ENTERPRISE PRODUCTS PARTNERS L P
Form 8-K
December 06, 2004

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

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): September 30, 2004

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of registrant as specified in its charter)

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

2727 North Loop West, Houston, Texas	**77008-1044**
(Address of Principal Executive Offices)	(Zip Code)

Registrant s Telephone Number, including Area Code: **(713) 880-6500**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

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

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

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

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

Item 8.01. Other Events.

As described in our quarterly report on Form 10-Q for the period ended September 30, 2004 (the September 30, 2004 10-Q), Enterprise Products Partners L.P. (Enterprise) and GulfTerra Energy Partners, L.P. (GulfTerra) completed the merger of GulfTerra with a wholly-owned subsidiary of Enterprise. As a result of the merger, and as described in our September 30, 2004 10-Q, we have revised and renamed our reportable business segments to reflect the combined operations of the two companies. As an aid in comparability and for transition purposes, we are hereby updating portions of the historical description of our business and segment-related information as set forth in our annual report on Form 10-K for the year ended December 31, 2003 originally found under Items 1 and 2 (Business and Properties) and Item 7 (Management s Discussion and Analysis of Financial Condition and Results of Operation or MD&A) and Item 7A (Quantitative and Qualitative Disclosures About Market Risk). In addition, we are hereby updating our audited consolidated financial statements included under Item 8 (Financial Statements and Supplementary Data) to solely reflect the new business segments.

Please refer to our annual report on Form 10-K for the year ended December 31, 2003 for the definitions of capitalized terms not defined herein. We have presented the following sections of our 2003 annual report on Form 10-K solely to reflect our new business segment information as if our new business segment reporting structure had been in place on December 31, 2003. Except as required to reflect the effects of our new business segment information, these items have not been modified or updated for events subsequent to the filing of our annual report on Form 10-K for the year ended December 31, 2003. The following represents an index to the various sections of the material presented under Item 8.01 of this current report on Form 8-K:

In addition to presenting the foregoing information, we are including a supplemental schedule containing selected quarterly financial and operating information stated as if our new business segment reporting structure had been in place during 2003 and for the nine months ended September 30, 2004.

SECTION 1 REVISED BUSINESS DESCRIPTION
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 and natural gas liquids, or NGLs. We were formed as a limited partnership in 1998 (NYSE symbol, EPD) and conduct all of our business through our wholly-owned subsidiary, Enterprise Products Operating L.P. and its subsidiaries and joint ventures. Our General Partner, Enterprise Products GP, LLC, owns a 2% interest in us.

We do not have any employees. All of our management, administrative and operating functions are performed by employees of EPCO, our ultimate parent company, 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 t mean the consolidated business and operations of Enterprise Products Partners L.P. Our principal executive offices are located at 2727 North Loop West, Houston, Texas 77008 and our telephone number is (713) 880-6500.

We provide a full range of services to customers and generate predominately fee-based net cash flow from multiple sources along our natural gas and NGL system of assets. NGLs 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 and industrial fuels. Our midstream energy services include the:

- gathering and transmission of raw natural gas from both onshore and offshore Gulf of Mexico developments;
- processing of raw natural gas into a marketable product that meets industry quality specifications by removing mixed NGLs and impurities;
- purchase of natural gas for resale to our industrial, utility and municipal customers;
- transportation of mixed NGLs to fractionation facilities by pipeline;
- fractionation (or separation) of mixed NGLs produced as by-products of crude oil refining and natural gas production into component NGL products: ethane, propane, isobutane, normal butane and natural gasoline;
- transportation of NGL products to end-users by pipeline, railcar and truck;
- import and export of NGL products and petrochemical products through our dock facilities;
- fractionation of refinery-sourced propane/propylene mix into high-purity propylene, propane and mixed butane;
- transportation of high-purity propylene to end-users by pipeline;
- storage of natural gas, mixed NGLs, NGL products and petrochemical products;
- conversion of normal butane to isobutane through the process of isomerization;
- production of high-octane additives for motor gasoline from isobutane; and
- sale of NGLs and petrochemical products we produce and/or purchase for resale.

In addition to our strategic position in the Gulf of Mexico, we have access to major natural gas and NGL supply basins throughout the United States and Canada, including the Rocky Mountains, the San Juan and Permian basins, the Mid-Continent region and, through third-party pipeline connections, north into Canada s Western Sedimentary basin. Our asset platform in the Gulf Coast region of the United States, combined with our Mid-America and Seminole pipeline systems, create the only integrated natural gas and NGL transportation, fractionation, processing, storage and import/export network in North America.

Business Strategy

Our business strategy is to:

- capitalize on expected increases in natural gas and NGL production resulting from development activities in the Rocky Mountain, Permian Basin and Mid-Continent regions and the deepwater regions, continental shelf and onshore and coastal areas of the Gulf of Mexico;
- develop and invest in joint venture projects with strategic partners that will either provide the raw materials for these projects or purchase the ventures end products;
- share capital costs and risks associated with our operations through the formation of strategic alliances, joint ventures and similar arrangements with other businesses;
- expand our asset base through accretive acquisitions of complementary midstream energy assets, particularly those of fee-based businesses such as pipelines; and
- maintain a sound capital structure, which is important in managing our liquidity and capital resource requirements and providing us with the financial flexibility to fund future growth opportunities.

Recent Events

On December 15, 2003, we and certain of our affiliates, El Paso Corporation and certain of its affiliates (El Paso), and GulfTerra Energy Partners, L.P. (GulfTerra) and certain of its affiliates entered into a series of agreements under which GulfTerra would merge with one of our subsidiaries, with GulfTerra surviving the merger and becoming a wholly-owned subsidiary of the Company. Formed in 1993, GulfTerra is a publicly traded limited partnership (NYSE symbol, GTM) that manages a balanced, diversified portfolio of interests and assets relating to the midstream energy sector. Prior to December 15, 2003, El Paso was the majority owner of GulfTerra s general partner and owns a 31.8% limited partner interest in GulfTerra. GulfTerra s principal executive offices are located at 4 East Greenway Plaza, Houston, Texas 77046 and its phone number is (832) 676-4853.

In general, GulfTerra s business lines include:

- Ownership or interests in over 15,700 miles of natural gas pipeline systems. These pipeline systems include gathering systems onshore in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas and offshore in some of the most active drilling and development regions in the Gulf of Mexico. GulfTerra also owns interests in five natural gas processing and treating plants located in New Mexico, Texas and Colorado;
- Ownership in over 1,000 miles of intrastate NGL gathering and transportation pipelines and four NGL fractionation plants located in Texas. GulfTerra also owns interests in three offshore oil pipeline systems, which extend over 340 miles, owns a 3.3 MMBbl propane storage and leaching business located in Mississippi and owns or leases NGL storage facilities in Louisiana and Texas with aggregate capacity of approximately 21.3 MMBbls;
- Ownership in two salt dome natural gas storage facilities located in Mississippi that have a combined current working capacity of 13.5 Bcf. In addition, GulfTerra has the exclusive right to use a natural gas storage facility located in Wharton, Texas under an operating lease that expires in January 2008. This facility has a working gas capacity of 6.4 Bcf;
- Interests in seven multi-purpose offshore hub platforms in the Gulf of Mexico that were specifically designed to be used as deepwater hubs and production handling and pipeline maintenance facilities; and
- Interests in four oil and natural gas producing properties located in waters offshore Louisiana. Production is gathered, transported, and processed through GulfTerra s pipeline systems and platform facilities, and sold to various third parties and El Paso.

GulfTerra is one of the largest natural gas gatherers, based on miles of pipeline, in the prolific natural gas supply regions offshore in the Gulf of Mexico and onshore in Texas and in the San Juan Basin, which covers a significant portion of the four contiguous corners of Arizona, Colorado, New Mexico and Utah. These regions, especially the deepwater regions of the Gulf of Mexico, one of the United States fastest growing oil and natural gas producing regions, offer GulfTerra significant growth potential through the acquisition and construction of pipelines, platforms, processing and storage facilities and other energy infrastructure.

The proposed merger is a three-step process outlined as follows:

Step One. On December 15, 2003, we purchased a 50% membership interest in GulfTerra s general partner (GulfTerra Energy Company, L.L.C. or GulfTerra GP) for $425 million. This investment is accounted for using the equity method. This transaction is referred to as Step One of the proposed merger and will remain in effect even if the remainder of the proposed merger and post-merger transactions, which we refer to as Step Two and Step Three, do not occur.

Step Two. If all necessary regulatory and unitholder approvals are received and the other merger agreement conditions are either fulfilled or waived and the following steps are consummated, we will own 100% of the limited and general partner interests in GulfTerra. At that time, the proposed merger will be accounted for using the purchase method and GulfTerra will be a consolidated subsidiary of our company. Step Two of the proposed merger includes the following transactions:

El Paso s contribution to our General Partner of El Paso s remaining 50% interest in GulfTerra GP for a 50% interest in our General Partner, and the subsequent capital contribution by our General Partner of such 50% interest in GulfTerra GP to us (without increasing our General Partner s interest in our earnings or cash distributions).

Our purchase of 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units owned by El Paso for $500 million; and

The exchange of each remaining GulfTerra common unit for 1.81 Enterprise common units, resulting in the issuance of approximately 103 million Enterprise common units to GulfTerra unitholders.

Step Three. Immediately after Step Two is completed, we expect to acquire nine cryogenic natural gas processing plants, one natural gas gathering system, one natural gas treating plant, and a small natural gas liquids connecting pipeline from El Paso for $150 million. We refer to the assets that we will acquire from El Paso as the South Texas midstream assets.

Our preliminary estimate of the total consideration for Steps One, Two and Three we would pay or grant is approximately $3.9 billion. For a period of three years following the closing of the proposed merger, El Paso will provide support services to GulfTerra similar to those provided by El Paso prior to the closing of the merger. GulfTerra will reimburse El Paso for 110% of its direct costs of such services (excluding any overhead costs). El Paso will make transition support payments to us in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in 12 equal monthly installments for each such year. These transition support payments are included in our preliminary estimate of total consideration.

We are working to complete the merger as soon as possible. A number of conditions must be satisfied before we can complete the merger, including approval by the unitholders of both the Company and GulfTerra and the expiration or termination of applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1974. While we cannot predict if and when all of the conditions to the merger will be satisfied, we expect to complete the merger in the second half of 2004.

To review a copy of the merger agreement and related transaction documents, please read our Current Report on Form 8-K filed with the Securities and Exchange Commission on December 15, 2003.

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 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 o future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our General Partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. 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 our summarized *Risk Factors* below.

Risk Factors

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

Risks Related to the Merger and the Related Transactions

We may not be able to successfully integrate our operations with GulfTerra s operations.

Integration of the two previously independent companies will be a complex, time consuming and costly process. Failure to timely and successfully integrate these companies may have a material adverse effect on the combined company s business, financial condition and results of operations. The difficulties of combining the companies will present challenges to the combined company s management, including:

- operating a significantly larger combined company with operations in geographic areas and business lines in which we have not previously operated;
- managing relationships with new joint venture partners with whom we have not previously partnered;
- integrating personnel with diverse backgrounds and organizational cultures;
- experiencing potential operational interruptions or the loss of key employees, customers or suppliers;
- establishing the internal controls and procedures that the combined company will be required to maintain under the Sarbanes-Oxley Act of 2002; and
- consolidating other corporate and administrative functions.

The combined company will also be exposed to other risks that are commonly associated with transactions similar to the merger, such as unanticipated liabilities and costs, some of which may be material, and diversion of management s attention. As a result, the anticipated benefits of the merger may not be realized fully, if at all. We and GulfTerra could be required to divest significant assets to complete the merger.

We and GulfTerra could be required to divest significant assets by regulatory authorities to complete the merger

We cannot complete the merger until the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 has expired or terminated. Under the terms of the merger agreement, we are required to divest the assets we previously acquired from GulfTerra that are subject to an FTC consent decree (including our interests in the Manta Ray, Nautilus, Nemo and Stingray pipelines). GulfTerra is required to divest any assets required by the FTC to the extent such divestitures are recommended by us and we are required to divest any assets required by the FTC to the extent such divestitures, together with all required GulfTerra divestitures (but excluding the FTC consent decree assets), do not exceed $150 million. In addition, if such divestitures required by the FTC exceed $150 million, we and (with our consent) GulfTerra have the right to comply with such divestiture requirements to consummate the merger.

Divestitures of assets can be time consuming and may delay completion of the proposed merger. Because there may be a limited number of potential buyers for the assets subject to divestiture and because potential buyers will likely be aware of the circumstances of the sale, these assets could be sold at prices lower than their fair market value or the prices we or GulfTerra paid for these assets. These asset divestitures could also significantly reduce the value of the combined company, eliminate potential cost savings opportunities or lessen the anticipated benefits of the merger.

Risks Related to the Combined Company s Leverage

The combined company s debt level may limit its future financial and operating flexibility.

As of December 31, 2003, we had approximately $2.1 billion of consolidated debt. As of the same date, GulfTerra had approximately $1.8 billion of consolidated debt. As a result, the consolidated balance sheet of the combined company will have significant leverage. The amount of the combined company s debt could have several important effects on its future operations, including, among other things:

- a significant portion of the combined company s 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;
- the combined company s ability to pay distributions could be adversely affected;
- credit rating agencies may view the combined company s debt level negatively;
- covenants contained in our and GulfTerra s existing debt arrangements will require the combined company to continue to meet financial tests that may affect its flexibility in planning for and reacting to changes in its business;
- the combined company s ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;
- the combined company may be at a competitive disadvantage relative to similar companies that have less debt; and
- the combined company may be more vulnerable to adverse economic and industry conditions as a result of its 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 revolving credit facilities and the merger agreement, however, restrict our ability to incur additional debt, though any debt we may incur in compliance with these restrictions may still be substantial. Likewise, GulfTerra s public debt indentures, its revolving credit facility and the merger agreement restrict its ability to incur additional debt; however, any debt that it may incur in compliance with these restrictions may still be substantial. The incurrence of additional debt by GulfTerra or us could exacerbate any risks associated with the liquidity of the combined company.

Our and GulfTerra s revolving credit facilities and indentures for public debt contain conventional financial covenants and other restrictions. A breach of any of these restrictions by us or GulfTerra, as applicable, 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.

The combined company s ability to access the capital markets to raise capital on favorable terms may be affected by the combined company s debt level, the amount of its 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. If the combined company is unable to access the capital markets on favorable terms in the future, it might be forced to seek extensions for some of its short-term securities or to refinance some of its debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which the combined company 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 the combined company s leverage may adversely affect its future financial and operating flexibility and its ability to pay cash distributions at expected rates.

The closing of the merger will trigger a repurchase obligation with respect to GulfTerra s outstanding senior notes and senior subordinated notes.

The closing of the merger will constitute a change of control under GulfTerra s indentures for its senior notes and senior subordinated notes. As a result, GulfTerra will be obligated to offer to purchase each holder s notes at 101% of their principal amount, plus accrued interest. GulfTerra will also be obligated to offer to purchase each holder s senior notes at 101% of their principal amount, plus accrued interest, unless, among other things, the change of control (1) does not result in a ratings downgrade of the GulfTerra senior notes by either Moody s Investors Service or Standard & Poor s no later than 30 days after the change of control has occurred and (2) less than $250 million in aggregate principal amount of the GulfTerra senior subordinated notes are repurchased in response to the same change of control. GulfTerra currently has $250 million aggregate principal amount of senior notes outstanding and $886 million aggregate principal amount of senior subordinated notes outstanding.

In connection with completion of the merger, GulfTerra or the combined company will need to make an offer to repurchase these notes, or GulfTerra may seek to amend the indentures to waive the repurchase obligation or otherwise refinance its senior and senior subordinated notes. If GulfTerra or the combined company makes an offer to repurchase the notes, it is possible that holders of a large amount of GulfTerra s notes may exercise their repurchase right, in which case the combined company would be required to raise significant funds in the short term to fulfill GulfTerra s repurchase obligations. If GulfTerra were unable to meet its repurchase obligations, it would result in an event of default under GulfTerra s indentures, which would trigger an event of default under GulfTerra s revolving credit facility and senior secured term loan facility.

Increases in interest rates could adversely affect the combined company s business.

In addition to the combined company s exposure to commodity prices, the combined company will have significant exposure to increases in interest rates. As of December 31, 2003, we had approximately $2.1 billion of consolidated debt, of which $1.7 billion was at a fixed interest rate and $410 million was at a variable interest rate. Since January 1, 2004, we have entered into interest rate swap transactions that have effectively converted $250 million of our variable interest rate debt to fixed interest rate debt. For additional information regarding our interest rate hedging activities, please read Item 7A of this annual report on Form 10-K. Our merger with GulfTerra will result in a significant increase in our consolidated debt, some of which will be at variable interest rates. As a result, the combined company s results of operations, and its cash flows, could be materially adversely affected by significant increases in interest rates.

Risks Related to the Combined Company s Business

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

The combined company will operate predominantly in the midstream energy sector, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs and crude oil. As such, the combined company s results of operations, cash flows and financial position may be 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.

The profitability of the combined company s NGL and natural gas processing operations will depend upon the difference between NGL product prices and natural gas prices. A reduction in the difference between NGL product prices and natural gas prices may result in reduced demand for fractionation, processing, NGL storage and NGL transportation services and, thus, may adversely affect the combined company s results of operations and cash flows from these activities. In addition, the combined company s natural gas processing activities will be exposed to commodity price risk associated with the relative price of NGLs to natural gas under its keepwhole natural gas processing contracts and, within defined limits, under its margin-band natural gas processing contract with Shell. Under these types of agreements, the combined company will take title to NGLs that it extracts from the natural gas stream and will be obligated to pay market value, based on natural gas prices, for the energy extracted from the natural gas stream. When prices for natural gas increase, the cost to the combined company of making these keepwhole payments will increase, and, where NGL prices do not experience a commensurate increase, the combined company will realize lower margins from these transactions. As a result, changes in prices for natural gas compared to NGLs could have an adverse affect on the results of operations, cash flows and financial position of the combined company.

The combined company will also be exposed to natural gas and NGL commodity price risk under natural gas processing and gathering and NGL fractionation contracts that provide for the combined company s 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. For example, over 95% of the volumes handled by GulfTerra s San Juan gathering system are fee-based arrangements, 80% of which are calculated as a percentage of a regional natural gas price index. A decrease in natural gas and NGL prices can result in lower margins from these activities, which may adversely affect the combined company s results of operations, cash flows and financial position.

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

The combined company s profitability could be materially impacted by a decline in the volume of natural gas, NGLs and crude oil transported, gathered or processed at its 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 the exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and crude oil handled by the combined company s facilities.

The crude oil, natural gas and NGLs available to the combined company s facilities will be derived from reserves produced from existing wells, which reserves naturally decline over time. To offset this natural decline, the combined company s facilities will need access to additional reserves. Additionally, some of the combined company s 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 the combined company s 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 the combined company s facilities are located. This could result in a decrease in volumes to the combined company s offshore platforms, natural gas processing plants, natural gas, crude oil and NGL pipelines, and NGL fractionators which would have an adverse affect on the combined company s results from 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 adversely affect the combined company s 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 adversely affect the combined company s results of operations, cash flows and financial position. For example:

Ethane. A reduction in the demand for ethylene may reduce demand for ethane. Also, 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, the combined company s 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 the combined company produces and expose the combined company s 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.

The combined company will face competition from third parties in its midstream businesses.

Even if reserves exist in the areas accessed by the combined company s facilities and are ultimately produced, the combined company may not be chosen by the producers in these areas to gather, transport, process, fractionate, store or otherwise handle the hydrocarbons that are produced. The combined company will 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.

The combined company s growth strategy may adversely affect its results of operations if it does not successfully integrate the businesses that it acquires or if the combined company substantially increases its indebtedness and contingent liabilities to make acquisitions.

The combined company s ability to successfully execute its growth strategy is partially dependent upon making accretive acquisitions. As a result, from time to time, the combined company may evaluate and acquire assets and businesses that it believes complement its existing operations. Similar to the risks associated with integrating our operations with GulfTerra s operations, the combined company may be unable to integrate successfully businesses it acquires in the future. The combined company may incur substantial expenses or encounter delays or other problems in connection with its growth strategy that could negatively impact its results of operations. 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;
- 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, the combined company s capitalization and results of operations may change significantly following an acquisition. A substantial increase in the combined company s indebtedness and contingent liabilities could have a material adverse effect on its business.

The combined company s capital projects may not result in an immediate increase in operating cash flows.

GulfTerra is engaged in several capital expansion projects and greenfield projects for which significant capital has been expended, and the combined company s operating cash flow from a particular project may not increase immediately following its completion. For instance, if the combined company builds a new pipeline or platform or expands an existing facility, the design, construction, development and installation may occur over an extended period of time and the combined company may not receive any material increase in operating cash flow from that project until after it is placed in service. If the combined company experiences unanticipated or extended delays in generating operating cash flow from these projects, then it may need to reduce or reprioritize its capital budget, sell non-core assets, access the capital markets or decrease distributions to unitholders to meet its capital requirements.

The combined company s actual construction, development and acquisition costs could exceed forecasted amounts.

The combined company may 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 costly and involve much more uncertainty and risk, and if a problem occurs, the solution, if one exists, may be very costly and time consuming. Accordingly, there is an increase in the frequency and amount of cost overruns related to underwater operations, especially in depths in excess of 600 feet. The combined company may not be able to complete its projects, whether in deep water or otherwise, at the costs currently estimated.

The combined company may not be able to fully execute its growth strategy if it encounters illiquid capital markets or increased competition for qualified assets.

The strategy of the combined company includes 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 the combined company s ability to compete effectively and diversify its asset portfolio, thereby providing more stable cash flow. Both companies regularly consider and enter into discussions regarding, and are currently contemplating, potential joint ventures, stand-alone projects or other transactions that they believe will present opportunities to realize synergies, expand their respective roles in the energy infrastructure business and increase their respective market positions.

