amortization of capitalized interest;
- distributed income of equity investees; and
- our share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges.

From the subtotal of the added items, subtract the following, as applicable:

- interest capitalized;
- preference security dividend requirements of consolidated subsidiaries; and
- minority interest in pre-tax income of subsidiaries that have not incurred fixed charges.

The term “fixed charges” means the sum of the following: interest expensed and capitalized; amortized premiums, discounts and capitalized expenses related to indebtedness; an estimate of interest within rental expenses; and preference dividend requirements of consolidated subsidiaries.

EXHIBIT 21.1

LIST OF SUBSIDIARIES
Enterprise Products Partners L.P.
(Including Enterprise Products Operating L.P.)
as of March 1, 2005

Name of Subsidiary	Jurisdiction of Formation	Effective Ownership
Acadian Acquisition, LLC	Delaware	Acadian Gas, LLC – 100%
Acadian Consulting LLC	Delaware	Acadian Gas, LLC – 100%
Acadian Gas, LLC	Delaware	Enterprise Products Operating L.P. – 100%
Acadian Gas Pipeline System	Texas	TXO-Acadian Gas Pipeline, LLC – 50% MCN-Acadian Gas Pipeline, LLC – 50%
Arizona Gas Storage, L.L.C.	Delaware	Enterprise Arizona Gas, L.L.C. – 60%
Atlantis Offshore, LLC	Delaware	Manta Ray Gathering Company, L.L.C. – 50% Manta Ray Offshore Gathering Company, L.L.C. – 50%
Baton Rouge Fractionators LLC	Delaware	Enterprise Products Operating L.P. – 32.25% Third Parties – 67.75%
Baton Rouge Pipeline LLC	Delaware	Baton Rouge Fractionators LLC – 100%
Baton Rouge Propylene Concentrator, LLC	Delaware	Enterprise Products Operating L.P. – 30% Third Parties – 70%
Belle Rose NGL Pipeline, L.L.C.	Delaware	Enterprise NGL Pipelines, LLC 41.67% Third Parties – 58.33%
Belvieu Environmental Fuels GP, LLC	Delaware	Enterprise Products Operating L.P. – 100%
Belvieu Environmental Fuels L.P.	Texas	Enterprise Products Operating L.P. — 99% Belvieu Environmental Fuels GP, LLC – 1%
Cajun Pipeline Company, LLC	Texas	Enterprise Products Operating L.P. – 100%
Calcasieu Gas Gathering System	Texas	TXO-Acadian Gas Pipeline, LLC – 50% MCN-Acadian Gas Pipeline, LLC – 50%
Cameron Highway Oil Pipeline Company	Delaware	Cameron Highway Pipeline I, L.P. – 50% Third Party – 50%
Cameron Highway Pipeline GP, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Cameron Highway Pipeline I, L.P.	Delaware	Enterprise GTM Holdings L.P. – 99% Cameron Highway Pipeline GP, L.L.C. – 1%
Chunchula Pipeline Company, LLC	Texas	Enterprise Products Operating L.P. – 100%
Coyote Gas Treating Limited Liability Company	Delaware	Enterprise Field Services, L.L.C. – 50%
Crystal Holding, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Cypress Gas Marketing, LLC	Delaware	Acadian Gas, LLC – 100%
Cypress Gas Pipeline, LLC	Delaware	Acadian Gas, LLC – 100%
Deep Gulf Development, LLC	Delaware	Enterprise Offshore Development, LLC – 90% Third Party – 10%
Deepwater Gateway, L.L.C.	Delaware	Enterprise Field Services, L.L.C. – 50% Third Party — 50%
Dixie Pipeline Company	Delaware	Enterprise Products Operating L.P. – 38.1% Enterprise NGL Pipelines, LLC – 27.8% Third Parties – 34.0%
E-Cypress, LLC	Delaware	Enterprise Products Operating L.P. – 100%
E-Oaktree, LLC	Delaware	E-Cypress, LLC – 98% Third Party – 2%
Enterprise Alabama Intrastate, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise Arizona Gas, L.L.C.	Delaware	Enterprise Field Services, L.L.C. – 100%

Name of Subsidiary	Jurisdiction of Formation	Effective Ownership
Enterprise Energy Finance Corporation	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise Field Services, LLC	Delaware	Enterprise GTM Holdings L.P. — 100%
Enterprise Fractionation, LLC	Delaware	Enterprise Products Operating L.P. – 100%
Enterprise GC, L.P.	Delaware	Enterprise GTM Holdings L.P. – 99% Enterprise Holding III, L.L.C. – 1%
Enterprise GTMGP, LLC	Delaware	Enterprise Products GTM, LLC – 100%
Enterprise GTM Hattiesburg Storage, LLC	Delaware	Crystal Holding, L.L.C. – 100%
Enterprise GTM Holdings L.P.	Delaware	Enterprise Products Operating L.P. – 99% Enterprise GTMGP, LLC – 1%
Enterprise GTM Offshore Operating Company, LLC	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise Gas Liquids LLC	Delaware	Enterprise Products Operating L.P. – 100%
Enterprise Gas Processing LLC	Delaware	Enterprise Products Operating L.P. – 100%
Enterprise Holding III, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise Hydrocarbons L.P.	Delaware	Enterprise Products Texas Operating L.P. – 99% Enterprise Products Operating L.P. – 1%
Enterprise Intrastate L.P.	Delaware	Enterprise GTM Holdings L.P. – 99% Enterprise Holding III, L.L.C. – 1%
Enterprise Lou-Tex NGL Pipeline L.P.	Delaware	Enterprise Products Operating L.P. – 99% HSC Pipeline Partnership L.P. – 1%
Enterprise Lou-Tex Propylene Pipeline L.P.	Delaware	Enterprise Products Operating L.P. – 99% Propylene Pipeline Partnership L.P. – 1%
Enterprise NGL Marketing Company L.P.	Delaware	Enterprise Products Texas Operating L.P. – 99% Enterprise Products Operating L.P. – 1%
Enterprise NGL Pipelines, LLC	Delaware	Enterprise Products Operating L.P. – 100%
Enterprise Norco LLC	Delaware	Enterprise Products Operating L.P. – 100%
Enterprise Offshore Development, LLC	Delaware	Moray Pipeline Company, LLC – 100%
Enterprise Products GTM, LLC	Delaware	Enterprise Products Operating L.P. – 100%
Enterprise Products OLPGP, Inc.	Delaware	Enterprise Products Partners L.P. – 100%
Enterprise Products Operating L.P.	Delaware	Enterprise Products Partners L.P. – 99.999% Enterprise Products OLPGP, Inc. – 0.001%
Enterprise Products Texas Operating L.P.	Texas	Enterprise Products Operating L.P. – 99% Enterprise Products Partners L.P. – 1%
Enterprise Terminalling L.P.	Texas	Enterprise Products Operating L.P. – 99% Enterprise Gas Liquids LLC 1%
Enterprise Terminals & Storage, LLC	Delaware	Mapletree, LLC – 100%
Enterprise Texas Pipeline, L.P.	Delaware	Enterprise GTM Holdings L.P. – 99% Enterprise Holding III, L.L.C. – 1%
EPOLP 1999 Grantor Trust	Texas	Enterprise Products Operating L.P. – 100%
Evangeline Gas Corp.	Delaware	Evangeline Gulf Coast Gas, LLC – 45.05% Third Parties – 54.95%
Evangeline Gas Pipeline Company L.P.	Delaware	Evangeline Gulf Coast Gas, LLC – 45% Evangeline Gas Corp. – 10% Third Party – 45%
Evangeline Gulf Coast Gas, LLC	Delaware	Acadian Gas, LLC – 100%
First Reserve Gas, L.L.C.	Delaware	Crystal Holding, L.L.C. – 100%
Flextrend Development Company, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Grande Isle Pipeline LLC	Delaware	Enterprise Products Operating L.P. – 100%
Hattiesburg Gas Storage Company	Delaware	First Reserve Gas, L.L.C. – 50% Hattiesburg Industrial Gas Sales, L.L.C. – 50%
Hattiesburg Industrial Gas Sales, L.L.C.	Delaware	First Reserve Gas, L.L.C. – 100%
High Island Offshore System, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
HSC Pipeline Partnership, L.P.	Texas	Enterprise Products Operating L.P. – 99% Enterprise Products Partners L.P. – 1%