The combined company may need new capital to finance the future development and acquisition of assets and businesses. Limitations on the combined company s access to capital may impair its ability to execute this strategy. Costly capital may limit the combined company s ability to develop or acquire accretive assets. This strategy may require substantial capital, and the combined company may not be able to raise the necessary funds on satisfactory terms, if at all.

In addition, both companies are experiencing increased competition for the assets they purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in the combined company not being the successful bidder more often or the combined company s acquiring assets at a higher relative price than that which they have paid historically. Either occurrence would limit the combined company s ability to fully execute its growth strategy. The combined company s ability to execute its growth strategy may impact the market price of its securities.

An impairment of goodwill could reduce the combined company s earnings.

We have recorded $82.4 million of goodwill on our consolidated balance sheet as of December 31, 2003. Based upon our preliminary analysis, we anticipate recording approximately $2 billion of goodwill upon completion of the merger, but that estimate is subject to change. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Generally accepted accounting principles will require the combined company to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. If the combined company were to determine that any of its remaining balance of goodwill was impaired, it would be required to take an immediate charge to earnings with a correlative effect on unitholders equity.

The use of derivative financial instruments could result in financial losses to the combined company.

We and GulfTerra 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 the combined company hedges its commodity price and interest rate exposures, it will forego the benefits it would otherwise experience if commodity prices or interest rates were to change in its 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.

The combined company will be unable to cause its joint ventures to take or not to take certain actions unless some or all of its joint venture participants agree.

We and GulfTerra participate in several substantial joint ventures, and that participation will continue after the merger. Due to the nature of 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, the combined company may be unable to cause any of its joint ventures to take or not to take certain actions, even though those actions may be in the best interest of the particular joint venture or the combined company.

In addition, each joint venture s charter documents typically vest in its management committee sole discretion regarding the occurrence and amount of distributions. Some of the joint ventures in which the combined company will participate have separate credit arrangements that contain various restrictive covenants. Among other things, those covenants may limit or restrict the joint venture s ability to make distributions to the combined company under certain circumstances. Accordingly, the combined company s joint ventures may, following the merger, be unable to make distributions to the combined company at current levels or at all.

Moreover, the combined company cannot be certain that any of the joint venture owners will not sell, transfer or otherwise modify their ownership interest in a joint venture, whether in a transaction involving third parties and/or the other joint venture owners. Any such transaction could result in the combined company partnering with different or additional parties.

The interruption of distributions to the combined company from its subsidiaries and joint ventures may affect the combined company s ability to satisfy its obligations and to make cash distributions to its unitholders.

Like us and GulfTerra, the combined company will be a holding company with no business operations. The only significant asset of the combined company will be the equity interests it owns in its subsidiaries and joint ventures. As a result, the combined company will depend upon the earnings and cash flow of its subsidiaries and joint ventures and the distribution of that cash to the combined company in order to meet the combined company s obligations and to allow it to make distributions to its unitholders.

GulfTerra is party to senior and senior subordinated note indentures under which approximately $1.1 billion in principal amount of debt securities was outstanding as of December 31, 2003. These indentures restrict

GulfTerra s and its subsidiaries ability to make cash distributions. If GulfTerra and the combined company are not able to effect amendments to these indentures or refinance the senior and senior subordinated notes, then these restrictions could significantly limit GulfTerra s ability to distribute cash to us after the merger.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail the combined company s operations and otherwise adversely affect its cash flow.

Some of the combined company s operations will involve risks of personal injury, property damage and environmental damage, which could curtail the combined company s operations and otherwise adversely affect its cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. The combined company also will 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 the combined company s operations will be exposed to the elements, including hurricanes, tornadoes, storms, floods and earthquakes.

If one or more facilities that are owned by the combined company or that deliver oil, natural gas or other products to the combined company are damaged by severe weather or any other disaster, accident, catastrophe or event, the combined company s operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply the combined company s facilities or other stoppages arising from factors beyond its 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 the combined company will be a party to will obligate it to indemnify its customers for any damage or injury occurring during the period in which the customers natural gas is in its possession. Any event that interrupts the fees generated by the combined company s energy infrastructure assets, or which causes it to make significant expenditures not covered by insurance, could reduce the combined company s cash available for paying its interest obligations as well as unitholder distributions and, accordingly, adversely affect the market price of the combined company s securities.

We expect that the combined company will maintain adequate insurance coverages, although it 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, the combined company may not be able to renew its existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. In particular, we have been informed by our insurance carrier that upon renewal of our policy in April 2004, MTBE related claims may be excluded from the scope of our insurance coverage. See *Regulation and Environmental Matters Impact of Clean Air Act s oxygenated fuels programs on our BEF investment*, beginning on page 42 of this annual report. If the combined company were to incur a significant liability for which it was not fully insured, it could have a material adverse effect on the combined company s financial position. 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.

Terrorist attacks aimed at the combined company s facilities could adversely affect its 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 the combined company s facilities, those of its customers and, in some cases, those of other pipelines, could have a material adverse effect on the combined company s 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 the combined company s 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 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 its general partner.

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 our general partner. 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 our general partner, in its 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, working capital borrowings and, after the merger, distributions from GulfTerra and its unconsolidated affiliates, and not solely on profitability, which is affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

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 due our general partner may be substantial and will reduce our cash available for distribution to holders of our units.

Prior to making any distribution on our units, we will reimburse our general partner and its affiliates, including officers and directors of our general partner, 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. Our general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide other services to us for which we will be charged fees as determined by our general partner.

Our general partner and its affiliates have limited fiduciary responsibilities and conflicts of interest with respect to our partnership.

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

- decisions of our general partner 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 the general partner;
- under our partnership agreement, our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our general partner is allowed to take into account the interests of parties other than us, such as our parent company, EPCO, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to unitholders;
- affiliates of our general partner may compete with us in certain circumstances;
- our general partner 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 our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Unitholders did not elect our general partner 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 our general partner. Our general partner may not be removed except upon the vote of the holders of at least 66.7% of our outstanding units voting together as a single class. Because affiliates of our general partner own more than one-third of our outstanding units, our general partner currently cannot be removed without the consent of our general partner and its affiliates.

Unitholders voting rights are further restricted by our partnership agreement provision stating that any units held by a person that owns 20% or more of any class of 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 price at which our common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

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 the obligations of our partnership, such as our debts and environmental liabilities, except for those contractual obligations of our partnership 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. Immediately after the merger occurs, we currently estimate a total of approximately 320 million of our common units (including those which may be issued upon unitholder approval and the conversion of the 4,413,549 of our Class B special units) will be outstanding. Shell owns 41,000,000 of our common units, representing approximately 19.1% of our outstanding common units at February 20, 2004, 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 its common units in the future.

Tax Risks Related to the Merger and to Owning Our Common Units

No ruling has been obtained with respect to the tax consequences of the merger.

While it is anticipated that no gain or loss will be recognized by our unitholders as a result of the merger (except with respect to a net decrease in a unitholder s share of nonrecourse liabilities discussed below), no ruling has been or will be requested from the Internal Revenue Service, or IRS, with respect to the tax consequences of the merger. Instead, we are relying on the opinions of our counsel as to the tax consequences of the merger, and counsel s conclusions may not be sustained if challenged by the IRS.

The merger may result in income recognition by our unitholders.

As a result of the merger, our common unitholder s share of nonrecourse liabilities will be recalculated. Each of our unitholders will be treated as receiving a deemed cash distribution equal to the excess, if any, of such unitholder s share of nonrecourse liabilities immediately before the merger and such unitholder s share of nonrecourse liabilities immediately following the merger. If the amount of the deemed cash distribution received by a common unitholder exceeds the unitholder s basis in its partnership interest, such unitholder will recognize gain in an amount equal to such excess. The application of the rules governing the allocation of nonrecourse liabilities in the context of the merger is complex and subject to uncertainty. While we have agreed to apply these rules, to the extent permissible, in a manner that minimizes the amount of any net decrease in the amount of debt allocable to our unitholders, there can be no assurance that there will not be a net decrease in the amount of nonrecourse liabilities allocable to our common unitholder as a result of the merger.

The IRS could treat us as a corporation for tax purposes, which would substantially reduce the cash available for distribution to common unitholders following the merger.

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

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

A change in current law or a change in our business could cause us to be taxed as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution and the target distribution levels will be decreased to reflect that impact on us.

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

We have not requested a ruling from the IRS with respect to any matter affecting our partnership. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or the positions we take. A court may not concur with our counsel s conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will be borne indirectly by our unitholders and our general partner.

Our common unitholders may be required to pay taxes even if they do not receive any cash distributions.

Our common unitholders are required to pay federal income taxes and, in some cases, state, local and foreign income taxes on their share of our taxable income even if they do not receive any cash distributions from us. They may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

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

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

Tax-exempt entities, regulated investment companies and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Ownership of common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), regulated investment companies (known as mutual funds) and foreign persons raises issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Very little of our income will be qualifying income to a regulated investment company or mutual fund. Distributions to foreign persons will be reduced by withholding taxes at the highest effective U.S. federal income tax rate for individuals, and foreign persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

We are registered as a tax shelter, which may increase the risk of an IRS audit of us or a unitholder.

We are registered with the IRS as a tax shelter. Our tax shelter registration number is 990610007. The tax laws require that some types of entities, including some partnerships, register as tax shelters in response to the perception that they claim tax benefits that may be unwarranted. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a 1% profits interest in us has very limited rights to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in our unitholders tax returns and may lead to audits of our unitholders tax returns and adjustments of items unrelated to us. You will bear the cost of any expense incurred in connection with an examination of your personal tax return and indirectly bear a portion of the cost of an audit of us.

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

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

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

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property and in which they do not reside. Our common unitholders may be required to file state and local income tax returns and pay state and local income taxes in many or all of the jurisdictions in which we do business or own property. Further, our common unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of the unitholder to file all United States federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of ownership of our common units.

The Company s Operations

As a result of our merger with GulfTerra, we have four reportable segments: Offshore Pipelines & Services, Onshore Natural Gas Pipelines & Services, NGL Pipelines & Services, and Petrochemical Services. Our new 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.

Offshore Pipelines & Services

At December 31, 2003, our Offshore Pipelines & Services business segment consisted of equity interests in companies that own 739 miles of natural gas pipelines located offshore Louisiana in the Gulf of Mexico.

Our offshore natural gas pipeline systems provide for the gathering and transmission of natural gas from offshore Louisiana natural gas production developments. Typically, these systems receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas at other points throughout the system. Generally, natural gas pipeline transportation agreements generate revenue for these systems based on a transportation fee per unit of volume (generally in MMBtus) transported. In general, the Gulf of Mexico systems in which we own an equity interest do not take title to the natural gas volumes that they transport; rather, the shipper retains title and the associated commodity price risk.

Our Gulf of Mexico offshore pipelines compete with other offshore systems primarily on the basis of transportation rates and service and are strategically situated to gather a substantial volume of natural gas production in the offshore Louisiana area from both continental shelf and deepwater developments. 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 systems are 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 oil and gas fields 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 fields.

The following table summarizes our offshore natural gas pipeline transportation and distribution networks at December 31, 2003. Our ownership interest in each pipeline is held indirectly through a company in which we have an investment accounted for under the equity method.

Offshore Natural Gas Pipelines	Length in Miles	Our Ownership Interest at December 31, 2003
Stingray	379	50.0%
Manta Ray	235	25.7%
Nautilus	101	25.7%
Nemo	24	33.9%
Total offshore natural gas pipelines	739	

Stingray. The Stingray pipeline is a 379-mile, regulated natural gas pipeline system that transports natural gas and condensate from certain production areas located in the Gulf of Mexico offshore Louisiana to onshore transmission systems located in south Louisiana. This system includes a natural gas dehydration facility connected to the onshore terminus of the pipeline in south Louisiana. Shell is the operator of this pipeline and related dehydration facility.

Manta Ray. The Manta Ray system comprises approximately 235 miles of unregulated natural gas pipelines and related equipment located in the Gulf of Mexico offshore Louisiana. The primary sources of throughput for the Manta Ray system are the Green Canyon, Ship Shoal, South Timbalier, Grand Isle and Ewing Bank areas of the Gulf of Mexico offshore Louisiana. We expect that natural depletion of these fields will be partially offset by the addition of volumes from the Southern Green Canyon development, which is forecast to begin production in late 2004. Shell operates this system.

Nautilus. The Nautilus system comprises 101 miles of regulated pipelines located in the Gulf of Mexico offshore Louisiana. Currently, the primary source of natural gas throughput for the Nautilus system is production from the Manta Ray system through its interconnection in the Ship Shoal 207 area of the Gulf of Mexico offshore Louisiana. Shell is the administrative agent and Marathon the operator for this system.

Nemo. The Nemo pipeline is a 24-mile pipeline that transports natural gas volumes from Shell s Green Canyon development to an interconnect with Manta Ray. Shell operates this system.

Offshore natural gas pipeline utilization

The maximum amount of natural gas that these systems can transport per day depends upon the operating balance achieved at a given time between various segments of each 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 a system cannot be practically determined. In light of the complex, interconnected nature of the pipeline networks and the varying diameter of pipe used and pressure employed, the utilization rates of our principal offshore natural gas pipeline systems are measured in BBtus per day of natural gas transported. As shown in the following table, the utilization rates of our principal offshore natural gas pipelines are measured in terms of throughput (in BBtus per day, on a net basis).

	For Year Ended December 31,		
	2003	**2002**	**2001**
Stingray	228	265	300
Manta Ray, Nautilus and Nemo	205	235	266
Total net volume of natural gas pipelines	433	500	566

Onshore Natural Gas Pipelines & Services

At December 31, 2003, our Onshore Natural Gas Pipelines & Services business segment primarily consisted of 1,042 miles of natural gas pipelines that we either own or have an equity interest in.

Our onshore natural gas pipeline systems provide for the gathering, transmission and storage of natural gas from offshore and onshore Louisiana developments. Typically, these systems receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas at other points throughout the system. Generally, natural gas pipeline transportation agreements generate revenue for these systems based on a transportation fee per unit of volume (generally in MMBtus) transported. Natural gas pipelines (such as our Acadian Gas System) 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 subsidiary is exposed to commodity price risk to the extent it takes title to natural gas volumes through certain of its contracts.

Within their market area, our onshore systems compete with other natural gas pipeline companies on the basis of price (in terms of transportation rates and/or natural gas selling prices), service and flexibility. Our competitive position within the onshore market is positively affected 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 Louisiana pipelines have historically experienced slightly higher throughput rates during the winter and summer months. During the winter, natural gas consumption by residential and industrial users for heating is greater due to the decline in temperatures. During the summer, natural gas consumption by gas-fired electrical generation facilities is greater due to an increase in air conditioning demand.

Our onshore systems are 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 oil and gas fields 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 fields.

The following table summarizes our onshore natural gas pipeline transportation and distribution networks at December 31, 2003. Our ownership interest in each pipeline is held directly through a consolidated subsidiary or indirectly through a company in which we have an investment accounted for under the equity method.

Onshore Natural Gas Pipelines	**Length in Miles**	**Our Ownership Interest at December 31, 2003**
Acadian Gas System:		
Cypress	577	100.0%
Acadian	438	100.0%
Evangeline	27	49.5%
Total Acadian Gas System	1,042	

Acadian Gas System. The Acadian Gas System is a 1,042-mile pipeline system consisting of three natural gas pipelines that we operate: the 577-mile Cypress pipeline, 438-mile Acadian pipeline, and the 27-mile Evangeline pipeline. This system is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. We also lease a natural gas storage facility with approximately 3 Bcf of capacity that is an integral part of this system.

The Acadian Gas System links supplies of natural gas from Gulf of Mexico production (through connections with offshore pipelines) and various onshore developments to industrial, electric and local gas distribution customers primarily located in Louisiana. In addition, this system has interconnects with twelve interstate and four intrastate pipeline companies and a bi-directional interconnect with the U.S. natural gas marketplace at the Henry Hub. In general, the natural gas transported by the Acadian Gas System originates from onshore Louisiana sources and offshore Gulf of Mexico production areas.

Natural gas pipeline utilization

The exact capacity of a system cannot be practically determined due to the same limitations and complicating factors discussed above within the *Offshore natural gas pipeline utilization* section of this *Item 1 and 2. Business and Properties* section. As shown in the following table, the utilization rates of our onshore natural gas pipelines are measured in terms of throughput (in BBtus per day, on a net basis).

	For Year Ended December 31,		
	2003	**2002**	**2001**
Acadian Gas System	599	701	783

NGL Pipelines & Services

At December 31, 2003, our NGL Pipelines & Services business segment is comprised of (i) our natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating an approximate 11,644 miles and related storage facilities, and (iii) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our NGL import and export terminaling operations.

Natural Gas Processing and related NGL marketing activities

At the core of our natural gas processing business are twelve processing plants located on the Louisiana and Mississippi Gulf Coast with a total natural gas processing capacity of 11.56 Bcf/d. The following table lists our natural gas processing plants, gross and net processing capacities and our ownership interest in each facility at December 31, 2003.

Natural Gas Processing Facility	Location	Total Plant Gas Processing Capacity (Bcf/d)	Our Ownership Interest at December 31, 2003 (1)	Net Gas Processing Capacity (Bcf/d) (2)
Yscloskey	Louisiana	1.85	30.4%	0.56
Toca	Louisiana	1.10	59.9%	0.51
Venice	Louisiana	1.30	13.1%	0.48
North Terrebonne	Louisiana	1.30	31.3%	0.41
Pascagoula	Mississippi	1.00	40.0%	0.40
Calumet	Louisiana	1.60	32.4%	0.33
Neptune	Louisiana	0.30	66.0%	0.20
Sea Robin	Louisiana	0.90	15.5%	0.21
Burns Point	Louisiana	0.16	50.0%	0.08
Blue Water	Louisiana	0.95	7.4%	0.06
Iowa	Louisiana	0.50	2.0%	0.01
Patterson II	Louisiana	0.60	1.9%	0.01
	Total	11.56		3.26

(1) We own direct consolidated interests in these facilities with the exception of Venice, which is part of our investment in VESCO.

(2) Net gas processing capacity does not necessarily correspond to our ownership interest. It is based on a variety of factors including volumes processed at facility, ownership interest, contractual arrangements and other factors.

Our natural gas processing facilities are primarily straddle plants situated on mainline natural gas pipelines that bring unprocessed natural gas production from the Gulf of Mexico onshore. These facilities allow us to extract NGLs from a raw natural gas stream which enable the natural gas to meet pipeline quality specifications. 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.

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

Margin-band/keepwhole 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 for 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 payment we make to a producer for PTR is generally based on the price of natural gas multiplied by the quantity of PTR extracted or used. 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 PTR costs (which are generally limited, 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.

The most significant contract affecting our natural gas processing business is the Shell agreement, which is a margin band, or modified keepwhole arrangement 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 March 1, 2003. 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 mechanism (termed Consideration Adjustment Outside of Normal Operations or CAONO) to adjust the value of the PTR we reimburse to Shell. The CAONO, in effect, protects us from processing Shell s natural gas at an economic loss when the value of the mixed NGLs we extract is less than the sum of the cost of the PTR reimbursement, operating costs of the gas processing facility and other costs such as NGL fractionation and pipeline fees.

Approximately 50% of the natural gas volumes we currently process are covered by the margin-band arrangement that we have with Shell. During 2003, we reduced our use of traditional keepwhole arrangements from approximately 70% to less than 5%, which excludes the 50% we process under Shell s margin-band arrangement. Prior to its amendment in March 2003, the Shell contract was a traditional keepwhole arrangement.

Percent-of-liquids contracts. Under this type of agreement, we take ownership of a percentage of mixed NGLs extracted from a producer s natural gas stream. The producer retains title to the remaining percentage of mixed NGLs extracted and is responsible for the cost of PTR 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.

As of December 31, 2003, approximately 40% of the natural gas volumes we process are done so under percent-of-liquids contracts. During 2003, we increased the volume of natural gas processed under these arrangements from approximately 30% to 40% in an effort to reduce our use of traditional keepwhole arrangements.

Fee-based contracts. Under this type of agreement, we earn a fee based on the volume of natural gas we process. The producer retains title to 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.

As of December 31, 2003, approximately 15% of the natural gas volumes we process are done so under fee-based contracts. During 2003, we increased the volume of natural gas processed under these arrangements from less than 5% to approximately 15% in an effort to reduce our use of traditional keepwhole contracts.

In general, keepwhole and percent-of-liquids 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 we would take ownership of. 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.

Due to the increase in natural gas prices relative to NGL prices in recent years, there is an industry trend that new gas processing contracts on the U.S. Gulf Coast are being structured as either percent-of-liquids arrangements, fee-based arrangements or hybrid arrangements. A hybrid arrangement typically calls for the processor to provide processing services under a percent-of-liquids arrangement with the producer having the processing election. If the producer elects to not process under the percent-of-liquids arrangement, the processor has the option to process the gas under a keepwhole arrangement. If the processor elects to not exercise its option to process under a keepwhole arrangement, the gas is processed under a fee-based arrangement. We believe that providing natural gas processing services under these types of arrangements significantly reduces the risk and inherent fluctuation in our gross operating margin from natural gas processing caused by changes in natural gas and NGL prices.

The following table shows our net natural gas processing volumes and the corresponding overall utilization rates of our net natural gas processing capacity for each of the last three years. 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,		
	2003	**2002**	**2001**
Net natural gas processing volume (Bcf/d)	2.06	2.15	2.28
Net natural gas processing capacity (Bcf/d)	3.26	3.37	3.25
Utilization rate	63%	64%	70%
Equity NGL production (MBPD) [1]	56	73	63

(1) Equity NGL production rates for 2003 and 2001 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 review the *Product and Commodity Price Information* table in *Management s Discussion and Analysis of Financial Condition and Results of Operations - Our Results of Operations* on page 51 of this current report.