Name of Subsidiary	Jurisdiction of Formation	Effective Ownership
Independence Hub, LLC	Delaware	Enterprise Products Operating L.P. – 80% Third Party – 20%
K/D/S Promix, L.L.C.	Delaware	Enterprise Fractionation, LLC – 50% Third Parties – 50%
La Porte Pipeline Company L.P.	Texas	Enterprise Products Operating L.P. – 49.5% La Porte Pipeline GP, LLC – 1.0% Third Parties – 49.5%
La Porte Pipeline GP, L.L.C.	Texas	Enterprise Products Operating L.P. – 50% Third Parties – 50%
Mapletree, LLC	Delaware	Enterprise Products Operating L.P. – 98% Third Party – 2%
MCN Acadian Gas Pipeline, LLC	Delaware	Acadian Gas, LLC – 100%
MCN Pelican Interstate Gas, LLC	Delaware	Acadian Gas, LLC – 100%
MCN Pelican Transmission LLC	Delaware	Acadian Gas, LLC – 100%
Manta Ray Gathering Company, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Manta Ray Offshore Gathering Company, L.L.C.	Delaware	Neptune Pipeline Company, L.L.C. – 100%
Mid-America Pipeline Company, LLC	Delaware	Mapletree, LLC – 100%
Moray Pipeline Company, LLC	Delaware	Enterprise Products Operating L.P. – 100%
Nautilus Pipeline Company L.L.C.	Delaware	Neptune Pipeline Company, L.L.C. – 100%
Neches Pipeline System	Texas	TXO-Acadian Gas Pipeline, LLC – 50% MCN-Acadian Gas Pipeline, LLC – 50%
Nemo Gathering Company, LLC	Delaware	Enterprise NGL Pipelines, LLC – 33.92 Third Parties – 66.08%
Neptune Pipeline Company, L.L.C.	Delaware	Sailfish Pipeline Company, L.L.C. – 25.67% Third Parties – 74.33%
Norco-Taft Pipeline, LLC	Delaware	Enterprise NGL Private Lines & Storage, LLC – 100%
Olefins Terminal Corporation	Delaware	Enterprise Products Operating L.P. - 50% Third Party – 50%
Petal Gas Storage, L.L.C.	Delaware	Crystal Holding, L.L.C. – 100%
Pontchartrain Natural Gas System	Texas	TXO-Acadian Gas Pipeline, LLC – 50% MCN-Acadian Gas Pipeline, LLC – 50%
Port Neches GP, LLC	Delaware	Enterprise Products Operating L.P. – 100%
Port Neches Pipeline L.P.	Delaware	Enterprise Products Operating L.P. – 99% Port Neches GP, LLC — 1%
Poseidon Oil Pipeline Company, L.L.C.	Delaware	Poseidon Pipeline Company, L.L.C. – 36% Third Parties — 64%
Poseidon Pipeline Company, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Propylene Pipeline Partnership, L.P.	Texas	Enterprise Products Operating L.P. – 99% Enterprise Products Partners L.P. – 1%
Sabine Propylene Pipeline L.P.	Texas	Enterprise Products Operating L.P. – 99% Propylene Pipeline Partnership L.P. – 1%
Sailfish Pipeline Company, L.L.C.	Delaware	Enterprise Products Operating L.P. – 100%
Seminole Pipeline Company	Delaware	E-Oaktree, LLC – 80.0% E-Cypress, LLC – 10% Third Party – 10%
Sorrento Pipeline Company, LLC	Texas	Enterprise Products Operating L.P. – 100%
Starfish Pipeline Company, LLC	Delaware	Enterprise Products Operating L.P. – 50% Third Party – 50%
Stingray Pipeline Company, L.L.C.	Delaware	Starfish Pipeline Company, L.L.C. – 100%
Tejas-Magnolia Energy, LLC	Delaware	Pontchartrain Natural Gas System – 96.6% MCN-Pelican Interstate Gas, LLC – 3.4%
Teco Gas Processing, LLC	Delaware	Enterprise Products Operating L.P. – 100%