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 are 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 market value for or replace the PTR extracted from the natural gas stream, we are exposed to various risks, primarily that of 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 margin band/keepwhole arrangements to withhold processing services from a customer should we and the producer be unsuccessful in reaching acceptable contractual arrangements.

Our 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 issues. Our integrated system affords us flexibility in meeting our customers needs. While many companies participate in the 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 and/or leading strategic position and sizeable presence in these downstream businesses allows us to extract incremental value while offering our customers enhanced services, including comprehensive service packages.

At December 31, 2003, our NGL marketing activities utilize a fleet of approximately 670 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.

This segment includes our 13.1% investment in VESCO, which owns an integrated complex comprised of the Venice gas processing plant, a fractionation facility, storage assets and gas gathering pipelines in the Gulf of Mexico. In addition, we own four NGL terminals (primarily in propane service) located in Bakersfield and Rocklin, California; Reno, Nevada and Albertville, Alabama that have an aggregate storage capacity of 0.1 million barrels of NGLs.

NGL pipelines and storage

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 rates 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. Conversely, mixed NGL transportation volumes are generally lower during the winter months as traditionally higher natural gas prices negatively affect NGL extraction economics at natural gas processing plants connected to the pipelines. In addition, volumes on the Lou-Tex NGL pipeline are generally higher during the April through September period due to gasoline blending activities at refineries in anticipation of the summer driving season.

The following table summarizes our NGL pipeline transportation and distribution networks at December 31, 2003. 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.

NGL and Petrochemical Pipelines	Length in Miles	Our Ownership Interest at December 31, 2003
Mid-America Pipeline System	7,226	98.0%
Dixie	1,301	19.9%
Seminole	1,281	78.4%(1)
Louisiana Pipeline System	655	Various(2)
Promix(3)	410	33.3%
Lou-Tex NGL	206	100.0%
HSC	175	100.0%
Tri-States	169	50.0%(4)
Chunchula	143	100.0%
Belle Rose	48	41.7%
Wilprise	30	74.7%(5)
Total NGL and petrochemical pipelines	11,644	

(1) We acquired an additional 10% ownership interest in Seminole from Texaco in May 2004, which increased our ownership interest in Seminole to 88.4%.
(2) Of the 655 total miles for this system, we own 100% of 559 miles; 32.2% of 43 miles; and 31.3% of the remaining 53 miles.
(3) The Promix gathering pipeline is an integral component of the NGL fractionation activities of Promix.
(4) We acquired an additional 16.7% ownership interest in Tri-States from Williams in October 2003 and an additional 16.7% ownership interest in Tri-States from Koch in April 2004. We currently have a 66.7% ownership interest in Tri-States
(5) We acquired an additional 37.4% ownership interest in Wilprise from Williams in October 2003.

Mid-America Pipeline System. The Mid-America Pipeline System (or Mid-America) is a regulated 7,226-mile 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. We have operated this system since February 2003.

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 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 mixed 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 1,301-mile 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 currently estimate that Dixie transports approximately 50% of the propane requirements in the markets it serves. An affiliate of ConocoPhillips operates the pipeline.

Seminole. Seminole is 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 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. We have operated this pipeline since February 2003.

Louisiana Pipeline System. The Louisiana Pipeline System is a 655-mile 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. We operate all but 43 miles of this system.

Promix. The Promix pipeline is a 410-mile NGL gathering pipeline that gathers mixed NGLs from 12 natural gas processing plants in Louisiana for delivery to the Promix NGL fractionator. This pipeline is an integral part of the Promix NGL fractionation facility.

Lou-Tex NGL. The Lou-Tex NGL pipeline system consists of a 206-mile NGL pipeline 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. We operate this pipeline.

HSC. The HSC pipeline system is a collection of NGL and petrochemical pipelines aggregating 175 miles in length extending from our Houston Ship Channel import/export terminal 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. This system is also used to transport MTBE produced by BEF to delivery locations along the Houston Ship Channel. We operate this system.

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

The Tri-States pipeline is a l69-mile NGL pipeline that extends from Mobile Bay, Alabama to near Kenner, Louisiana and is operated by BP. The Belle Rose pipeline is a 48-mile NGL pipeline operated by us that extends from the interconnect with the Tri-States pipeline near Kenner, Louisiana to the Promix NGL fractionator. The Wilprise pipeline is a 30-mile NGL pipeline that extends from the interconnect with the Tri-States pipeline near Kenner, Louisiana to Sorrento, Louisiana. We have operated the Wilprise pipeline since February 2003.

Chunchula. The Chunchula pipeline system is a 143-mile NGL pipeline extending from the Alabama-Florida border to our storage facilities in Petal, Mississippi for further distribution. We operate this pipeline.

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 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. As shown in the following table, the utilization rates of our principal NGL pipelines are measured in terms of throughput (in MBPD, on a net basis).

	For Year Ended December 31,		
NGL and Petrochemical Pipelines	**2003**	**2002**	**2001**
Mid-America Pipeline System [(1)]	580	641	n/a
Dixie	21	21	26
Seminole [(1)]	194	202	n/a
Louisiana Pipeline System	190	179	138
Lou-Tex NGL	36	38	29
HSC	136	134	133
Tri-States, Wilprise and Belle Rose	35	44	36
Chunchula	4	5	5
Total net volume of NGL and petrochemical pipelines	1,196	1,264	367

(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).

When compared to 2002, throughput rates for certain of our NGL pipelines in 2003 were lower due to a combination of (i) decreased demand for NGLs by the petrochemical industry and (ii) lower NGL extraction rates at domestic natural gas processing facilities. Volumes recorded for the Mid-America and Seminole systems were particularly affected by lower NGL extraction rates by natural gas processing facilities located in the Rocky Mountains.

NGL and petrochemical storage

Our NGL and petrochemical storage facilities are integral parts of our pipeline 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.

Our principal storage operations are primarily determined by the operational requirements of our customers in the petrochemical industry. 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 the practical (or useable) capacity of the storage assets we utilize and our ownership of such practical capacity by state at December 31, 2003.

NGL and Petrochemical Storage Assets by State	Practical Capacity, MMBbls	Our Ownership of Practical Capacity, MMBbls
Texas	94.1	93.8
Louisiana	32.5	14.3
Mississippi	12.0	9.5
Iowa	0.5	0.5
Nebraska	0.3	0.3
Oklahoma	0.1	0.1
Total NGL and petrochemical storage capacity	139.5	118.5

Our primary storage facilities are located at Mont Belvieu, Texas. We own and operate 90.5 MMBbls of practical storage capacity at Mont Belvieu. We also own storage facilities located at Breaux Bridge, Napoleonville, Sorrento and Venice, Louisiana having a practical capacity of 32.5 MMBbls. Our Mississippi storage assets are comprised of facilities located at or near Petal and Hattiesburg having a practical capacity of 12 MMBbls. Of the facilities located in Louisiana and Mississippi, we operate those located in Breaux Bridge and Napoleonville, Louisiana and Petal, Mississippi. Affiliates of Dynegy and Shell operate the remaining facilities. In connection with our Mid-America and Seminole pipeline systems, we own 20 underground NGL and petrochemical storage wells located in four states. The Mid-America and Seminole storage facilities have a practical storage capacity of 4.5 MMBbls.

Our storage wells allow us to optimize throughput on our pipeline systems and maintain operational efficiency. When used in conjunction with our processing plant operations, storage wells allow us to mix various batches of feedstock and maintain both a sufficient supply and stable composition of feedstock to our fractionation facilities. 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 marketing activities for their use of the storage facilities. These intrasegment revenues and expenses are eliminated in consolidation.

We also store products for customers in our wells for a fee. The amount of storage capacity available for this type of storage activity varies daily depending on our processing requirements. Our competitors in this area are other storage and pipeline companies such as TEPPCO and Dynegy. Major oil and gas companies such as Exxon Mobil and ConocoPhillips occasionally use their proprietary storage assets in this role, thereby entering into competition with us and other providers. We compete with other service providers primarily in terms of the fees charged, pipeline connections and dependability. We believe that the integrated nature of our processing, pipeline and import/export operations provide our storage customers access to a competitively priced, flexible and dependable network of assets.

NGL import and export facilities

Houston Ship Channel Import/Export Terminal. We lease and operate an NGL import facility located on the Houston Ship Channel that 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 facility is primarily used to offload volumes bound for our facilities in Mont Belvieu. Import volumes are usually at their highest levels from April through September of each year due to lower international demand and pricing for NGLs relative to domestic levels in those months. Typically, our import cargoes originate from North Africa and North Sea production areas.

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 exporters. Our export facility can load vessels with refrigerated propane and butane at rates up to 5,000 barrels per hour. In general, export cargoes shipped from this facility are destined for Mexico, Central and South America, Europe and the Far East (Japan, Korea and China). Export volumes are generally higher during the winter months due to increased propane exports.

Dynegy and Dow own facilities that are the primary competitors of our NGL import facility. Our primary competitors in the NGL export services market are Dynegy and ChevronTexaco. Both the import and export operations compete with third-party operations primarily in terms of service, such as the ability to quickly load or offload vessels. Our competitive position is enhanced because our extensive storage and pipeline assets at Mont Belvieu allow us to load and offload ships very efficiently. The profitability of import and export activities primarily depends upon the quantities loaded and offloaded and the fees we charge associated with each activity.

Due to the timing and logistics of ship and barge loading and offloading activities, we measure utilization in terms of volumes loaded and offloaded through our import/export facilities. The following table shows the volume for each facility over the last three years (in MBPD, on a net basis):

	For Year Ended December 31,		
	2003	**2002**	**2001**
Houston Ship Channel NGL import facility	64	22	45
Houston Ship Channel NGL export facility [(1)]	15	19	8
Total imports and exports	79	41	53

(1) Prior to March 2003, we owned 50% of this facility through our equity investment in EPIK. On March 1, 2003, we acquired the remaining 50% ownership interests in this facility. Since acquiring these remaining interests, 2003 export rates have averaged 9 MBPD. Export volumes for 2002 and 2001 reflect our 50% ownership interest in EPIK during those periods.

NGL Fractionation

NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane and natural gasoline. 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. 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 MTBE, and in the production of propylene oxide. 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. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

The three principal sources of mixed NGLs fractionated in the United States are (1) domestic gas processing plants, (2) domestic crude oil refineries and (3) imports of butane and propane mixtures. When produced at the wellhead, natural gas consists of a mixture of hydrocarbons that must be processed to remove NGLs and impurities to render the gas suitable for pipeline transportation. Gas processing plants are located near the production areas and separate pipeline quality natural gas (principally methane) from mixed NGLs and other components. After being extracted from natural gas, mixed NGLs are typically transported to a centralized facility for fractionation. Recoveries of mixed NGLs by gas processing plants represent the largest source of volumes processed by our NGL fractionators and are generally governed by pipeline quality specification for natural gas and the degree to which NGL prices exceed the cost (principally that of natural gas as a feedstock and as a fuel) of separating the mixed NGLs from the natural gas stream. 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.

Crude oil and condensate production also contain varying amounts of NGLs, which are removed during the refining process and are either fractionated by the refiners themselves or delivered to third-party NGL fractionation facilities like those owned by us. The mixed NGLs delivered from domestic 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. We also take delivery of mixed NGL imports through our Houston Ship Channel import terminal, which is connected to our Mont Belvieu complex via pipeline.

Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from Gulf Coast gas processing plants, will be available for fractionation in 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. 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 Rocky Mountain Overthrust and 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 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. We compete with a number of NGL fractionators in Texas, Louisiana and Kansas. Our Mont Belvieu NGL fractionator competes directly with three local facilities having an estimated combined processing capacity of 440 MBPD and indirectly with two other Texas facilities having a combined processing capacity of 210 MBPD. In addition, our facilities compete on a more limited basis with facilities in Kansas and several facilities in Louisiana. Finally, we also compete with a number of producers who operate small NGL fractionators at individual field processing facilities.

The following table summarizes our NGL fractionation assets at December 31, 2003. Our ownership interest in each NGL fractionator 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.

NGL Fractionation Facility	Location	Total Plant Capacity, MBPD	Our Ownership Interest at December 31, 2003	Net Capacity, MBPD
Mont Belvieu	Texas	210	75.0%	158
Promix	Louisiana	145	33.3%	48
Norco	Louisiana	75	100.0%	75
BRF	Louisiana	60	32.2%	19
VESCO(1)	Louisiana	36	13.1%	5
Tebone	Louisiana	30	31.3%	9
Total		556		314

(1) This NGL fractionator is an integral part of the operations of our VESCO investment.

We idled our Toca-Western and Petal NGL fractionators during 2003 for economic reasons. The Toca-Western facility was decommissioned in August 2003 and its volumes redirected to our Norco NGL fractionator. Rerouting the mixed NGLs that were processed at Toca-Western to Norco allowed us to utilize spare capacity at our larger Norco facility resulting in incremental cost-savings from a more efficient use of our assets. The Petal NGL fractionation facility was decommissioned in December 2003 after management decided that this facility did not fit into our long-range plans due to poor economics of continued operations at the site. Volumes historically processed at Petal have been redirected to either our Mont Belvieu or Norco facilities. The total plant capacity of the Toca-Western and Petal NGL fractionators was 14 MBPD and 7 MBPD, respectively.

Mont Belvieu. We operate 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. This hub is adjacent to the largest concentration of refineries and petrochemical plants in North America and is located on a large naturally occurring salt dome that provides for the underground storage of significant quantities of NGLs.

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 with Burlington Resources, Duke and Texaco (which accounted for 93 MBPD of net volume in 2003). Additionally, we have negotiated a ten-year fractionation contract with Williams that will bring 40 MBPD of processing volume to the facility beginning in October 2004.

Promix. We operate and own a 33.3% interest in Promix, which owns a 145 MBPD NGL fractionation facility located near Napoleonville, Louisiana. Promix includes a 410-mile mixed NGL gathering system connected to twelve gas processing plants, five NGL salt dome storage wells 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 the Belle Rose and Tri-States pipelines.

Norco. We own and operate an NGL fractionation facility at Norco, Louisiana. The Norco facility receives mixed NGLs via pipeline from the Yscloskey and Toca natural gas processing plants in Louisiana and from other natural gas processing plants and refineries via pipelines and has a gross capacity of 75 MBPD. During 2003, long-term percent-of-liquids contracts exclusive to this facility accounted for approximately 29 MBPD of processing volume.

BRF. We operate and own a 32.2% interest in BRF, which owns a 60 MBPD NGL fractionation facility and related pipeline transportation assets located near Baton Rouge, Louisiana. The BRF facility processes mixed NGLs provided by the co-owners of the facility (Williams, BP and Exxon Mobil) 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. This NGL fractionator is an integral part of the natural gas processing operations of VESCO.

Tebone. We operate and own a 31.3% interest in a 30 MBPD NGL fractionation facility located in Ascension Parish, Louisiana. The Tebone NGL fractionation facility was built in the 1960s and receives NGLs from the North Terrebonne gas processing plant.

NGL fractionator utilization

The following table shows net fractionation volumes and capacity (in MBPD) and the corresponding overall utilization rates of our NGL fractionation facilities for the last three years. Net capacity amounts have been adjusted for the timing of acquisitions and facility closures.

	For Year Ended December 31,		
NGL Fractionation Facility	**2003**	**2002**	**2001**
Mont Belvieu	134	127	110
Promix	24	30	30
Norco	42	41	41
BRF	11	17	14
Other	16	20	9
Total net volume	227	235	204
Net capacity	324	313	290
Utilization rate	70%	75%	70%

Petrochemical Services

At December 31, 2003, our Petrochemical Services segment would have been comprised of our butane isomerization, propylene fractionation and octane enhancement businesses.

Butane isomerization

Our isomerization business includes three butamer reactor units and eight associated deisobutanizer units located in Mont Belvieu, Texas, which comprise the largest commercial isomerization complex in the United States, and 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 the isomerization facilities with the exception of one of the deisobutanizer units, which we control through a lease. We operate the facilities. We hold a 100% ownership interest and operate the 70-mile Port Neches pipeline, which was acquired in March 2003.

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.

Customers utilizing the services provided by these facilities include third parties, BEF and our NGL Pipelines & Services segment s NGL marketing activities. Our larger third-party toll processing customers generally operate under long-term contracts in which they supply normal butane feedstock and pay us toll processing fees based on the volume of isobutane produced. These facilities also produce high purity grade isobutane under toll processing agreements to meet BEF s feedstock requirements. The isomerization facilities are also used by our NGL Pipelines & Services segment s NGL marketing activities to convert normal and/or mixed butanes into isobutane in order to satisfy isobutane sales contracts. The intersegment tolling revenues we record for these services in our isomerization business and the corresponding expense to our NGL marketing activities are eliminated in consolidation. During 2003, 17 MBPD of isobutane production was attributable to our NGL marketing activities, 10 MBPD to BEF-related contracts, with the balance related to various toll processing arrangements.

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

	For Year Ended December 31,		
Mont Belvieu Isomerization Facility	**2003**	**2002**	**2001**
Production	77	84	80
Net capacity	116	116	116
Utilization rate (1)	66%	72%	69%

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

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.

Propylene fractionation

Our propylene fractionation business consists of three fractionation facilities in Texas, an equity interest in the Baton Rouge Propylene Concentrator (BRPC) propylene fractionation facility in Louisiana, the Olefins Terminal Corporation (OTC) propylene export facility in Seabrook, Texas, and approximately 416 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. Approximately 50% of the demand for polymer grade propylene is attributable to 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 propylene fractionation units have been designed to be energy cost efficient which allows us to be competitive in terms of processing fees. In addition, our facilities are connected to extensive pipeline transportation and storage facilities, which provide our customers with operational flexibility. Our petrochemical marketing activities encounter competition from fully integrated oil companies and various petrochemical companies. Each of our petrochemical marketing competitors have varying levels of financial and personnel resources and competition generally revolves around price, service, logistics and location issues.

The following table summarizes our propylene fractionation assets and ownership at December 31, 2003. 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.

Propylene Fractionation Facility	Location	Total Plant Capacity, MBPD	Our Ownership Interest at December 31, 2003	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		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.

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 long-term 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 2003, 11 MBPD of our net polymer grade propylene production was associated with toll processing operations with the balance attributable to petrochemical marketing activities.

At December 31, 2003, approximately 75% of the feedstock requirements of these facilities were under long-term supply contracts, with the remaining 25% being met through spot market purchases. The majority of the feedstock volumes originate from refineries along the Gulf Coast and in the Mid-Continent regions of North America. We can unload barges carrying refinery grade propylene using our import terminal located on the Houston Ship Channel. In addition, we can receive supplies of refinery grade propylene through our Mont Belvieu truck and rail unloading facility and from refineries and other producers connected to our HSC pipeline and Lou-Tex Propylene systems and from other third party pipelines. In turn, polymer grade propylene is transported to customers by truck or pipeline. We can also export volumes of polymer grade propylene using our OTC facility.

BRPC. We operate and own a 30.0% interest in BRPC, which owns a 23 MBPD chemical grade propylene production facility located near Baton Rouge, Louisiana. This unit, located across the Mississippi River from Exxon Mobil s refinery and chemical plant, fractionates refinery grade propylene produced by Exxon Mobil into chemical grade propylene for a toll-processing fee. The results of operation of BRPC depend upon the volume of refinery grade propylene processed and the level of fees we charge Exxon Mobil.

The following table shows net fractionation volumes and capacity (in MBPD) 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, 2003	2002	2001
Mont Belvieu [1]	53	52	27
BRPC	4	4	4
Total net volume	57	56	31
Net capacity	65	63	38
Utilization rate	88%	89%	82%

(1) Net processing volumes for 2002 were higher than 2001 due to the acquisition of Splitter III in February 2002.

Propylene pipelines and export terminal

The following table summarizes our propylene pipeline transportation and distribution networks at December 31, 2003. 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.

Propylene Pipelines	Length in Miles	Our Ownership Interest at December 31, 2003
Lou-Tex Propylene	291	100.0%
Lake Charles/Bayport	87	50.0% [1]
Sabine Propylene	21	100.0%
La Porte [2]	17	50.0%
Total NGL and petrochemical pipelines	416	

(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.

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. We operate this system.

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. We operate this system.

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. We operate this 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. We operate this pipeline, which is an integral part of our Mont Belvieu propylene fractionation activities.

OTC Propylene Export Facility. We own and operate 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 ChevronTexaco located on the Houston Ship Channel. OTC s operations are an integral part of our Mont Belvieu propylene fractionation business.

Propylene pipeline and export terminal utilization

Utilization rates of our propylene pipelines are measured in terms of throughput. Utilization rates for OTC are measured in terms of volumes loaded. The following table shows the volume for each asset over the last three years (in MBPD, on a net basis):

	For Year Ended December 31,		
NGL and Petrochemical Pipelines	2003	2002	2001
Lou-Tex Propylene	29	25	27
Lake Charles/Bayport	13	11	6
Sabine Propylene [1]	11	11	n/a
OTC	3	4	n/a
Total net volume of propylene throughput	56	51	33

(1) Our Sabine Propylene pipeline commenced operations during the first quarter of 2002.

Octane enhancement

At December 31, 2003, we owned a 66.7% interest in Belvieu Environmental Fuels (BEF), which owns a facility that currently produces MTBE, a motor gasoline additive that increases octane and is used in reformulated motor gasoline. 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.

The production of MTBE is 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 currently 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.

As noted above, domestic MTBE demand is primarily linked to reformulated motor gasoline requirements in certain urban areas of the United States designated as carbon monoxide and ozone non-attainment areas by the federal Clean Air Act Amendments of 1990. Motor gasoline demand in turn is affected by many factors, including the price of motor gasoline (which is generally dependent upon crude oil prices) and overall economic conditions. Prior to September 2004, Sun was obligated to purchase all of BEF s MTBE production at spot-market related prices. Sun uses the MTBE it purchases from BEF to either (i) satisfy its own reformulated gasoline blending requirements in the eastern United States markets it serves, or (ii) as a commodity offered for resale to others.

BEF is exposed to commodity price risk due to the market-pricing provisions of the Sun agreement. Historically, MTBE prices are stronger during the April to September period of each year, which corresponds with the summer driving season. Future MTBE prices will be influenced by the timing and extent of federal and state legislation to ban or limit the use of MTBE.

BEF manufactures MTBE using feedstocks of methanol and high-purity isobutane. The methanol feedstock used by BEF is purchased from third parties and transported to Mont Belvieu using our HSC pipeline. BEF s methanol supply can originate from a variety of domestic and foreign producers, including those located in Venezuela, Chile, New Zealand and the Caribbean. BEF s high-purity isobutane requirements are met using production from our Mont Belvieu isomerization units. Lastly, BEF s MTBE production is transported using our HSC Pipeline to a location on the Houston Ship Channel for delivery to Sun.

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.

BEF s assets were written down to fair value using fair value analysis, 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 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.

The following table shows MTBE production volumes and capacity (in MBPD) and the corresponding overall utilization rates of the BEF facility for the last three years. Net capacity for 2003 has been adjusted for our September 2003 acquisition of the additional 33.3% interest in the facility.

	For Year Ended December 31,		
BEF Facility	**2003**	**2002**	**2001**
Gross MTBE production capacity	16.5	16.5	16.5
Net MTBE production capacity	7.0	5.5	5.5
Net MTBE production volume	4.4	5.1	4.7
Utilization rate	62%	94%	85%

EMPLOYEES

We do not have any employees. EPCO employs most of the persons necessary for the operation of our business. At December 31, 2003, EPCO had approximately 1,325 employees involved in the management and operations of our business, none of whom where members of a union. We fully reimburse EPCO for the costs of approximately 1,220 of these employees, with the remainder of this group covered under the fixed-fee payments we made under the Administrative Services Agreement prior to January 1, 2004 (for a detailed discussion of the Administrative Services Agreement, please read Item 13 of this annual report). In addition to EPCO employees, we have engaged approximately 125 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 5.5%, 7.9% and 10.6% of consolidated revenues in 2003, 2002 and 2001, respectively.

REGULATION AND ENVIRONMENTAL MATTERS

Regulation of our interstate common carrier liquids pipelines

Our Mid-America, Seminole, Chunchula, Lou-Tex Propylene, Lou-Tex NGL, Propylene and Sabine 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 Federal Energy Regulatory Commission (FERC) under the October 1, 1977 version of the Interstate Commerce Act (ICA).

As interstate common carriers, these 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 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 petroleum pipeline rates that were in effect during any of 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 oil 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. At present these provisions and the circumstances under which a grandfathered rate may be successfully challenged have received only limited attention from the FERC, causing a degree of uncertainty as to their application and scope. However, two cases involving SFPP, L.P. (SFPP), un unrelated interstate common carrier oil pipeline, that are pending before the U.S. Court of Appeals for the District of Columbia Circuit and the FERC may resolve some of that uncertainty. Portions of the Mid-America, Seminole, Chunchula and Propylene pipelines and portions of the Louisiana Pipeline System are covered by the grandfathering provisions of the Energy Policy Act.

The Energy Policy Act required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for petroleum pipelines, and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by issuing Order No. 561, which, among other things, adopted an indexing rate methodology for petroleum pipelines. Under the regulations, which became effective January 1, 1995, petroleum 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 pipeline to reduce its rate to comply with the lower ceiling. Under Order No. 561, a pipeline must 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. These alternatives may be used in certain specified circumstances.

We believe that the rates charged for transportation services on the interstate pipelines we own or have an interest in are just and reasonable under the ICA. As discussed above, however, because of the uncertainty related to the application of the Energy Policy Act s grandfathering provisions as well as the uncertainty related to the FERC s indexing methodology, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier 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.

In a 1995 decision involving Lakehead Pipe Line Company (Lakehead), an unrelated pipeline limited partnership, the FERC partially disallowed the inclusion of income taxes in that partnership s cost of service. Subsequent appeals of these rulings were resolved by settlement and were not adjudicated. In a separate proceeding involving SFPP, the FERC held that the limited partnership may not claim an income tax allowance for income attributable to non-corporate partners, both individuals and other entities. As noted above, SFPP and other parties to the proceeding have appealed the FERC s order to the U.S. Court of Appeals for the District of Columbia Circuit where the case is now pending. The effect of the FERC s policy stated in the Lakehead proceeding (and the results of the ongoing SFPP litigation regarding that policy) on us is uncertain. Our current rates are established using the indexing method and/or grandfather provisions. It is possible that a party might challenge our grandfathered rates (set when the assets were held by our corporate predecessor). While it is not possible to predict the likelihood that such a challenge would succeed at the FERC, if such a challenge were to be raised and succeed, application of the Lakehead decision and related rulings would reduce our permissible income tax allowance in any cost-of-service based rate, to the extent income tax is attributed to limited partnership interests held by individual partners rather than corporations.

Regulation of our interstate natural gas pipelines

The Stingray and Nautilus natural gas pipeline systems are regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each system operates under separate FERC-approved tariffs that establish rates, terms and conditions under which each system provides services to its customers. In addition, the FERC s authority over natural gas companies that provide natural gas pipeline transportation or storage services in interstate commerce includes the certification and construction of new facilities; the extension or abandonment of services and facilities; the maintenance of accounts and records; the acquisition and disposition of facilities; the initiation and discontinuation of services; and various other matters. As noted above, the Stingray and Nautilus systems 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.

Commencing in 1992, the FERC issued Order No. 636 and subsequent orders (collectively, Order No. 636), which require interstate pipelines to provide transportation and storage services separate, or unbundled, from the pipelines sales of gas. Also, Order No. 636 requires pipelines to provide open-access transportation and storage services on a basis that is equal for all shippers. The FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although the FERC continues to review and modify its open access regulations.

In 2000, the FERC issued Order No. 637 and subsequent orders (collectively, Order No. 637), which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. In April of 2002, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision that either upheld or declared premature for review most major aspects of Order No. 637. Order No. 637 required interstate natural gas pipelines to implement the policies mandated by the Order through individual compliance filings. The FERC has now ruled on a number of the individual compliance filings, although its decisions in such proceedings remain subject to the outcome of pending rehearing requests and possible court appeals. We cannot predict whether and to what extent FERC s market reforms will survive judicial review and, if so, whether the FERC s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. However, we do not believe that the operations of Nautilus and Stingray (or our other pipeline and storage operations which are indirectly affected by the extent and nature of

FERC s jurisdiction over activities in interstate commerce) will be affected in any materially different way than other companies with whom we compete.

In addition to its jurisdiction over Stingray and Nautilus under the Natural Gas Act and the Natural Gas Policy Act, the FERC also has jurisdiction over Stingray and Nautilus, as well as Manta Ray and Nemo, under the Outer Continental Shelf Lands Act (OCSLA). 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. We cannot predict what further action FERC 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. By June 1,2004, each transmission provider must comply with the standards of conduct and post procedures on its website that will enable the FERC to determine whether the transmission provider is in compliance with the new rules. Many aspects of the rules are the subject of requests for rehearing currently pending before the FERC. We cannot predict the ultimate outcome of this proceeding. We do not believe that implementation of the final rules will affect us in any materially different way than other companies with whom we compete.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Regulation of our intrastate common carrier liquids and natural gas pipelines

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. 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.

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.

General environmental matters

Our operations are subject to federal, state and local laws and regulations relating to the release of pollutants into the environment or otherwise relating to protection of the environment. We believe that our operations and facilities have all required permits and are in general compliance with applicable environmental regulations. However, risks of process upsets, accidental releases or spills are associated with our operations, and there can be no assurance that significant costs and liabilities will not be incurred, including those related to claims for damage to property and persons.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, such as discharges of pollutants, generation and disposal of wastes and the production, use and handling of chemical substances. The usual remedy for failure to comply with these laws and regulations is the assessment of administrative, civil and, in some cases, criminal penalties or, in rare cases, injunctions. We believe that the cost of compliance with environmental laws and regulations will not have a significant effect on our results of operations or financial position. However, it is possible that the costs of compliance with environmental laws and regulations will continue to increase, and there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts currently anticipated. In the event of future increases in cost, we may be unable to pass these increases on to customers. We will attempt to anticipate future regulatory requirements that might be imposed and plan accordingly in order to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance.

We currently own or lease, and have in the past owned or leased, properties that have been used over the years for NGL processing, treatment, transportation and storage and for oil and natural gas exploration and production activities. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, a possibility exists that hydrocarbons and other solid wastes may have been disposed of or otherwise released on various properties that we own or lease or have owned or leased during the operating history of those facilities. In addition, a small number of these properties may have been operated by third parties over whom we had no control as to such entities handling of hydrocarbons or other wastes and the manner in which such substances may have been disposed of or released. State and federal laws applicable to oil and natural gas wastes and properties have gradually become more strict; and, pursuant to such laws and regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. We do not believe that there presently exists significant surface or subsurface contamination of our properties by hydrocarbons or other solid wastes.

We generate both hazardous and nonhazardous solid wastes which are subject to requirements of the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. From time to time, the EPA has considered making changes in nonhazardous waste standards that would result in stricter disposal requirements for such wastes. Furthermore, it is possible that some wastes currently classified as nonhazardous may be designated as hazardous in the future, resulting in wastes being subject to more rigorous and costly disposal requirements. Such changes in the regulations may result in our incurring additional capital expenditures or operating expenses.

Potential impact of the Superfund law on our operations

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, and similar state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons, including the owner or operator of a site and companies that disposed or arranged for the disposal of hazardous substances found at the site. CERCLA also authorizes the EPA 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 parties the costs they incur. We may generate hazardous substances in the course of our normal business operations. As such, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed; however, we have not been notified of any potential responsibility for cleanup costs under CERCLA.

General impact of the Clean Air Act on our operations

Our operations are subject to the Clean Air Act and comparable state statutes. Amendments to the Clean Air Act were adopted in 1990 and contain provisions that may result in the imposition of certain pollution control requirements with respect to air emissions from our pipelines and processing and storage facilities. For example, the Mont Belvieu processing and storage facilities are located in the Houston-Galveston ozone non-attainment area, which is categorized as a severe area and, therefore, is subject to more restrictive regulations for the issuance of air permits for new or modified facilities. The Houston-Galveston area is among ten areas of the country in this severe category. One of the other consequences of this non-attainment status is the potential imposition of lower limits on emissions of certain pollutants, particularly oxides of nitrogen which are produced through combustion, such as in the gas turbines at the Mont Belvieu complex.

Regulations imposing more strict air emissions requirements on existing facilities in the Houston-Galveston area were issued in December 2000. These regulations may have required extensive redesign and modification of our Mont Belvieu facilities to achieve the air emissions reductions needed for federal Clean Air Act compliance. The technical practicality and economic reasonableness of these regulations were challenged under state law in litigation filed on January 19, 2001 against the predecessor of the Texas Commission on Environmental Quality (TCEQ) and its principal officials in the District Court of Travis County, Texas, by a coalition of major Houston-Galveston area industries that included us. This litigation was stayed by a settlement under which the TCEQ agreed to reassess the December 2000 rules in light of certain scientific studies of the sources and mechanisms of air pollution in the Houston-Galveston area that were undertaken during the summer of 2001.

As a result of these studies, the TCEQ promulgated new rules on December 13, 2002 that require less restrictive nitrogen oxide reductions for certain industrial sources in the Houston-Galveston area, including some of those we operate, than were required under the December 2000 rules. The December 2002 rules, however, require additional controls on sources of emissions defined as highly reactive volatile organic compounds, a class of chemicals that includes certain types of hydrocarbons handled at our facilities in the Houston-Galveston area. We believe that the result of the new rules will be to decrease our projected capital outlays and operating costs for air pollution control in the Houston-Galveston area compared to what would have been required under the December 2000 rules. There is no guarantee that the EPA will approve the new rules as part of the state implementation plan for the Houston-Galveston area, and there may be additional legal challenges to the new rules, either of which could result in additional rulemaking that could affect our operations.

As a result of our evaluation of the December 2002 rules, however, we expect that expenditures for air emissions reduction projects will be spread over several years, and we believe that adequate liquidity and capital resources will exist for us to undertake them. We have budgeted capital funds in 2004 to continue making modifications begun in 2002 to certain Mont Belvieu facilities that will result in air emission reductions. The methods employed to achieve these reductions will be compatible with whatever regulatory requirements are eventually put in place.

Failure to comply with air statutes or the implementing regulations may lead to the assessment of administrative, civil or criminal penalties, and/or result in the limitation or cessation of construction or operation of certain air emission sources. We believe our operations are in substantial compliance with applicable air requirements.

Impact of the Clean Air Act s oxygenated fuels programs on our BEF investment

We have a 66.7% ownership in BEF, which owns a facility currently producing MTBE. The production of MTBE is driven primarily by oxygenated fuels programs established under the federal Clean Air Amendments of 1990 and other legislation. In 1999 the governor of California ordered the phase-out of MTBE in California based on allegations by several public advocacy and protest groups that MTBE contaminates water supplies, causes health problems and has not been as beneficial in reducing air pollution as originally contemplated. 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 BEF. It is possible, however, that MTBE manufacturers such as BEF could ultimately be added as defendants in such lawsuits or in new lawsuits. While we believe that we currently have adequate insurance to cover any adverse consequences resulting from our production of MTBE, we have been informed by our insurance carrier that upon renewal of our policy in April 2004, MTBE related claims may be excluded from the scope of our insurance coverage.

California s complete ban on the use of MTBE in motor gasoline went into effect on January 1, 2004. New York and Connecticut also banned MTBE effective January 1, 2004. At least sixteen other states have enacted bans on MTBE, and Congress is also contemplating a federal ban on MTBE. In 2003, the House approved an energy bill that in part would have banned the use of MTBE beginning in 2014 and require the use of ethanol as a substitute for MTBE; this legislation was not enacted into law. Similar legislation is expected to be considered again in the second session of the current Congress, but the outlook for passage is uncertain.

Several refiners have taken an early initiative to phase out the production of MTBE in response to this legislative pressure and the possibility of additional groundwater contamination lawsuits. If MTBE is further banned or if its use is more significantly limited, the revenue BEF derives from MTBE production would be reduced or eliminated, which in turn would affect the earnings we record from BEF in our Petrochemical Services segment. Also, to the extent isobutane is used as a feedstock in the production of MTBE and this demand is reduced or eliminated due to bans on the use of MTBE, the revenues we record in our Petrochemical Services segment for isomerization services and in our NGL Pipelines & Services segment for sales of isobutane could be unfavorably impacted. However, isobutane would continue to be needed as a feedstock to the extent that alkylate or iso-octane replaces MTBE.

In view of the uncertainty surrounding the long term prospects for MTBE, in 2003 we announced plans to modify the BEF facility to add the capacity to produce iso-octane, a motor gasoline octane enhancement additive which is also derived from isobutane and is expected to be sought by refiners to replace the amount of octane that is lost as a result of MTBE being eliminated as a motor gasoline blendstock. We expect these modifications to be completed in the third quarter of 2004. We also continue to study the prospects for converting the BEF facility to the production of alkylate, another additive to increase octane in motor gasoline derived from isobutane. To the extent the BEF facility is used to produce iso-octane or alkylate, it would continue this facility s demand for isobutane and, thus, help offset the loss of MTBE-related revenues we record in our Petrochemical Services segment for isomerization services and in our NGL Pipelines & Services segment for sales of isobutane.

Legislation introduced in the U.S. Senate in 2003, as part of the energy bill, would have eliminated the Clean Air Act s oxygenate requirement in order to facilitate the elimination of MTBE in fuel by a certain date, while protecting the fuel alcohol market (primarily ethanol) through a renewable fuels mandate. Energy legislation introduced in the U.S. House of Representatives would have, among other things, protected manufacturers by prohibiting lawsuits based on allegations that MTBE is a defective product. The Energy legislation proposed by both the Senate and the House also included language authorizing (but not appropriating) conversion assistance to MTBE manufacturers such as BEF. The amount of potential conversion assistance was increased in both versions over the levels established in similar legislation in 2002. Neither of these pieces of legislation was enacted into law. The outlook for the second session of the current Congress is uncertain, and no assurance can be given as to whether or not the federal government or additional states will ultimately adopt legislation to remove the use of MTBE from their clean fuels programs or to provide liability protection for MTBE manufacturers.

Impact of the Clean Water Act on our operations

The Federal Water Pollution Control Act, also known as the Clean Water Act, and similar state laws regulate potential discharges of contaminants into federal and state waters. Regulations pursuant to these laws require companies that discharge into federal and state waters to obtain National Pollutant Discharge Elimination System (NPDES) and/or state permits authorizing these discharges. These laws provide penalties for releases of unauthorized contaminants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of stormwater runoff. The Clean Water Act also requires operators of facilities with underground or above ground oil storage capacity in excess of certain prescribed amounts to prepare and implement spill prevention, control and countermeasure (SPCC) plans. We believe that our operations are in substantial compliance with such laws and regulations.

Impact of environmental regulation on our underground storage operations

We currently own and operate underground storage caverns that have been created in naturally occurring salt formations in Texas, Oklahoma, Louisiana and Mississippi. We also own and operate underground storage caverns that have been created in subsurface limestone formations in Iowa and Nebraska. These storage caverns are used to store natural gas, NGLs, NGL products and various petrochemicals. Surface brine pits and brine disposal wells are used in the operation of the storage caverns. All of these facilities are subject to strict environmental regulation such as that provided by the Texas Natural Resources Code for those storage facilities situated in Texas and similar statutes in the other states in which such facilities are located. Regulations implemented under such statutes address the operation, maintenance and/or abandonment of such underground storage facilities, pits and disposal wells, and require that permits be obtained. Failure to comply with the governing statutes or the implementing regulations may lead to the assessment of administrative, civil or criminal penalties. We believe that our salt dome storage operations, including the caverns, brine pits and brine disposal wells, are in substantial compliance with applicable statutes.

Safety regulation issues

Our NGL, petrochemical and gas pipelines are subject to the pipeline safety program established by the 1996 federal Pipeline Safety Act and its implementing regulations. The U.S. Department of Transportation, through the Office of Pipeline Safety (OPS), is responsible for developing, issuing and enforcing regulations relating to the design, construction, inspection, testing, operation, replacement and management of natural gas and hazardous liquid pipelines. In 2001 OPS issued safety regulations containing requirements for the development of integrity management programs for oil pipelines (which includes NGL and petrochemical pipelines such as ours) in certain high consequence areas . High consequence areas include but are not limited to high population areas, environmentally sensitive locations, and areas containing drinking water supplies. In connection with these regulations, we developed a Pipeline Integrity Management Program and, by the end of 2002, had identified the segments of our liquids pipelines that were located in such areas. The regulations stipulate that a pipeline company must assess the condition of its pipelines in such areas and perform any necessary repairs. We are required to evaluate at least 50% of our identified pipeline mileage in such high consequence areas by the end of 2004 with the balance completed before April 2008. After this initial testing is complete, the identified pipeline segments must be reassessed every five years thereafter.

On November 15, 2002, Congress passed the Pipeline Safety Improvement Act, which contains requirements for the development of integrity management programs on gas pipelines located in certain high consequence areas, and effective February 14, 2004, OPS adopted regulations to implement this statute. The new regulations require gas pipeline operators to develop by December 17, 2004, integrity management programs for gas transmission pipelines that could impact high consequence areas in the event of a failure. We anticipate that our implementation of the gas pipeline regulations will proceed on a timely basis.

During 2003, we spent approximately $10 million to comply with these new regulations, of which $4.5 million was expensed. During each of the years 2004 through 2008, our cash outlays for this program are expected to be in the range of $12 million to $23 million. At present, we expect that approximately 85% of these future expenditures will be recorded as operating expenses.

The workplaces associated with our company-operated processing, storage and pipeline facilities are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. We believe that our facilities are in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances.

In general, we expect expenditures associated with industry and regulatory safety standards (such as those described above) will increase in the future. Although such expenditures cannot be accurately estimated at this time, we believe that such expenditures will not have a significant effect on our operations.

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.

OUR SEC REPORTING

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.

SECTION 2 REVISED MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

We are a publicly traded limited partnership (NYSE symbol, EPD) that was formed in April 1998 to acquire, own, and operate all of the NGL processing and distribution assets of Enterprise Products Company, or EPCO. We conduct all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P., our Operating Partnership and its subsidiaries and joint ventures. Our general partner, Enterprise Products GP, LLC, owns a 2.0% interest in us. Unless the context requires otherwise, references to we, us, our or the Company are intended to mean the consolidated business and operations of Enterprise Products Partners L.P., which includes Enterprise Products Operating L.P. and its subsidiaries.

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 and Risk Factors* under Item 1 of this annual report for information regarding forward-looking statements made in this discussion and 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, including our relationship with Shell.

RECENT DEVELOPMENTS

On December 15, 2003, we and certain of our affiliates, El Paso Corporation and certain of its affiliates (El Paso), and GulfTerra Energy Partners, L.P. (GulfTerra) and certain of its affiliates entered into a series of agreements under which one of our wholly-owned subsidiaries and GulfTerra would merge, with GulfTerra surviving the merger and becoming wholly-owned by us. Formed in 1993, GulfTerra is a publicly traded limited partnership (NYSE symbol, GTM) that manages a balanced, diversified portfolio of interests and assets relating to the midstream energy sector. Prior to December 15, 2003, El Paso was majority owner of GulfTerra s general partner and owns a 31.8% limited partner interest in GulfTerra.