Name of Subsidiary	Jurisdiction of Formation	Effective Ownership
Teco Gas Gathering, LLC	Delaware	Enterprise Products Operating L.P. – 100%
Tri-States NGL Pipeline, L.L.C.	Delaware	Enterprise Products Operating L.P. – 33.3% Enterprise NGL Pipelines, LLC – 33.3% Third Parties – 33.3%
Triton Gathering, L.L.C.	Delaware	Starfish Pipeline Company, L.L.C. – 100%
TXO-Acadian Gas Pipeline, LLC	Delaware	Acadian Gas, LLC – 100%
Venice Energy Services Company, L.L.C.	Delaware	Enterprise Gas Processing LLC – 13.1% Third Parties – 86.99%
Venice Pipeline LLC	Delaware	Enterprise Products Operating L.P. – 100%
West Cameron Dehydration Company, L.L.C.	Delaware	Starfish Pipeline Company, L.L.C. – 100%
Wilprise Pipeline Company, LLC	Delaware	Enterprise Products Operating L.P. - 74.7% Third Parties — 25.3%

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in (i) Registration Statement No. 333-36856 of Enterprise Products Partners L.P. on Form S-8; (ii) Registration Statement No. 333-102778 of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. on Form S-3; (iii) Registration Statement No. 333-82486 of Enterprise Products Partners L.P. on Form S-8; (iv) Registration Statement No. 333-107073 of Enterprise Products Partners L.P. on Form S-3; (v) Registration Statement No. 333-114758 of Enterprise Products Partners L.P. on Form S-3; (vi) Registration Statement No. 333-115633 of Enterprise Products Partners L.P. on Form S-8; and (vii) Registration Statement No. 333-115634 of Enterprise Products Partners L.P. on Form S-8; (viii) Registration Statement No. 333-121665 of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. on Form S-4; (ix) Registration Statement No. 333-123150 of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. on Form S-3; of our reports dated March 15, 2005, relating to the financial statements and financial statement schedule of Enterprise Products Partners L.P. and to management's report on the effectiveness of internal control over financial reporting, appearing in the Annual Report on Form 10-K of Enterprise Products Partners L.P. for the year ended December 31, 2004.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 15, 2005

EXHIBIT 31.1

CERTIFICATIONS

I, Robert G. Phillips, certify that:

1. I have reviewed this annual report on Form 10-K of Enterprise Products Partners L.P.;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2005

/s/ Robert G. Phillips

Name: Robert G. Phillips
Title: Principal Executive Officer of our General Partner, Enterprise Products GP, LLC

EXHIBIT 31.2

CERTIFICATIONS

I, Michael A. Creel, certify that:

1. I have reviewed this annual report on Form 10-K of Enterprise Products Partners L.P.;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2005

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Principal Financial Officer of our General Partner, Enterprise Products GP, LLC

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF ROBERT G. PHILLIPS, CHIEF EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this annual report of Enterprise Products Partners L.P. (the “Registrant”) on Form 10-K for year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert G. Phillips, Chief Executive Officer of Enterprise Products GP, LLC, the general partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Robert G. Phillips

Name: Robert G. Phillips
Title: Chief Executive Officer of Enterprise Products GP, LLC
on behalf of Enterprise Products Partners L.P.

Date: March 15, 2005

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF MICHAEL A. CREEL, CHIEF FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this annual report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-K for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Financial Officer of Enterprise Products GP, LLC, the general partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Chief Financial Officer of Enterprise Products GP, LLC
on behalf of Enterprise Products Partners L.P.

Date: March 15, 2005