In general, GulfTerra s business lines include:

Ownership or interests in over 15,700 miles of natural gas pipeline systems. These pipeline systems include gathering systems onshore in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas and offshore in some of the most active drilling and development regions in the Gulf of Mexico. GulfTerra also owns interests in five natural gas processing and treating plants located in New Mexico, Texas and Colorado;

Ownership in over 1,000 miles of intrastate NGL gathering and transportation pipelines and four NGL fractionation plants located in Texas. GulfTerra also owns interests in three offshore oil pipeline systems, which extend over 340 miles, owns a 3.3 MMBbl propane storage and leaching business located in Mississippi and owns or leases NGL storage facilities in Louisiana and Texas with aggregate capacity of approximately 21.3 MMBbls;

Ownership in two salt dome natural gas storage facilities located in Mississippi that have a combined current working capacity of 13.5 Bcf. In addition, GulfTerra has the exclusive right to use a natural gas storage facility located in Wharton, Texas under an operating lease that expires in January 2008. This facility has a working gas capacity of 6.4 Bcf;

Interests in seven multi-purpose offshore hub platforms in the Gulf of Mexico that were specifically designed to be used as deepwater hubs and production handling and pipeline maintenance facilities; and

Interests in four oil and natural gas producing properties located in waters offshore Louisiana. Production is gathered, transported, and processed through GulfTerra s pipeline systems and platform facilities, and sold to various third parties and El Paso.

GulfTerra is one of the largest natural gas gatherers, based on miles of pipeline, in the prolific natural gas supply regions offshore in the Gulf of Mexico and onshore in Texas and in the San Juan Basin, which includes a significant portion of the four contiguous corners of Arizona, Colorado, New Mexico and Utah. These regions, especially the deepwater regions of the Gulf of Mexico, which is one of the United States fastest growing oil and natural gas producing regions, offer GulfTerra significant growth potential through the acquisition and construction of pipelines, platforms, processing and storage facilities and other energy infrastructure.

The proposed merger is a three-step process outlined as follows:

Step One. On December 15, 2003, we purchased a 50% membership interest in GulfTerra s general partner (GulfTerra Energy Company, L.L.C. or GulfTerra GP) for $425 million. This investment is accounted for using the equity method. This transaction is referred to as Step One of the proposed merger and will remain in effect even if the remainder of the proposed merger and post-merger transactions, which we refer to as Step Two and Three, do not occur.

Step Two. If all necessary regulatory and unitholder approvals are received and the other merger agreement conditions are either fulfilled or waived and the following steps are consummated, we will own 100% of the limited and general partner interests in GulfTerra. At that time, the proposed merger will be accounted for using the purchase method and GulfTerra will be a consolidated subsidiary of our company. Step Two of the proposed merger includes the following transactions:

El Paso s contribution to our General Partner of El Paso s remaining 50% interest in GulfTerra GP for a 50% interest in our General Partner, and the subsequent capital contribution by our General Partner of such 50% interest in GulfTerra GP to us (without increasing our General Partner s interest in our earnings or cash distributions).

Our purchase of 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units owned by El Paso for $500 million; and

The exchange of each remaining GulfTerra common unit for 1.81 Enterprise common units, resulting in the issuance of approximately 103 million Enterprise common units to GulfTerra unitholders.

Step Three. Immediately after Step Two is completed, we expect to acquire nine cryogenic natural gas processing plants, one natural gas gathering system, one natural gas treating plant, and a small natural gas liquids connecting pipeline from El Paso for $150 million. We refer to the assets that we will acquire from El Paso as the South Texas midstream assets.

Our preliminary estimate of the total consideration for Steps One, Two and Three we would pay or grant is approximately $3.9 billion. For a period of three years following the closing of the proposed merger, El Paso will provide support services to GulfTerra similar to those provided by El Paso prior to the closing of the merger. GulfTerra will reimburse El Paso for 110% of its direct costs of such services (excluding any overhead costs). El Paso will make transition support payments to us in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in 12 equal monthly installments for each such year. These transition support payments are included in our preliminary estimate of total consideration.

We are working to complete the merger as soon as possible. A number of conditions must be satisfied before we can complete the merger, including approval by the unitholders of both the Company and GulfTerra and the expiration or termination of applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1974. While we cannot predict if and when all of the conditions to the merger will be satisfied, we expect to complete the merger in the second half of 2004.

To review a copy of the merger agreement and related transaction documents, please read our Current Report on Form 8-K filed with the Securities and Exchange Commission on December 15, 2003.

Our Results of Operations

We have segregated our business activities into four distinct 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. Our segments are regularly evaluated by the CEO of our general partner in deciding how to allocate resources and in assessing performance.

We evaluate segment performance based on the non-GAAP financial measure of segment gross operating margin. Segment gross operating margin 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 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 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. 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.

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

	For Year Ended December 31,		
	2003	**2002**	**2001**
Revenues	$ 5,346,431	$ 3,584,783	$ 3,154,369
Operating costs and expenses	5,046,777	3,382,839	2,862,582
Selling, general and administrative costs	37,590	42,890	30,296
Equity in income (loss) of unconsolidated affiliates	(13,960)	35,253	25,358
Operating income	248,104	194,307	286,849

The following table reconciles consolidated operating income to our measurement of total segment gross operating margin for the periods indicated (dollars in thousands):

	For Year Ended December 31,		
	2003	**2002**	**2001**
Operating income	$ 248,104	$ 194,307	$ 286,849
Adjustments to reconcile operating income			
to total gross operating margin:			
Depreciation and amortization in operating costs and expenses	115,643	86,028	48,775
Retained lease expense, net in operating costs and expenses	9,094	9,125	10,414
Loss (gain) on sale of assets in operating costs and expenses	(16)	(1)	(390)
Selling, general and administrative costs	37,590	42,890	30,296
Total segment gross operating margin	$ 410,415	$ 332,349	$ 375,944

Our gross operating margin amounts by segment were as follows for the periods indicated (dollars in thousands):

	For Year Ended December 31,		
	2003	2002	2001
Gross operating margin by segment:			
Offshore Pipelines & Services	$ 5,561	$ 10,535	$ 8,311
Onshore Natural Gas Pipelines & Services	18,345	22,109	11,679
NGL Pipelines & Services	310,631	181,884	258,625
Petrochemical Services [(1)]	75,931	117,821	97,329
Other, non-segment [(2)]	(53)		
Total gross operating margin	$ 410,415	$ 332,349	$ 375,944

(1) Includes non-cash asset impairment charge of $22.5 million recorded during the third quarter of 2003.
(2) The Other non-segment category is presented for financial reporting purposes only to show the historical equity earnings we received from the general partner of GulfTerra. We acquired a 50% membership interest in the general partner of GulfTerra on December 15, 2003 in connection with Step One of our merger with GulfTerra.

Our significant pipeline throughput, plant 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,		
	2003 [(1)]	2002 [(1)]	2001 [(1)]
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtu/d)	433	500	566
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtu/d)	599	701	783
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	1,275	1,306	420
NGL fractionation volumes (MBPD)	227	235	204
Equity NGL production (MBPD)	56	73	63
Petrochemical Services, net:			
Butane isomerization volumes (MBPD)	77	84	80
Propylene fractionation volumes (MBPD)	57	55	31
Octane additive production volumes (MBPD)	4	5	5
Petrochemical transportation volumes (MBPD)	68	46	33
Total, net:			
NGL and petrochemical transportation volumes (MBPD)	1,343	1,352	453
Natural gas transportation volumes (BBtu/d)	1,032	1,201	1,349
Equivalent transportation volumes (MBPD) [(2)]	1,615	1,668	808

(1) Volumetric data shown above reflects net operating rates of the underlying assets for the periods in which we owned them.
(2) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equal to one barrel of NGLs.

Product and Commodity Price 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 2001:

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound	Indicative Gas Processing Gross Spread, $/gallon
	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(3)
2001										
1st Quarter	$ 7.05	$ 28.77	$ 0.49	$ 0.63	$ 0.70	$ 0.74	$ 0.74	$ 0.23	$ 0.17	$ (0.01)
2nd Quarter	$ 4.65	$ 27.86	$ 0.37	$ 0.50	$ 0.56	$ 0.66	$ 0.63	$ 0.19	$ 0.12	$ 0.08
3rd Quarter	$ 2.90	$ 26.64	$ 0.27	$ 0.41	$ 0.49	$ 0.49	$ 0.56	$ 0.16	$ 0.13	$ 0.14
4th Quarter	$ 2.43	$ 21.04	$ 0.21	$ 0.34	$ 0.40	$ 0.39	$ 0.44	$ 0.18	$ 0.13	$ 0.11
Average	$ 4.26	$ 26.07	$ 0.33	$ 0.47	$ 0.54	$ 0.57	$ 0.59	$ 0.19	$ 0.14	$ 0.08
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	$ 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	$ 5.38	$ 31.14	$ 0.40	$ 0.58	$ 0.68	$ 0.70	$ 0.74	$ 0.23	$ 0.18	$ 0.09

(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 representativeof 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 relativemeasure 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 that 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.

Year ended December 31, 2003 compared to 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.

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

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 BBtu/d during 2003 versus 500 BBtu/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.

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. Overall, natural gas throughput volumes were 599 BBtu/d during 2003 versus 701 BBtu/d during 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. 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 $310.6 million for 2003 versus $181.9 million for 2002.

Natural gas processing and related NGL marketing activities. Gross operating margin from natural gas processing increased $47.9 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 loss of $0.2 million.

Equity NGL production at our gas processing plants averaged 56 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. To meet the natural gas processing needs of Shell (our largest natural gas processing customer) in this challenging business environment, we renegotiated certain provisions of the 20-year Shell natural gas processing agreement during the first quarter of 2003.

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 (such as the Shell agreement referenced in the preceding paragraph), 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.

NGL pipelines and storage. Gross operating margin from NGL pipelines and storage increased $72.3 million period-to-period. Net pipeline throughput was 1,275 MBPD during 2003 and 1,306 MBPD for the 2002 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 $86.3 million for 2003 versus $89.3 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.

NGL fractionation. Gross operating margin from NGL fractionation improved $8.5 million year-to-year. Net NGL fractionation volumes decreased to 227 MBPD during 2003 from 235 MBPD during 2002. 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. 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. Net propylene transportation volumes were 53 MBPD for 2003 versus 46 MBPD during 2002.

Gross operating margin from butane isomerization increased $6.8 million year-to-year. Isomerization volumes were 77 MBPD during the 2003 period compared to 84 MBPD during the 2002 period. 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.

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. Net MTBE production from this facility decreased to 4

MBPD during 2003 from 5 MBPD 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.

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.

Year ended December 31, 2002 compared to year ended December 31, 2001

Revenues for 2002 increased $430.4 million over those for 2001. The increase is primarily due to the financial results of acquired businesses during 2002 such as the purchase of Mid-America and Seminole from Williams and propylene fractionation and NGL and petrochemical storage assets from Diamond-Koch. Costs and expenses increased $533.4 million year-to-year primarily due to the addition of costs and expenses of acquired businesses and an unfavorable change in results from our commodity hedging activities. Operating income decreased $93.1 million and gross operating margin decreased $43.6 million primarily as a result of such changes.

Offshore Pipelines & Services

Gross operating margin from our Offshore Pipelines & Services segment was $10.5 million for 2002 compared to $8.3 million for 2001. Overall, natural gas throughput volumes were 500 BBtu/d during 2002 versus 566 BBtu/d during 2001. The increase in gross operating margin is primarily due to a $4.8 million increase in equity earnings from Starfish related to the settlement of a rate case in 2002.

Onshore Natural Gas Pipelines & Services

Gross operating margin from our Onshore Natural Gas Pipelines & Services segment was $22.1 million for 2002 compared to $11.7 million for 2001. Overall, natural gas throughput volumes were 701 BBtu/d during 2002 versus 783 BBtu/d during 2001. The increase in gross operating margin was caused by the inclusion of a full year s results of operations from our Acadian subsidiary in 2002, whereas 2001 included only nine months. We acquired Acadian Gas in April 2001.

NGL Pipelines & Services

Gross operating margin from our NGL Pipelines & Services segment was $181.9 million for 2002 versus $258.6 million for 2001.

Natural gas processing and related NGL marketing activities. Gross operating margin from natural gas processing was a loss of $17.6 million for 2002 compared to income of $155.0 million for 2001. Of the $172.6 million change in gross operating margin, $152.6 million is due to a decrease in results from our commodity hedging activities. We recorded a loss of $51.3 million from these activities during 2002 versus income of $101.3 million during 2001.

Gross operating margin from NGL marketing activities benefited from unusually strong demand for propane and isobutane during early and mid-2001 which did not repeat during 2002. The year-to-year net decline in commodity hedging results and earnings from our NGL marketing activities was partially offset by a favorable decrease in NGL inventory valuation adjustments. In addition, gross operating margin from NGL marketing activities for 2001 includes $10.6 million in bad debt expense related to uncollectible amounts owed to us by Enron, which filed for bankruptcy in December 2001. Our equity NGL production was 73 MBPD during 2002 versus 63 MBPD during 2001. The 10 MBPD increase in equity NGL production rates is primarily due to improved gas processing conditions.

NGL pipelines and storage. Gross operating margin from NGL pipelines and storage increased $103.4 million year-to-year. Net pipeline throughput was 1,306 MBPD during 2002 and 420 MBPD for 2001. Our acquisition of the Mid-America and Seminole NGL pipelines in July 2002 accounted for $81.1 million of the improvement in segment gross operating margin and 843 MBPD of the increase in throughput rates. Gross operating margin from our Mont Belvieu storage businesses improved $17.9 million in 2002 primarily due to the acquisition of Diamond-Koch s storage business in January 2002.

NGL fractionation. Gross operating margin from NGL fractionation decreased $7.5 million year-to-year. NGL fractionation volumes increased to 235 MBPD during 2002 from 204 MBPD during 2001. The year-to-year decrease in NGL fractionation gross operating margin is primarily due to lower revenues from our Mont Belvieu NGL fractionation facility caused by strong competition at this industry hub, partially offset by the addition of earnings from the Toca-Western facility we acquired in June 2002. Of the 31 MBPD increase in NGL fractionation volumes, 14 MBPD is due to our purchase of an additional 12.5% interest in the Mont Belvieu facility and 9 MBPD is due to the acquisition of Toca-Western.

Petrochemical Services

Gross operating margin from our Petrochemical Services segment was $117.8 million for the 2002 period compared to $97.3 for the 2001 period. Gross operating margin from propylene fractionation increased $22.2 million year-to-year. We expanded our propylene fractionation business in February 2002 with the acquisition of Splitter III from Diamond-Koch, which contributed $24.7 million of gross operating margin during 2002. Net propylene fractionation volumes were 55 MBPD for 2002 compared to 31 MBPD during 2001. Splitter III accounted for 25 MBPD of the increase in volumes. Net propylene transportation volumes were 46 MBPD for 2002 versus 33 MBPD during 2001.

Gross operating margin from butane isomerization decreased $4.6 million year-to-year. Isomerization volumes increased to 84 MBPD during 2002 versus 80 MBPD during 2001. The positive effect of the higher isomerization volumes was offset by a decrease in isomerization revenues. Certain of our isomerization fees are indexed to historical natural gas prices (which were higher in 2001 relative to 2002).

Our equity earnings from octane enhancement were $8.6 million for 2002 compared to $5.7 million for 2001. The improvement is primarily due to increased MTBE production attributable to lower maintenance downtime. On a gross basis, BEF s MTBE production increased to 15 MBPD during 2002 compared to 14 MBPD during 2001.

Selling, general and administrative expenses

These expenses increased to $42.9 million during 2002 compared to $30.3 million during 2001. The increase is primarily due to the additional staff and resources needed to support our expansion activities resulting from acquisitions and other business development. The majority of the additional costs for 2002 are attributable to amounts we paid Williams for transition services associated with our acquisition of Mid-America and Seminole.

Interest expense

Interest expense increased to $101.6 million during 2002 compared to $52.5 million during 2001. The increase is primarily due to debt obligations we incurred as a result of business acquisitions and investments in inventory. Of the $49.1 million increase in interest expense, $21.4 million is attributable to the debt incurred to finance the Mid-America and Seminole acquisitions. In addition, income from our interest rate hedging activities (which is recorded as a reduction in interest expense) decreased $12.3 million in 2002 when compared to 2001. The change in interest rate hedging results is primarily due to certain elections by counterparties during 2001 to terminate interest rate hedging agreements.

General outlook for 2004

We expect our business to be affected by the following key trends and events during 2004. 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.

As noted earlier, 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. As the domestic economy began to strengthen during the third and fourth quarters of 2003, NGL demand by the ethylene industry increased, but remained below the five-year average for these products.

As we begin 2004, we are encouraged by further improvement in demand for NGLs by the ethylene industry. We have received indications from many of our largest NGL consuming customers that their operating rates and demand for NGLs should be greater in 2004 than 2003 based on the demand for their products and the prospects of a further strengthening in the domestic and global economies. If our expectations regarding demand for NGLs by the ethylene industry are met and natural gas prices remain stable, we should realize improved operating rates at many of our facilities and pipelines.

Our overall results of operations and financial position during 2004 will be affected by the timing and successful completion of our proposed merger with GulfTerra.

The assets of the proposed combined partnership would include over 30,000 miles of pipelines comprised of over 17,000 miles of natural gas pipelines, 13,000 miles of NGL pipelines and 340 miles of offshore Gulf of Mexico large capacity crude oil pipelines. The combined partnership s other logistical assets would also include ownership interests in 164 MMBbls of NGL storage capacity and 23 Bcf of natural gas storage capacity, seven offshore Gulf of Mexico hub platforms, and import and export terminals on the Houston Ship Channel. The combined partnership would also own interests in 19 fractionation plants with a net capacity 650 MBPD and 24 natural gas processing plants with a net capacity of 6.0 Bcf/d.

We believe the assets and businesses of these two partnerships are complementary. We believe the scale and business opportunities for the combined partnership would provide us with a number of avenues to create value for our unitholders and our producing and consuming customers.

We are working to complete the merger as soon as possible. A number of conditions must be satisfied before we can complete the merger, including approval by the unitholders of both Enterprise and GulfTerra and the expiration or termination of applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1974. While we cannot predict if and when all of the conditions to the merger will be satisfied, we expect to complete the merger in the second half of 2004. For additional information regarding the proposed merger, please read *Recent Developments* beginning on page 49.

As a result of our acquisition of a 50% interest in GulfTerra GP in December 2003, our equity earnings from this investment will increase earnings from the Pipelines segment and increase cash distributions from unconsolidated affiliates. This acquisition is Step One of our proposed merger with GulfTerra. For additional information regarding the proposed merger with GulfTerra, please read *Recent*

Developments. During February 2004, we received the first quarterly cash distribution from GulfTerra GP, which was approximately $10.6 million. Future distributions and earnings from GulfTerra GP will be dependent on the declared distribution rates and operating results of GulfTerra.

Earnings from our Octane Enhancement business will continue to be subject to MTBE sales margins until our iso-octane project is completed. Several states, including California, New York and Connecticut, implemented MTBE bans on January 1, 2004. Although these bans have weakened overall demand for MTBE, several MTBE suppliers exited the industry during 2003. The reduced supply for MTBE during 2004 should help to stabilize prices over the short-term while we work to convert the facility to iso-octane production.

We are currently in the process of modifying BEF s MTBE production facility to produce iso-octane, a motor gasoline octane enhancement additive derived from isobutane. We expect iso-octane demand by refiners to replace octane volume that is lost as a result of MTBE being eliminated as a motor gasoline blendstock. Our modification project is expected to be complete during the third quarter of 2004. The facility will continue to produce MTBE as market conditions warrant and will be capable of producing either MTBE or iso-octane once the plant modifications are complete. Our isomerization rates related to BEF will depend on the extent that MTBE and iso-octane are produced (both products use isobutane as a feedstock). For additional information regarding our Octane Enhancement business including regulatory and environmental matters, please read *The Company s Operations Octane Enhancement* included under Item 1 of this annual report.

OUR LIQUIDITY AND CAPITAL RESOURCES

General

Our primary cash requirements, in addition to normal operating expenses and debt service, are for capital expenditures (both sustaining and expansion-related), 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 including (either separately or in combination) 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. 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, 2003, we had approximately $2.1 billion in principal outstanding under various debt agreements. On that date, total borrowing capacity under our revolving commercial bank credit facilities was $500 million of which $315 million was unused. For additional information regarding our debt, please read *Our debt obligations.*

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 which generated $182.5 million of cash to us (including related capital contributions from our General Partner). In January 2003, we sold an additional 14,662,500 common units under this shelf registration which generated $258.1 million of cash to us (including related capital contributions from our General Partner). We used the cash generated by these equity offerings to reduce debt outstanding under our 364-Day Term Loan and for working capital purposes. Also, in January and February 2003, we issued Senior Notes C ($350 million principal amount) and Senior Notes D ($500 million principal amount), respectively. For information regarding our application of cash obtained through these debt offerings, please read *Our debt obligations.*

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). In June 2003, we sold 11,960,000 common units under this shelf registration statement, which generated $261.1 million of cash to us (including related capital contributions from our General Partner). We used the cash generated by this equity offering to reduce debt outstanding under our revolving credit facilities. As a result of meeting certain financial tests, the Subordination Period (as defined in our partnership agreement), with respect to our subordinated units, ended on August 1, 2003. With the expiration of the Subordination Period, we may prudently issue an unlimited number of units for general partnership purposes.

In July 2003, we filed a registration statement with the SEC covering our Distribution Reinvestment Plan (the DRP). The DRP 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. Currently, the registration statement covers the issuance of up to 5,000,000 common units under the DRP. As a result of reinvestment proceeds from our limited partners under the DRP, our General Partner will be required to make cash capital contributions to us in order to maintain its ownership interest. We expect to use the cash generated from this reinvestment program for general partnership purposes.

Initial reinvestments under the DRP occurred in August 2003. For all of 2003, we issued 2,883,803 common units in connection with the DRP and received proceeds of approximately $60.3 million. EPCO s reinvestment accounted for approximately $55.0 million of the $60.3 million reinvested during 2003. To support our growth objectives and financial flexibility, EPCO has announced that it expects to reinvest under the DRP an additional $140 million of its cash distributions from the first quarter of 2004 through the first quarter of 2005. As a result, we are preparing to increase the number of common units that can be issued under the DRP to approximately 15,000,000 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. Our General Partner 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.

If deemed necessary, we believe that additional financing arrangements can be obtained on reasonable terms. Furthermore, we believe that maintenance of our investment grade credit ratings combined with a 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.

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

	For Year Ended December 31,		
	2003	**2002**	**2001**
Net income	$ 104,546	$ 95,500	$ 242,178
Adjustments to reconcile net income to cash flows provided by			
(used for) operating activities before changes in operating accounts:			
Depreciation and amortization	128,434	94,925	51,903
Equity in income of unconsolidated affiliates	13,960	(35,253)	(25,358)
Distributions received from unconsolidated affiliates	31,882	57,662	45,054
Changes in fair market value of financial instruments	(29)	10,213	(5,697)
Other	25,024	14,059	12,391
Cash flow from operating activities before changes in operating accounts	$ 303,817	$ 237,106	$ 320,471
Net effect of changes in operating accounts	120,888	92,655	(37,143)
Operating activities cash flows	$ 424,705	$ 329,761	$ 283,328

Operating cash flows primarily reflect net income adjusted for depreciation and amortization, equity earnings and cash distributions from unconsolidated affiliates, fluctuations in the fair value of financial instruments and changes in operating accounts. The net effect of changes in operating accounts is generally the result of timing of sales and purchases near the end of each period. Cash flow from operations is primarily based on earnings from our business activities. As a result, these cash flows are exposed to certain risks. The products that we process, sell

or transport are principally used as feedstocks in petrochemical manufacturing, in the production of motor gasoline and as fuel for residential, agricultural and commercial heating. Reduced demand for our products or services by industrial customers, whether because of general economic conditions, reduced demand for the end products made with our products, increased competition from petroleum-based products 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 NGL and energy 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 *Cautionary Statement Regarding Forward-Looking Information and Risk Factors* included under Item 1 of this annual report.

Year ended December 31, 2003 compared to year ended December 31, 2002

Operating cash flows. Cash flow from operating activities was an inflow of $424.7 million during 2003 compared to an inflow of $329.8 million during 2002. As shown in the preceding table, cash flow before the net effect of changes in operating accounts was an inflow of $303.8 million during 2003 versus $237.1 million during 2002. 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 $66.7 million increase in this element of our cash flows is primarily due to:

- earnings from newly acquired businesses 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.

The $33.5 million increase in depreciation and amortization is primarily due to additional businesses acquired since the first quarter of 2002. The net effect of changes in operating accounts is generally the result of timing of cash receipts from sales and cash payments for inventory, 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.

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. Our financing activities were a cash inflow of $248.9 million during 2003 compared to an inflow of $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 our General Partner s related $7.8 million contribution to us. Our General Partner 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.

Year ended December 31, 2002 compared to year ended December 31, 2001

Operating cash flows. Cash flow from operating activities was an inflow of $329.8 million during 2002 compared to $283.3 million during 2001. As shown in the preceding table, cash flow before changes in operating accounts was an inflow of $237.1 million during 2002 versus $320.5 million during 2001. The $83.4 million year-to-year decrease in this element of our cash flows is primarily due to net hedging losses in 2002 versus net hedging income in 2001 offset by increased distributions from unconsolidated affiliates and earnings from businesses we acquired during 2002. The $43.0 million increase in depreciation and amortization is primarily due to businesses we acquired during 2002. Changes in operating accounts are generally the result of timing of cash receipts from sales and cash payments for inventory, 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.

Investing cash flows. During 2002, we used $1.7 billion in cash for investing activities compared to $491.2 million during 2001. Fiscal 2002 reflects $1.6 billion of business acquisitions including $1.2 billion paid to acquire Mid-America and Seminole and $368.7 million paid to acquire Diamond-Koch s Mont Belvieu, Texas propylene fractionation and NGL and petrochemical storage businesses. Fiscal 2001 includes $113.0 million paid to acquire equity interests in four Gulf of Mexico natural gas pipelines from El Paso and $225.7 million paid to acquire Acadian Gas from Shell. During 2002, our capital expenditures were $72.1 million compared to $149.9 million during 2001. The majority of capital expenditures made during both periods were for projects within our Pipelines segment.

Financing cash flows. Our financing activities generated $1.3 billion in cash inflows during 2002 compared to $279.5 million during 2001. Our net borrowings were $1.3 billion in 2002 versus $449.7 million in 2001. The increase in borrowings is primarily due to acquisitions, particularly the $1.2 billion paid for Mid-America and Seminole and the $239.0 million for Diamond-Koch s propylene fractionation business. The borrowing shown for 2001 reflects the issuance of our Senior Notes B, which was primarily used to finance the acquisition of Acadian Gas, Starfish, Neptune and Nemo.

Financing activities also reflect the net proceeds and related General Partner contributions from our October 2002 issuance of 9,800,000 new common units. Net proceeds from the sale of the common units were $182.5 million. This amount includes the General Partner s aggregate contribution to us and our Operating Partnership of $3.7 million to maintain its combined 2% general partner interest. Cash distributions to our partners and minority interests increased $52.2 million year-to-year primarily due to increases in both the declared quarterly distribution rates and the number of units eligible for distributions. The number of units eligible for distributions was higher in 2002 due to the conversion of 19.0 million of Shell s Class A special units to an equal number of common units in August 2002 and our issuance of the 9.8 million new common units in October 2002. Debt issuance costs increased $16.2 million year-to-year primarily due to the $15.0 million in fees we paid to lenders in July 2002 associated with the short-term financing of the Mid-America and Seminole acquisitions.

Our debt obligations

Our debt consisted of the following at the dates indicated:

	December 31,	
	2003	**2002**
Borrowings under:		
364-Day Term Loan, variable rate, repaid during 2003 [1]		$ 1,022,000
Interim Term Loan, variable rate, due the earlier of September 2004 or the date that our proposed merger with GulfTerra is completed	$ 225,000	
364-Day Revolving Credit Facility, variable rate, due October 2004, $230 million borrowing capacity	70,000	99,000
Multi-Year Revolving Credit Facility, variable rate, due November 2005, $270 million borrowing capacity [2]	115,000	225,000
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	350,000
Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 2005 [3]	30,000	45,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
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	
Senior Notes D, 6.875% fixed rate, due March 2033	500,000	
Total principal amount	2,144,000	2,245,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,531	1,774
Less unamortized discounts on Senior Notes A, B and D	(5,983)	(311)
Subtotal long-term debt	2,139,548	2,246,463
Less current maturities of debt [4]	(240,000)	(15,000)
Long-term debt [4]	$ 1,899,548	$ 2,231,463
Standby letters of credit outstanding, $75 million of credit capacity available under our Multi-Year Revolving Credit Facility [2]	$ 1,300	$ 2,400

(1) We used a combination of proceeds from the issuance of Senior Notes C and D and the October 2002 and January 2003 common unit offerings to fully repay this $1.2 billion facility in February 2003.

(2) This facility has $270 million of total borrowing capacity, which is reduced by the amount of standby letters of credit outstanding.

(3) As to the assets of our subsidiary, Seminole Pipeline Company, our $2.1 billion in senior indebtedness at December 31, 2003 is structurally subordinated and ranks junior in right of payment to the $30 million of indebtedness of Seminole Pipeline Company.

(4) 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, 2003 reflect the classification of such debt obligations at March 1, 2004. With respect to our 364-Day Revolving Credit Facility, borrowings under this facility are not included in current maturities because we have the option and ability to convert any revolving credit balance outstanding at maturity to a one-year term loan (due October 2005) in accordance with the terms of the agreement.

For scheduled future maturities of long-term debt at December 31, 2003, please read *Our contractual obligations.*

Parent-subsidiary guarantor relationships

We act as guarantor of all of our Operating Partnership s consolidated debt obligations, with the exception of the Seminole Notes. 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 78.4% of its capital stock).

General description of debt

The following is a summary of the significant aspects of our debt obligations at December 31, 2003.

Interim Term Loan. In December 2003, our Operating Partnership entered into a $225 million acquisition-related term loan to partially finance our $425 million purchase from El Paso of a 50% membership interest in GulfTerra GP. The maturity date of this term loan is the earlier of September 2004 or the date our proposed merger with GulfTerra is completed. The Operating Partnership s borrowings under this agreement are unsecured general obligations that are non-recourse to our General Partner. We have guaranteed repayment of amounts due under this term loan through an unsecured guarantee.

As defined by the agreement, variable interest rates charged under this facility generally bear interest at either, at our election, (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate. Whichever base rate we select, the rate is increased by an appropriate applicable margin (as defined in the loan agreement). For information regarding variable-interest rates paid under this term loan agreement, please read *Information regarding variable-interest rates paid.*

This term loan agreement contains various covenants related to our ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires us to satisfy certain financial covenants at the end of each fiscal quarter. If an event of default (as defined in the agreement) occurs, the Operating Partnership will be prohibited from making distributions to us, which would impair our ability to make distributions to our partners. As defined in the agreement, we must maintain a specified level of consolidated net worth and certain financial ratios. We were in compliance with these covenants at December 31, 2003.

364-Day Revolving Credit Facility. In October 2003, our Operating Partnership entered into new 364-day revolving credit agreement that contained essentially the same terms as our November 2002 364-Day revolving credit agreement that expired in November 2003. The stand-alone borrowing capacity under the new revolving credit facility is $230 million with the maturity date for any amount outstanding being October 2004. We have the option to convert any revolving credit balance outstanding at maturity to a one-year term loan (due October 2005) in accordance with the terms of the credit agreement. The Operating Partnership s borrowings under this agreement are unsecured general obligations that are non-recourse to our General Partner. We have guaranteed repayment of amounts due under this term loan through an unsecured guarantee.

As defined by the agreement, variable interest rates charged under this facility generally bear interest at either, at our election, (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate. Whichever base rate we select, the rate is increased by an appropriate applicable margin (as defined within the loan agreement). We elect the basis of the interest rate at the time of each borrowing. For information regarding variable-interest rates paid under this revolving credit agreement, please read *Information regarding variable-interest rates paid.*

This revolving credit agreement contains various covenants similar to those of our Interim Term Loan (please refer to our discussion regarding restrictive covenants of the Interim Term Loan within this *General description of debt* section). We were in compliance with these covenants at December 31, 2003.

Multi-Year Revolving Credit Facility. In November 2002, our Operating Partnership entered into a five-year revolving credit facility that includes a sublimit of $75 million for standby letters of credit. Currently, the stand-alone borrowing capacity under this revolving credit facility is $270 million. The Operating Partnership s borrowings under this agreement are unsecured general obligations that are non-recourse to our General Partner. We have guaranteed repayment of amounts due under this term loan through an unsecured guarantee.

As defined by the agreement, variable interest rates charged under this facility generally bear interest at either, at our election, (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate. We elect the basis of the interest rate at the time of each borrowing. For information regarding variable-interest rates paid under this revolving credit agreement, please read *Information regarding variable-interest rates paid.*

This revolving credit agreement contains various covenants similar to those of our Interim Term Loan (please refer to our discussion regarding restrictive covenants of the Interim Term Loan within this *General description of debt* section). We were in compliance with these covenants at December 31, 2003.

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 our General Partner. 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, 2003.

In January 2003, we issued $350 million in principal amount of 6.375% fixed-rate senior notes due February 2013 (Senior Notes C), from which we received net proceeds before offering expenses of approximately $347.7 million. These private placement notes were sold at face value with no discount or premium. We used the proceeds from this offering to repay a portion of the indebtedness outstanding under the 364-Day Term Loan that we incurred to finance the Mid-America and Seminole acquisitions. In May 2003, we exchanged 100% of the private placement Senior Notes C for publicly registered Senior Notes C.

In February 2003, we issued $500 million in principal amount of 6.875% fixed-rate senior notes due March 2033 (Senior Notes D), from which we received net proceeds before offering expenses of approximately $489.8 million. These private placement notes were sold at 98.842% of their face amount. We used $421.4 million from this offering to repay the remaining principal balance outstanding under the 364-Day Term Loan. In addition, we applied $60.0 million of the proceeds to reduce the balance outstanding under the 364-Day Revolving Credit Facility. The remaining proceeds were used for working capital purposes. In July 2003, we exchanged 100% of the private placement Senior Notes D for publicly registered Senior Notes D.

Repayment of 364-Day Term Loan

In July 2002, our Operating Partnership entered into the $1.2 billion senior unsecured 364-Day Term Loan to fund the acquisition of interests in the Mid-America and Seminole pipelines. We used $178.5 million of the $182.5 million in proceeds from our October 2002 equity offering to partially repay this loan. We also used $252.8 million of the $258.1 million in proceeds from the January 2003 equity offering, $347.0 million of the $347.7 million in proceeds from our issuance of Senior Notes C and $421.4 million in proceeds from our issuance of Senior Notes D to fully repay the 364-Day Term Loan in February 2003.

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 2003.

	Range of interest rates paid	Weighted-average interest rate paid
364-Day Term Loan (1)	2.59% - 2.88%	2.85%
364-Day Revolving Credit Facility	1.79% - 4.75%	2.48%
Multi-Year Revolving Credit Facility	1.64% - 4.25%	1.87%
Interim Term Loan	1.77% - 4.00%	2.16%

(1) This facility was fully repaid in February 2003.

Credit ratings

Our current senior unsecured credit ratings are Baa2 as rated by Moody s Investor Services and BBB- as rated by Standard and Poor s, both are investment grade. On December 15, 2003 as the result of our execution of definitive agreements with GulfTerra and El Paso to merge with GulfTerra, Moody s put our rating under review for possible downgrade and Standard and Poor s placed our rating on credit watch with negative implications. Both debt rating agencies will be reviewing the credit attributes and the risk profile of the merged partnership as well as the execution risk of the permanent financing of the proposed merger.

On November 26, 2003, our senior unsecured credit rating as rated by Standard and Poor s was lowered from BBB to BBB- with a negative outlook. Standard and Poor s indicated that the negative outlook reflected their concern that the rebound in NGL demand was temporary and that weak demand could return in 2004. Standard and Poor s also indicated that our rating was subject to downgrade if our financial performance in 2004 was less than the then current expectations. Standard and Poor s cited concerns regarding our financial performance during the second and third quarters of 2003 and the sustainability of increased NGL demand by the petrochemical industry during 2004. Standard and Poor s indicated that it was also evaluating what effect, if any, that EPCO s purchase of Shell s interest in our General Partner might have on our overall credit quality.

We believe that the maintenance of an investment grade credit rating is important in managing our liquidity and capital resource requirements. We maintain regular communications with these ratings agencies, each of which independently judges our creditworthiness based on a variety of quantitative and qualitative factors.

Capital spending forecasts

At December 31, 2003, we had $4.0 million in estimated outstanding purchase commitments attributable to capital projects, practically all of which were related to the construction of assets that will be recorded as property, plant and equipment. During 2004, we expect capital spending on internal growth projects to approximate $87 million, of which $42 million is projected to be spent on projects within our Pipelines segment and approximately $30 million on the conversion of the MTBE facility to dual use MTBE and iso-octane production. We expect to invest approximately $8 million in the projects of our unconsolidated affiliates during 2004, of which $6 million is attributable to projects of our Gulf of Mexico natural gas pipeline investments.

EPCO subleases to us all of the equipment it holds pursuant to operating leases relating to an isomerization unit, a deisobutanizer tower, a cogeneration unit and approximately 100 railcars for one dollar per year and has assigned to us its purchase option under such leases (the retained leases). EPCO remains liable for the lease payments associated with these items. We have notified the original lessor of the isomerization unit of our intent to exercise the purchase option assigned to us. Under the terms of the lease agreement for the isomerization unit, we have the option to purchase the equipment at the lesser of fair value or $23.1 million.

Pipeline Integrity Management Program

Our NGL, petrochemical and gas pipelines are subject to the pipeline safety program established by the 1996 federal Pipeline Safety Act and its implementing regulations. The U.S. Department of Transportation, through the Office of Pipeline Safety (OPS), is responsible for developing, issuing and enforcing regulations relating to the design, construction, inspection, testing, operation, replacement and management of natural gas and hazardous liquid pipelines. In 2001 OPS issued safety regulations containing requirements for the development of integrity management programs for oil pipelines (which includes NGL and petrochemical pipelines such as ours) in certain high consequence areas. High consequence areas include but are not limited to high population areas, environmentally sensitive locations, and areas containing drinking water supplies. In connection with these regulations, we developed a Pipeline Integrity Management Program and, by the end of 2002, had identified the segments of our liquids pipelines that were located in such areas. The regulations stipulate that a pipeline company must assess the condition of its pipelines in such areas and perform any necessary repairs. We are required to evaluate at least 50% of our identified pipeline mileage in such high consequence areas by the end of 2004 with the balance completed before April 2008. After this initial testing is complete, the identified pipeline segments must be reassessed every five years thereafter.

On November 15, 2002, Congress passed the Pipeline Safety Improvement Act, which contains requirements for the development of integrity management programs on gas pipelines located in certain high consequence areas, and effective February 14, 2004, OPS adopted regulations to implement this statute. The new regulations require gas pipeline operators to develop by December 17, 2004, integrity management programs for gas transmission pipelines that could impact high consequence areas in the event of a failure. We anticipate that our implementation of the gas pipeline regulations will proceed on a timely basis.

During 2003, we spent approximately $10 million to comply with these new regulations, of which $4.5 million was expensed. During each of the years 2004 through 2008, our cash outlays for this program are expected to be in the range of $12 million to $23 million. At present, we expect that approximately 85% of these future expenditures will be recorded as operating expenses.

OUR CONTRACTUAL OBLIGATIONS

The following table summarizes our contractual obligations at December 31, 2003 (dollars in thousands):

	Payment or Settlement due by Period				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Time period		(2004)	(2005 - 2006)	(2007 - 2008)	Beyond 2008
Long-term debt, including current maturities (1)	$2,144,000	$ 240,000	$550,000		$1,354,000
Operating lease obligations (2)	$ 47,197	$ 8,928	$ 8,076	$ 7,130	$ 23,063
Purchase obligations: (3)					
Product purchase commitments: (4)					
Estimated payment obligations:					
Natural gas	$1,079,876	$ 150,620	$233,466	$231,930	$ 463,860
NGLs	$ 131,904	$ 15,745	$ 17,870	$ 17,870	$ 80,419
Petrochemicals	$1,149,987	$ 425,971	$700,345	$ 23,671	
Other	$ 75,455	$ 45,996	$ 23,889	$ 4,414	$ 1,156
Underlying major volume commitments:					
Natural gas (in BBtus)	164,032	23,602	35,310	35,040	70,080
NGLs (in MBbls)	5,333	578	732	732	3,291
Petrochemicals (in MBbls)	36,892	13,696	22,442	754	
Service payment commitments (5)	$ 552	$ 382	$ 170		
Capital expenditure commitment (6)	$ 4,003	$ 4,003			
Other Long-term liabilities, as reflected on our Consolidated Balance Sheet (7)	$ 14,081	$ 860	$ 11,078		$ 2,143

(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 (including current maturities thereof) for the periods indicated. For additional information regarding our debt obligations, please read - *Our liquidity and capital resources Our debt obligations*.

(2) 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.

(3) 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.

(4) 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 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, 2003 applied to future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery.

(5) 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.

(6) 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.

(7) 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 joint venture audits, major maintenance accruals related to our MTBE facility, environmental liabilities and other amounts. Amounts shown in the table represent our best estimate as to the timing of payments.

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 $12.1 million in 2004, $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. We notified the lessor of the isomerization unit associated with the retained leases of our intent to exercise the purchase option relating to this equipment in 2004. Under the terms of the lease agreement for the isomerization unit, we have the option to purchase the equipment at the lesser of fair value or $23.1 million. Should we decide to exercise all of the remaining purchase options associated with the retained leases (which are at fair value), up to an additional $2.8 million would be payable in 2004, $2.3 million in 2008 and $3.1 million in 2016. For additional information regarding the retained leases, please read Item 13 of this annual report on Form 10-K.

RECENT ACCOUNTING DEVELOPMENTS

SFAS No. 143, Accounting for Asset Retirement Obligations. We adopted this standard as of January 1, 2003. This statement establishes accounting standards for the recognition and measurement of an asset retirement obligation (ARO) liability and the associated asset retirement cost. Our adoption of this standard had no material impact on our financial statements. For a discussion regarding our implementation of this new standard, please read Notes 1 and 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections. We adopted provisions of this standard as of January 1, 2003. This statement revised accounting guidance related to the extinguishment of debt and accounting for certain lease transactions. It also amended other accounting literature to clarify its meaning, applicability and to make various technical corrections. Our adoption of this standard has had no material impact on our financial statements.

SFAS No. 146, *Accounting for Costs Associated with Exit and Disposal Activities.* We adopted this standard as of January 1, 2003. This statement requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of an entity s commitment to an exit or disposal plan. Our adoption of this standard has had no material impact on our financial statements.

SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure. We adopted this standard as of December 31, 2002. This statement provides alternative methods of transition from a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123, *Accounting for Stock-Based Compensation*, in both annual and interim financial statements. We have provided the information required by this statement in Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. Apart from this additional footnote disclosure, our adoption of this standard has had no material impact on our financial statements.

SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. We adopted SFAS No. 149 on a prospective basis as of July 1, 2003. This statement amends and clarifies accounting guidance for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. This statement is effective for contracts entered into or modified after June 30, 2003, for hedging relationships designated after June 30, 2003, and to certain preexisting contracts. Our adoption of this standard has had no material impact on our financial statements.

SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity. We adopted this standard on July 1, 2003. This standard establishes classification and measurement standards for financial instruments with characteristics of both liabilities and equity. It requires an issuer of such financial instruments to reclassify the instrument from equity to a liability or an asset. Our adoption of this standard has had no material impact on our financial statements.

FIN 45, Guarantor s Accounting and Disclosure Requirement from Guarantees, Including Indirect Guarantees of Indebtedness of Others. We implemented this FASB interpretation as of December 31, 2002. This interpretation of SFAS No. 5, 57 and 107, and rescission of FASB Interpretation No. 34 elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. We have provided the information required by this interpretation in Note 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. Our implementation of this interpretation has had no material impact on our financial statements.

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 FIN46R) in 2003 has had no material effect on our financial statements.

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 the 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 should the underlying assumptions prove to be incorrect. The following describes the estimation risk in each of these significant financial statement items:

Depreciation methods and estimated useful lives of property, plant and equipment

Property, plant and equipment is recorded at cost and is depreciated using the straight-line method over the asset s estimated useful life. Our plants, pipelines and storage facilities have estimated useful lives of five to 35 years. Our miscellaneous transportation equipment have estimated useful lives of three to 10 years. Depreciation is the systematic and rational allocation of an asset s cost, less its residual value (if any), to the periods it benefits. Straight-line depreciation results in depreciation expense being incurred evenly over the life of the asset. The determination of an asset s estimated useful life must take a number of factors into consideration, including technological change, normal depreciation and actual physical usage. If any of these assumptions subsequently change, the estimated useful life of the asset could change and result in an increase or decrease in depreciation expense. At December 31, 2003 and 2002, the net book value of our property, plant and equipment was $3.0 billion and $2.8 billion, respectively. We recorded $101.0 million and $72.5 million in depreciation expense during 2003 and 2002, respectively. 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.

Impairment charges and underlying estimated fair values

If we determine that an asset s undepreciated cost may not be recoverable due to impairment of the asset, then we are required to take a charge against earnings. 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. An asset is 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 undiscounted 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. If we initially determine that an asset s carrying value is recoverable through such undiscounted estimated cash flows and later revise these assumptions and determine that the opposite is true, we would be required to ascertain the fair value of the facility, which might ultimately result in an impairment charge being recorded.

If the carrying value of an asset exceeds the sum of its undiscounted expected cash flows, an impairment loss equal to the amount that the carrying value exceeds the fair value of the asset is recognized. The quoted market price of an asset on an active exchange or similar venue is the best determinant of fair value. However, in many instances, quoted market prices in such markets are not available. In those instances, the estimate of fair value is based on the best information available, including prices for similar assets and the results of using other valuation techniques (including present value techniques).

Since most of our plant and other fixed and intangible assets are not traded in an active market, we generally rely on the use of present value techniques when determining the fair value of such assets for the purpose of impairment testing. These techniques incorporate our best available information and assumptions regarding future cash flows, alternative courses of action, probabilities of such courses of action occurring and discount rates. To the extent that any of these underlying assumptions prove incorrect, we may be required to take additional impairment charges in the future.

Due to a 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 BEF s long-lived assets exceeded their collective fair value, which resulted in a non-cash impairment charge of $67.5 million. Our share of this loss is $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 three and nine months ended September 30, 2003. Our historical equity (and in the future, consolidated) earnings from BEF are classified under the Petrochemical Services business segment. For additional information regarding this impairment charge, please read Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Amortization methods and estimated useful lives of qualifying intangible assets

The specific, identifiable intangible assets of a business enterprise depend largely upon the nature of its operations. Potential intangible assets include intellectual property such as technology, patents, trademarks and trade names, customer contracts and relationships, and non-compete agreements, as well as other intangible assets. The 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 contract-based assets representing the rights we own arising from contractual agreements. A contract-based intangible 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 the entity. It is based on an analysis of all pertinent factors including (1) the expected use of the asset by the entity, (2) the expected useful life of related assets (i.e., fractionation facility, storage well, etc.), (3) any legal, regulatory or contractual provisions, including renewal or extension periods that would not 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 the underlying assumption(s) governing the amortization of an intangible asset were later determined to have significantly changed (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. Such a change would increase or decrease the annual amortization charge associated with the asset at that time. During 2002, we did not find it necessary to adjust the estimated useful life or amortization period of any of our intangible assets.

Should any of the underlying assumptions indicate that the value of the intangible asset might be impaired, we may be required to reduce the carrying value and subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life (i.e., amortization period) of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2003 and 2002, the carrying value of our intangible asset portfolio was $268.9 million and $277.7 million, respectively. We did not recognize any impairment losses related to our intangible assets during 2003 or 2002. 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 the $73.6 million associated with the purchase of propylene fractionation assets from Diamond-Koch in February 2002. Since our adoption of SFAS No. 142, *Goodwill and Other Intangible Assets*, on January 1, 2002, our goodwill amounts are no longer amortized. Instead, goodwill is tested annually at a reporting unit level, and goodwill is tested more frequently if certain circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. If such indicators are present (i.e., loss of a significant customer, economic obsolescence of plant assets, etc.), then the fair value of the reporting unit, including its related goodwill, is calculated and compared to its combined book value. Currently, our goodwill is primarily recorded as part of the Petrochemical Services operating segment (based on the assets to which the goodwill relates).

If the fair value of the reporting unit exceeds its book value, then 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.

At December 31, 2003 and 2002, the carrying value of our goodwill was $82.4 million and $81.5 million, respectively. 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 investment in Dixie and GulfTerra GP exceeded our share of the historical cost of the underlying net assets of such entities (excess cost). The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. The excess cost of Dixie and GulfTerra includes amounts attributable to goodwill. 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 other than a temporary decline. For additional information regarding our excess cost amounts, please read Notes 1 and 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

For Dixie, the amount attributable to goodwill at December 31, 2003 was $9.2 million. For GulfTerra GP, the amount attributable to goodwill at December 31, 2003 was estimated at $328.2 million. The goodwill amount for GulfTerra GP represents our preliminary allocation of the purchase price pending completion of a fair value analysis which is expected to be completed during the second half of 2004. To the extent that our preliminary allocation of the excess cost of GulfTerra GP is ultimately attributed to depreciable or amortizable assets, our equity earnings from GulfTerra will be reduced from what it otherwise would be.

The table below shows the potential decrease in equity earnings from GulfTerra GP if certain amounts of the $328.2 million of excess cost preliminarily attributable to goodwill were ultimately assigned to fixed or intangible assets. For purposes of calculating this sensitivity, we have applied the straight-line method of cost allocation (i.e. depreciation or amortization) over an estimated useful life of 20-years to various fair values.

	Excess Cost attributed to tangible or intangible assets	**Estimated Annual Reduction in Equity Earnings**
20% of excess cost	$ 65,643	$ 3,282
40% of excess cost	131,286	6,564
60% of excess cost	196,928	9,846
80% of excess cost	262,571	13,129
100% of excess cost	328,214	16,411

Our revenue recognition policies

In general, we recognize revenue from our customers when all of the following criteria are met: (i) firm contracts are in place, (ii) delivery has occurred or services have been rendered, (iii) pricing is fixed and determinable and (iv) collectibility is reasonably assured. When contracts settle (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), we determine if an allowance is necessary and record it accordingly. Historically, the consolidated revenues we recorded were not materially based on estimates. However, as SEC regulations require us to submit financial information on increasingly accelerated timeframes, our use of estimates will increase. We believe the assumptions underlying any revenue estimates that we might use will not prove to be materially different from actual amounts due to our development and implementation of a fully integrated volume management system that is inclusive of operational activities through financial accounting.

For additional information regarding our revenue recognition policies, please read Note 3 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Mark-to-market accounting for certain financial instruments

Our earnings are also affected by use of the mark-to-market method of accounting for certain financial instruments. We use short-term, highly liquid financial instruments such as swaps, forwards and other contracts to manage price risks associated with inventories, firm commitments and certain anticipated transactions, primarily within our NGL Pipelines & Services segment. The use of mark-to-market accounting for financial instruments may cause our non-cash earnings to fluctuate based upon changes in underlying indexes, primarily those related to commodity prices. Fair value for the financial instruments we employ is determined using price data from highly liquid markets such as the NYMEX commodity exchange.

During 2002, we recognized a loss of $51.3 million from our commodity hedging activities. Of this loss, $5.6 million was attributable to the change in fair value of the portfolio between December 31, 2001 and December 31, 2002. In March 2002, the effectiveness of our primary commodity hedging strategy deteriorated due to an unexpected rapid increase in natural gas prices; therefore, the loss in value of our fixed-price natural gas financial instruments was not offset by increased gas processing margins. We exited the strategy underlying this loss in 2002.

During 2003, we utilized a limited number of commodity financial instruments from which we recorded a loss of $0.6 million. The fair value of open positions at December 31, 2003 was a nominal receivable amount. For additional information regarding our commodity financial instruments, please read Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

For additional information regarding our use of financial instruments to manage risk and the earnings sensitivity of these instruments to changes in underlying commodity prices, please read the Processing segment discussions under *Our results of operations* and also read Item 7A of this annual report.

Additional information regarding our financial statements can be found in our Notes to Consolidated Financial Statements included under Item 8 of this annual report.

RELATED PARTY TRANSACTIONS

Relationship with EPCO and its affiliates

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director (and Chairman of the Board of Directors) of our General Partner. In addition, the remaining executive and other officers of our General Partner are employees of EPCO, including O.S. Andras who is our Chief Executive Officer and a director of the General Partner. For a listing of our directors and executive officers, please read Item 10 of this annual report.

Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to the common units and Class B special units held by 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, EPCO and Dan Duncan LLC, together, own 100% of our General Partner, which in turn owns a 2% general partner interest in us. In addition, trust affiliates of EPCO (the 1998 Trust and 2000 Trust) owned 4,478,236 of our common units at February 20, 2004. Collectively, EPCO, Dan L. Duncan, the 1998 Trust and the 2000 Trust owned 54.6% of our partnership interests at February 20, 2004.

The principal business activity of the General Partner 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 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 buy from and sell NGL products to EPCO s Canadian affiliate. During 2003, our related party revenues from EPCO were $4.2 million and our related party expenses with EPCO were $177.6 million.

For additional information regarding our relationship with EPCO, please read Item 13 of this annual report.

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At February 20, 2004, Shell owned approximately 18.3% of our partnership interests.

Our largest customer is Shell. For the year ended December 31, 2003, Shell accounted for 5.5% 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 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. During 2003, our related party revenues from Shell were $293.1 million and our related party expenses with Shell were $607.3 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. 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 Item 13 of this annual report.

We have completed a number of business acquisitions and asset purchases involving Shell since 1999. Among these transactions were:

- the acquisition of TNGL s natural gas processing and related businesses in 1999 for approximately $528.8 million (this purchase price includes both the $166 million in cash we paid to Shell and the value of the 41,000,000 Class A special units granted to Shell in connection with this acquisition);
- the purchase of the Lou-Tex Propylene pipeline for $100 million in 2000; and
- the acquisition of Acadian Gas in 2001 for $243.7 million.

Shell is also a partner with us in our Gulf of Mexico natural gas pipeline investments. We also lease from Shell its 45.4% interest in our Splitter I propylene fractionation facility.

For additional information regarding our relationship with Shell, please read Item 13 of this annual report.

OTHER ITEMS

Uncertainties regarding our investment in facilities that produce MTBE

We have a 66.7% ownership interest in BEF, which owns a facility currently producing MTBE. At December 31, 2003, the value of our underlying equity in BEF was $49.2 million. The production of MTBE is 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.

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 BEF. It is possible, however, that MTBE manufacturers such as BEF could ultimately be added as defendants in such lawsuits or in new lawsuits. While we believe that we currently have adequate insurance to cover any adverse consequences resulting from our production of MTBE, we have been informed by our insurance carrier that upon renewal of our policy in April 2004, MTBE related claims may be excluded from the scope of our insurance coverage. For additional information regarding the impact of environmental regulation on BEF, please read *Business and Properties Regulation and Environmental Matters Impact of the Clean Air Act s oxygenated fuels programs on our BEF investment* included under Items 1 and 2 of this annual report.

As a result of these developments, we are currently 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. The modification project is expected to be completed during the third quarter of 2004 at a total cost of approximately $30 million. The facility will continue to produce MTBE as market conditions warrant and will be capable of producing either MTBE or iso-octane once the plant modifications are complete. Depending on the outcome of various factors (including pending federal legislation) the facility may be further modified in the future to produce alkylate.

Conversion of EPCO Subordinated Units to Common Units

On May 1, 2003, 10,704,936 of EPCO s subordinated units converted to common units as a result of our satisfying certain financial tests. The remaining 21,409,872 subordinated units converted to common units on August 1, 2003. These conversions have no impact upon our earnings per unit or distributions since subordinated units are already included in both the basic and fully diluted earnings per unit calculations and are distribution bearing.

Conversion of Shell Special Units to Common Units

On August 1, 2003, the last 10,000,000 of Shell s non-distribution bearing special units converted to common units. The conversion impacted basic earnings per unit beginning in the third quarter of 2003. These units were already included in our fully diluted earnings per unit computations. Since common units are distribution bearing, our limited partner cash distributions to Shell increased beginning with the distribution we made in November 2003.

Facility and sensitive infrastructure security matters

Following the 2001 terrorist attacks in the United States, we instituted a review of security measures and practices and emergency response capabilities for all facilities and sensitive infrastructure. In connection with this activity, we have participated in security coordination efforts with law enforcement and public safety authorities, industry mutual-aid groups and regulatory agencies. As a result of these steps, we believe that our security measures, techniques and equipment have been enhanced as appropriate on a location-by-location basis. Further evaluation will be ongoing, with additional measures to be taken as specific governmental alerts, additional information about improving security and new facts come to our attention.

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, primarily within our NGL Pipelines & Services segment. In general, the types of risks we attempt to hedge are those relating to the variability of future earnings and cash flows caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes. For additional information regarding our financial instruments, please read Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Commodity price risk

The prices of natural gas, NGLs, petrochemical products and MTBE 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 our NGL Pipelines & Services segment 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 certain anticipated transactions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

We do not hedge our exposure related to MTBE price risks. In addition, we generally do not hedge risks associated with the petrochemical marketing activities that are part of our Petrochemical Services segment. In our Onshore Natural Gas Pipelines & Services segment, we utilize a limited number of commodity financial instruments to manage the price Acadian Gas charges certain of its customers for natural gas. Lastly, due to the nature of the transactions, we do not employ commodity financial instruments in our fee-based marketing business accounted for in the NGL Pipelines & Services segment.

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 our General Partner. We 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. The General Partner oversees our 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.

Our commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, because of ineffectiveness. A financial instrument is generally regarded as effective when changes in its fair value almost fully offset changes in the fair value of the hedged item throughout the term of the instrument. Due to the complex nature of risks we attempt to hedge, our commodity financial instruments have generally not qualified as effective hedges under SFAS No. 133, with the result being that changes in the fair value of these positions being recorded on the balance sheet and in earnings through mark-to-market accounting. Mark-to-market accounting results in a degree of non-cash earnings volatility that is dependent upon changes in the commodity prices underlying these financial instruments. Even though these financial instruments may not qualify for hedge accounting treatment under SFAS No. 133, we view such contracts as hedges since this was the intent when we entered into such positions. Upon entering into such positions, our expectation is that the economic performance of these instruments will mitigate (or offset) the commodity risk being addressed. The specific accounting for these contracts, however, is consistent with the requirements of SFAS No. 133.

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 employ regression analysis techniques possessing 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.

The following table shows the effect of hypothetical price movements on the fair value (FV) of our commodity financial instrument portfolio and the related potential impact on our earnings (IE) at the dates indicated (dollars in thousands):

Scenario	Resulting classification	At 12/31/02	At 12/31/03	At 02/20/04
FV assuming no change in quoted market prices	Asset (Liability)	$ (26)	$ 4	$ 2
FV assuming 10% increase in quoted market prices	Asset (Liability)	$ (26)	$ 4	$ 2
IE assuming 10% increase in quoted market prices	Income (Loss)	$ -	$ -	$ -
FV assuming 10% decrease in quoted market prices	Asset (Liability)	$ (26)	$ 4	$ 2
IE assuming 10% decrease in quoted market prices	Income (Loss)	$ -	$ -	$ -

During 2003, we recognized a loss of $0.6 million from our commodity hedging activities that was recorded as an increase in our operating costs and expenses in the Statements of Consolidated Operations. Of the loss recognized in 2003, $0.8 million is related to commodity hedging activities associated with natural gas purchases within the Pipeline segment offset by a $0.2 million gain from commodity hedging activities associated with the hedging of NGL production within the NGL Pipelines & Services segment.

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 in the Statements of Consolidated Operations. Of the loss recognized in 2002, $5.6 million was related to non-cash mark-to-market income recorded on open positions at December 31, 2001. Due to commodity hedging losses we incurred during the first quarter of 2002, we exited most of our positions. For additional information regarding our NGL Pipelines & Services segment s results for 2002, please read *Management s Discussion and Analysis of Financial Condition and Results of Operations Our results of operations Year ended December 31, 2003 compared to year ended December 31, 2002* included under Item 7 of this annual report. At end of 2003 and 2002, we had a limited number of commodity financial instruments outstanding. The fair value of the portfolio at February 20, 2004 was a nominal asset amount and was again comprised of a limited number of positions.

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.

Interest rate risk

Our interest rate exposure results from variable-interest rate borrowings and fixed-interest rate borrowings. 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 to estimate the expected impact of changes in interest rates on our future cash flows. The General Partner oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

Interest rate swaps. At December 31, 2002, we had one interest rate swap outstanding having a notional amount of $54 million that was terminated on March 1, 2003 at the election of the counterparty. Upon the termination, we received $1.6 million associated with the final settlement of this swap. The fair value of this swap at December 31, 2002 was $1.6 million. There was no earnings impact from the termination of this swap.

On January 8, 2004, we entered into three interest rate swaps under which we agreed to pay variable rates of interest to mitigate the changes in fair value of fixed rate debt as shown below:

Hedged Fixed-Rate Debt	Effective Date	Termination Date	Notional Amount
Senior Notes D, 7.50% fixed-rate	1/12/04	2/01/2011	$50 Million
Senior Notes C, 6.375% fixed-rate	1/12/04	2/01/2013	$100 Million
Senior Notes C, 6.375% fixed-rate	1/12/04	2/01/2013	$100 Million

We have designated these swaps as fair value hedges. The swap agreements have a combine notional amount of $250 million and match the maturity of the underlying debt being hedged. Under the swap agreements, we pay to the counterparty a floating LIBOR-based interest rate (plus an applicable margin) and receive back from the counterparty a fixed-rate payment equivalent to rate being charged us under the debt being hedged, all based on the notional amounts stated in each swap agreement.

The following table shows the effect of hypothetical price movements on the fair value (FV) of our interest rate swap portfolio and potential change in the fair value of the debt. Income is not affected by changes in the fair value of the swap. However, the swap effectively converted the hedged portion of the fixed rate debt to a floating rate debt. Therefore, interest expense (and related cash flow) will increase or decrease with the change in the periodic reset rate associated with the respective interest rate swaps. The reset rate is the agreed upon index rate published for the first day of the six-month interest calculation period.

Scenario	Resulting Classification	At 2/20/04	Change in Fair Value of Debt
FV assuming no change in underlying interest rates	Asset (Liability)	$ 978	$ -
FV assuming 10% increase in underlying interest rates	Asset (Liability)	$(7,831)	$(8,809)
FV assuming 10% decrease in underlying interest rates	Asset (Liability)	$ 9,787	$ 8,809

Treasury Locks. During the fourth quarter of 2002, we entered into seven treasury lock transactions with original maturities of either January 31, 2003 or April 15, 2003. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific U.S. treasury security for an established period of time. The purpose of these transactions was to hedge the underlying treasury interest rate associated with our anticipated issuance of debt in early 2003 to partially refinance the Mid-America and Seminole acquisitions. Our treasury lock transactions were accounted for as cash flow hedges under SFAS No. 133. The notional amounts of these transactions totaled $550 million, with a total treasury lock rate of approximately 4%.

We elected to settle all of the treasury locks in early February 2003 in connection with our issuance of Senior Notes C and D. For additional information regarding Senior Notes C and D, please read *Management s Discussion and Analysis of Financial Condition and Results of Operations Our liquidity and capital resource Our debt obligations* included under Item 7 of this annual report. The settlement of the treasury locks resulted in our receipt of $5.4 million of cash. The $5.4 million is being amortized into income as a reduction of interest expense over a 10-year period. The amortization period is based on the terms of the anticipated transaction as required by SFAS No. 133.

The fair value of these instruments at December 31, 2002 was a current liability of $3.8 million offset by a current asset of $0.2 million. The $3.6 million net liability was recorded as a component of comprehensive income on that date, with no impact to current earnings. With the settlement of the treasury locks, the $3.6 million net liability was reclassified out of accumulated other comprehensive income in Partners Equity to offset the current asset and liabilities we recorded at December 31, 2002, with no impact to earnings. For additional information regarding our treasury lock transactions, see Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

SECTION 3 REVISED AUDITED CONSOLIDATED FINANCIAL STATEMENTS
Item 8. Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC
(the General Partner of EnterpriseProducts Partners L.P.):

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the Company) as of December 31, 2003 and 2002, and the related 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, 2003. Our audits also included the consolidated financial statement schedule of the Company included on page 137. These consolidated financial statements and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements and 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 consolidated financial position of the Company at December 31, 2003 and 2002, and the results of its consolidated operations and its consolidated cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

The Company changed its method of accounting for goodwill in 2002 and for derivative financial instruments in 2001. These changes are discussed in Notes 8 and 1, respectively, to the consolidated financial statements.

/s/ Deloitte & Touche LLP
Houston, Texas
March 9, 2004
(November 9, 2004 as to Note 20 for the change in reportable segments)

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

	December 31, 2003	December 31, 2002
ASSETS		
Current Assets		
Cash and cash equivalents (includes restricted cash of $13,851 at December 31, 2003 and $8,751 at December 31, 2002)	$ 44,317	$ 22,568
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $20,423 at December 31, 2003 and $21,196 at December 31, 2002	462,198	399,187
Accounts receivable - affiliates	347	228
Inventories	150,161	167,369
Prepaid and other current assets	30,160	48,216
Total current assets	687,183	637,568
Property, Plant and Equipment, Net	2,963,505	2,810,839
Investments in and Advances to Unconsolidated Affiliates	767,759	396,993
Intangible Assets, net of accumulated amortization of $40,371 at December 31, 2003 and $25,546 at December 31, 2002	268,893	277,661
Goodwill	82,427	81,547
Deferred Tax Asset	10,437	15,846
Long-Term Receivables	5,454	
Other Assets	17,156	9,818
Total	$ 4,802,814	$ 4,230,272
LIABILITIES AND PARTNERS EQUITY		
Current Liabilities		
Current maturities of debt	$ 240,000	$ 15,000
Accounts payable - trade	68,384	67,283
Accounts payable - affiliates	38,045	40,772
Accrued gas payables	622,982	489,562
Accrued expenses	24,695	35,760
Accrued interest	45,350	30,338
Other current liabilities	57,420	42,641
Total current liabilities	1,096,876	721,356
Long-Term Debt	1,899,548	2,231,463
Other Long-Term Liabilities	14,081	7,666
Minority Interest	86,356	68,883
Commitments and Contingencies		
Partners Equity		
Common units (213,366,760 units outstanding at December 31, 2003 and 141,694,766 at December 31, 2002)	1,582,951	949,835
Subordinated units (32,114,804 units outstanding at December 31, 2002)		116,288
Class A special units (10,000,000 units outstanding at December 31, 2002)		143,926
Class B special units (4,413,549 units outstanding at December 31, 2003)	100,182	
Treasury units acquired by Trust, at cost (798,313 units outstanding at December 31, 2003 and 859,200 Units at December 31, 2002)	(16,519)	(17,808)
General Partner	34,349	12,223
Accumulated Other Comprehensive Income (Loss)	4,990	(3,560)
Total Partners Equity	1,705,953	1,200,904

	December 31,	
Total	$ 4,802,814	$ 4,230,272

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,		
	2003	**2002**	**2001**
REVENUES			
Third parties	$ 4,782,206	$ 3,102,066	$ 2,641,913
Related parties	564,225	482,717	512,456
Total revenues	5,346,431	3,584,783	3,154,369
COST AND EXPENSES			
Operating costs and expenses			
Third parties	4,246,229	2,687,260	2,053,148
Related parties	800,548	695,579	809,434
Total operating costs and expenses	5,046,777	3,382,839	2,862,582
Selling, general and administrative			
Third parties	10,463	18,686	10,347
Related parties	27,127	24,204	19,949
Total selling, general and administrative costs	37,590	42,890	30,296
Total costs and expenses	5,084,367	3,425,729	2,892,878
EQUITY IN INCOME (LOSS) OF UNCONSOLIDATED AFFILIATES	(13,960)	35,253	25,358
OPERATING INCOME	248,104	194,307	286,849
OTHER INCOME (EXPENSE)			
Interest expense	(140,806)	(101,580)	(52,456)
Dividend income from cost method unconsolidated affiliates	5,595	4,737	3,462
Interest income - other	772	2,313	7,029
Other, net	33	304	(234)
Total other income (expense)	(134,406)	(94,226)	(42,199)
INCOME BEFORE PROVISION FOR INCOME TAXES AND MINORITY INTEREST	113,698	100,081	244,650
PROVISION FOR INCOME TAXES	(5,293)	(1,634)	
INCOME BEFORE MINORITY INTEREST	108,405	98,447	244,650
MINORITY INTEREST	(3,859)	(2,947)	(2,472)
NET INCOME	104,546	95,500	242,178
Cumulative transition adjustment related to financial instruments recorded upon adoption of SFAS No. 133 (see Note 18)			(42,190)
Reclassification of cumulative transition adjustment to earnings			42,190
Cash flow hedges	5,354	(3,560)	
Reclassification of cash flow hedges	3,196		

	For Year Ended December 31,		
COMPREHENSIVE INCOME	$ 113,096	$ 91,940	$ 242,178

See Notes to Consolidated Financial Statements

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,		
	2003	**2002**	**2001**
ALLOCATION OF NET INCOME TO:			
Limited partners	$ 83,817	$ 84,837	$ 236,570
General partner	$ 20,729	$ 10,663	$ 5,608
BASIC EARNINGS PER UNIT			
Net income per common, subordinated and Class B unit	$ 0.42	$ 0.55	$ 1.70
DILUTED EARNINGS PER UNIT			
Net income per common, subordinated, Class A and Class B unit	$ 0.41	$ 0.48	$ 1.39

See Notes to Consolidated Financial Statements

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

	For Year Ended December 31,		
	2003	**2002**	**2001**
OPERATING ACTIVITIES			
Net income	$ 104,546	$ 95,500	$ 242,178
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:			
Depreciation and amortization in operating costs and expenses	115,643	86,028	48,775
Depreciation in selling, general and administrative costs	158	78	2,341
Amortization in interest expense	12,634	8,819	787
Provision for impairment of long-lived asset value	1,200		
Equity in loss (income) of unconsolidated affiliates	13,960	(35,253)	(25,358)
Distributions received from unconsolidated affiliates	31,882	57,662	45,054
Operating lease expense paid by EPCO	9,010	9,033	10,309
Other expenses paid by EPCO	436		
Minority interest	3,859	2,947	2,472
Gain on sale of assets	(16)	(1)	(390)
Deferred income tax expense	10,534	2,080	
Changes in fair market value of financial instruments	(29)	10,213	(5,697)
Net effect of changes in operating accounts	120,888	92,655	(37,143)
Operating activities cash flows	424,705	329,761	283,328
INVESTING ACTIVITIES			
Capital expenditures	(145,913)	(72,135)	(149,896)
Proceeds from sale of assets	212	165	568
Business combinations, net of cash received	(37,348)	(1,620,727)	(225,665)
Acquisition of intangible asset	(2,000)	(2,000)	
Investments in and advances to unconsolidated affiliates	(471,927)	(13,651)	(116,220)
Investing activities cash flows	(656,976)	(1,708,348)	(491,213)
FINANCING ACTIVITIES			
Borrowings under debt agreements	1,926,210	1,968,000	449,717
Repayments of debt	(2,033,000)	(637,000)	
Debt issuance costs	(8,833)	(19,329)	(3,125)
Distributions paid to partners	(309,918)	(214,869)	(164,308)
Distributions paid to minority interests	(8,113)	(3,324)	(1,687)
Contributions from minority interests	5,949	1,976	105
Proceeds from issuance of common units	573,684	180,666	
Proceeds from issuance of Class B special units	102,041		
Treasury Units purchased		(12,788)	(18,003)
Treasury Units reissued	646		22,600
Settlement of treasury lock financial instruments	5,354		
Increase in restricted cash	(5,100)	(2,999)	(5,752)
Financing activities cash flows	248,920	1,260,333	279,547
NET CHANGE IN CASH AND CASH EQUIVALENTS	16,649	(118,254)	71,662
CASH AND CASH EQUIVALENTS, JANUARY 1	13,817	132,071	60,409
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 30,466	$ 13,817	$ 132,071

For Year Ended December 31,

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED PARTNERS EQUITY
(Dollars in thousands, see Note 10 for unit history)

	Limited Partners							
	Common units	**Subord. units**	**Class A Special units**	**Class B Special units**	**Treasury units**	**General Partner**	**Accum. OCI**	**Total**
Balance, January 1, 2001	$ 514,896	$ 165,253	$ 251,132		$ (4,727)	$ 9,405		$ 935,959
Net income	163,795	72,775				5,608		242,178
Operating leases paid by EPCO	7,078	3,128				103		10,309
Cash distributions to partners	(109,969)	(49,510)				(4,829)		(164,308)
Class A special units issued to Shell under contingency agreement			117,066			1,183		118,249
Conversion of 10 million Class A special units to common units	72,554		(72,554)					
Treasury unit transactions:								
- Purchased					(18,003)			(18,003)
- Reissued and sold					16,508			16,508
- Gain on reissued treasury units	3,518	1,461	990			61		6,030
Cumulative transition adjustment recorded per SFAS No. 133							$ (42,190)	(42,190)
Reclassification of cumulative transition adjustment to earnings							42,190	42,190
Balance, December 31, 2001	$ 651,872	$ 193,107	$ 296,634		$ (6,222)	$ 11,531	$ -	$ 1,146,922
Net income	69,636	15,201				10,663		95,500
Operating leases paid by EPCO	6,872	2,071				90		9,033
Cash distributions to partners	(153,449)	(49,564)				(11,856)		(214,869)
Conversion of 19 million Class A special units to common units	152,708		(152,708)					
Conversion of 10.7 million subordinated units to commonunits	44,265	(44,265)						
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	(928)	(262)			1,202	(12)		
Change in fair value of financial instruments recorded as cash flow hedges							(3,560)	(3,560)
Balance, December 31, 2002	$ 949,835	$ 116,288	$ 143,926		$ (17,808)	$ 12,223	$ (3,560)	$ 1,200,904

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED PARTNERS EQUITY (Continued)
(Dollars in thousands, see Note 10 for unit history)

	Limited Partners							
	Common units	**Subord. units**	**Class A Special units**	**Class B Special units**	**Treasury units**	**General Partner**	**Accum. OCI**	**Total**
Balance, December 31, 2002	$ 949,835	$ 116,288	$ 143,926		$ (17,808)	$ 12,223	$ (3,560)	$ 1,200,904
Net income	73,075	10,566		$ 176		20,729		104,546
Operating leases paid by EPCO	8,154	751		8		97		9,010
Other expenses paid by EPCO	435			(2)		3		436
Cash distributions to partners	(254,111)	(30,482)				(22,573)		(307,166)
Cash distributions related to unit options (see Note 15)	(2,721)					(31)		(2,752)
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 (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 General Partner ownership in our Operating Partnership (see Note 10)	(73)					16,127		16,054
Treasury unit transactions:								
- Reissued to satisfy unit options					640			640
- Gain on reissued treasury units	6							6
- Retired	(643)				649	(6)		
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	$ 1,582,951	$ -	$ -	$ 100,182	$ (16,519)	$ 34,349	$ 4,990	$ 1,705,953

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. including its consolidated subsidiaries is a publicly traded Delaware limited partnership listed on the NYSE symbol EPD . Unless the context requires otherwise, references to we, us, our or Enterprise are intended to mean the consolidated business and operations of Enterprise Products Partners L.P.

We were formed in April 1998 to own and operate certain NGL-related businesses of EPCO. We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P. (i.e., the Operating Partnership). We are owned 98% by our limited partners and 2% by our General Partner. We and our General Partner are affiliates of EPCO.

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.

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 in circumstances include continuing operating losses of the investee or long-term negative changes in the investee s industry. In the event that we determine that the loss in value of an investment is other than a temporary decline, we would record a charge to earnings to adjust the carrying value to fair value. We had no such impairment charges during 2002 or 2001; however, BEF recorded a $67.5 million asset impairment charge during 2003. Our share of this charge was $22.5 million which was recorded as a reduction in the equity earnings from BEF. See Note 7 for additional information regarding this asset impairment charge.

Certain reclassifications have been made to the prior years financial statements to conform to the current year presentation. These reclassifications had no effect on previously reported net income or earnings per unit.

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.

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 would 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 would 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 implementation of this standard.

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.

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 best 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, accrued environmental liabilities and expenditures to mitigate or eliminate future environmental contamination for each of the years in the three-year period ended December 31, 2003 were not significant to the consolidated financial statements. Costs of environmental compliance and monitoring aggregated $1.6 million, $1.7 million and $1.3 million for the years ended December 31, 2003, 2002 and 2001, respectively. Our estimated liability for environmental remediation is not discounted.

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. We have excess cost associated with our equity investments in Promix, Dixie, Neptune, La Porte, Nemo and GulfTerra GP. 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 movements of NGL and petrochemical products and natural gas between parties to satisfy timing and logistical needs of the parties. Volumes borrowed from us under such agreements are included in accounts receivable, and volumes loaned to us under such agreements are 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.

On January 1, 2001, we adopted SFAS No. 133 which required us to recognize the fair value of our commodity financial instrument portfolio on the balance sheet based upon then current market conditions. The fair market value of the then outstanding commodity financial instruments portfolio was a net payable of $42.2 million (the cumulative transition adjustment) with an offsetting equal amount recorded in Other Comprehensive Income (OCI). The amount in OCI was fully reclassified to earnings during 2001. See Note 18 for a further discussion of our financial instruments.

GOODWILL consists of 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 will be assessed annually for recoverability. In addition, we will 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.

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.

INTANGIBLE ASSETS consist primarily of the estimated value of contract rights we own arising from agreements with customers (see Note 8). 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 the entity. It is based on an analysis of all pertinent factors including (a) the expected use of the asset by the entity, (b) the expected useful life of related assets (i.e., fractionation facility, storage well, etc.), (c) any legal, regulatory or contractual provisions, including renewal or extension periods that would not cause substantial costs or modifications to existing agreements, (d) the effects of obsolescence, demand, competition, and other economic factors and (e) the level of maintenance required to obtain the expected future cash flows.

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.

We did not recognize any such impairment losses during 2002 or 2001; however, we did record a $1.2 million asset impairment charge related to our Petal NGL fractionator during 2003. 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.

PROPERTY, PLANT AND EQUIPMENT is recorded at cost and is 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 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 except for BEF, which became a majority-owned consolidated subsidiary on September 30, 2003. Prior to January 1, 2004, BEF 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 the first quarter of 2004 will 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, 2003 and 2002, cash and cash equivalents includes $13.9 million and $8.8 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 $20.4 million and $21.2 million at December 31, 2003 and 2002, respectively.

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,		
	2003	**2002**	**2001**
Net income:			
As reported	$ 104,546	$ 95,500	$ 242,178
Additional unit option-based compensation expense estimated using fair-value based method	(1,107)	(2,077)	(1,684)
Pro forma	$ 103,439	$ 93,423	$ 240,494
Basic earnings per unit:			
As reported	$ 0.42	$ 0.55	$ 1.70
Pro forma	0.41	0.53	1.68
Diluted earnings per unit:			
As reported	$ 0.41	$ 0.48	$ 1.39
Pro forma	0.40	0.47	1.38

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the assumptions shown in the following table.

	2003	**2002**	**2001**
Expected life of options	7 years	7 years	7 years
Risk-free interest rate	3.79%	3.10%	3.83%
Expected dividend yield	9.12%	5.65%	5.30%
Expected Unit price volatility	29%	25%	20%

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. OTHER RECENTLY ISSUED ACCOUNTING STANDARDS AND GUIDANCE

Other than those discussed in our general accounting policies (see Note 1), we adopted the following accounting guidance during 2003:

SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and *Technical Corrections*. We adopted provisions of this standard as of January 1, 2003. This statement revised accounting guidance related to the extinguishment of debt and accounting for certain lease transactions. It also amended other accounting literature to clarify its meaning, applicability and to make

various technical corrections. Our adoption of this standard has had no material impact on our financial statements.

SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. This statement amends and clarifies accounting guidance for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. This statement is effective for contracts entered into or modified after June 30, 2003, for hedging relationships designated after June 30, 2003, and to certain preexisting contracts. We adopted SFAS No. 149 on a prospective basis as of July 1, 2003. Our adoption of this standard has had no material impact on our financial statements.

SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and *Equity*. This standard establishes classification and measurement standards for financial instruments with characteristics of both liabilities and equity. It requires an issuer of such financial instruments to reclassify the instrument from equity to a liability or an asset. The effective date of this standard for us was July 1, 2003. Our adoption of this standard has had no material impact on our financial statements.

FIN 45, Guarantor s Accounting and Disclosure Requirement from Guarantees, Including Indirect *Guarantees of Indebtedness of Others*. We implemented this FASB interpretation as of December 31, 2002. This interpretation of SFAS No. 5, 57 and 107, and rescission of FASB Interpretation No. 34 elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. We have provided the information required by this interpretation under Note 9.

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.

3. REVENUE RECOGNITION

The following summarizes our consolidated revenue recognition policies by business activity:

Pipeline, storage and import/export businesses. We enter into pipeline, storage and product handling contracts. Under our NGL, petrochemical and certain natural gas pipeline throughput contracts, revenue is recognized when volumes have been physically delivered for the customer through the pipeline. Revenue from this type of throughput contract is typically based upon a fixed fee per gallon of liquids or MMBtus of natural gas transported, whichever the case may be, multiplied by the volume delivered. The throughput fee is generally contractual or as regulated by various governmental agencies, including the FERC. Additionally, we have product sales contracts associated with our natural gas pipeline business whereby revenue is recognized when we sell and deliver a volume of natural gas to a customer. These natural gas sales contracts are based upon market-related prices as determined by the individual agreements.

In our 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 contract based on the storage rates specified in each contract. Revenues from product handling contracts (applicable to our import and export operations) are recorded once the services have been performed with the applicable fees stated in the individual contracts. In our export operations and certain of our pipelines, we record revenues related to demand fees collected from exporters and shippers when 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 during the slated timeframe.

NGL fractionation, isomerization and propylene fractionation businesses. We enter into NGL fractionation, isomerization and propylene fractionation fee-based (or tolling) arrangements, NGL fractionation percent-of-liquids contracts and propylene fractionation sales contracts. Under our tolling arrangements, we recognize revenue upon completion of all contract services and obligations. These tolling 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 principal variable costs of fractionation and isomerization operations.

At certain of our NGL fractionation facilities, a percent-of-liquids arrangement is utilized. 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. Under a percent-of-liquids arrangement, fractionation revenue is recognized and recorded on a monthly basis for transfers of retained NGL products to the NGL working inventory maintained within our NGL Pipelines & Services segment where it is then held for sale. Transfer pricing for these retained NGLs is based upon monthly market posted prices for such products. This intersegment revenue and offsetting cost to the NGL Pipelines & Services segment is eliminated in our reporting of consolidated revenues and expenses.

In our propylene fractionation product sales contracts, we recognize revenue once the products have been delivered to the customer. Pricing for sales contracts is based upon market-related prices as determined by the individual agreements.

Natural gas processing and related NGL marketing business. In our natural gas processing activities, we enter into margin-band/keepwhole contracts, percent-of-liquids contracts and fee-based contracts. The most significant contract affecting our natural gas processing activities is the 20-year Shell agreement, which is a margin-band, or a modified keepwhole arrangement which grants us the right to process Shell s current and future production with the state and federal waters of the Gulf of Mexico off Texas, Louisiana, Mississippi, Alabama and Florida. Under margin-band/keepwhole arrangements, we retain all of the mixed NGLs extracted from the producer s natural gas stream and recognize revenue when the extracted NGLs are delivered out of our inventory and sold to customers on sales contracts within our NGL marketing activities. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract, inventory, sell and deliver is less than the total amount of NGLs extracted. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract. If a cash fee for services is stipulated by the contract, we record revenue once the natural gas has been processed and sent back to the producer (i.e., delivery has taken place).

Our NGL marketing activities within this segment use product sales contracts to sell and deliver out of inventory the NGLs transferred to it as a result of our keepwhole and percent-of-liquids arrangements and those it purchases for cash 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 specified in each individual contract. Pricing terms in these sales contracts are based upon market-related prices for such products and can include pricing differentials due to factors such as differing delivery locations.

Octane enhancement business. Our octane enhancement business consists of our interest in Belvieu Environmental Fuels (BEF), which owns and operates a facility that produces motor gasoline additives to enhance octane. This facility currently produces MTBE. BEF s operations primarily occur as a result of a contract with Sunoco, Inc. (Sun) whereby Sun is obligated to purchase all of the facility s MTBE output at market-related prices through September 2004. BEF recognizes its revenue once the product has been delivered to Sun.

In September 2003, we acquired an additional 33.3% interest in BEF. As a result, BEF became a majority-owned consolidated subsidiary of ours on September 30, 2003. Previously, BEF was accounted for as an equity-method unconsolidated affiliate. For the periods prior to our consolidation of BEF, gross operating margin for this segment consisted of our equity earnings from BEF, which in turn were dependent upon BEF s general revenue recognition policy. There has been no change in BEF s revenue recognition policies since we began consolidating its financial results with those of our own.

Other businesses. As part of our NGL Pipelines & Services segment activities, we perform NGL marketing services for a small number of customers for which we charge a commission. Commissions are based on either a percentage of the final sales price negotiated on behalf of the client or a fixed-fee per gallon based on the volume sold for the client. Revenues are recorded at the time the services are complete.

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 20 for additional information regarding intersegment and intrasegment revenues and a reconciliation of total segment revenues to total consolidated revenues.

4. BUSINESS COMBINATIONS

During 2003, we acquired EPIK s remaining 50% ownership interest, the Port Neches Pipeline, an additional 33.33% interest in BEF, an additional 37.4% interest in Wilprise and the remaining capital stock of OTC. We also made minor adjustments to the allocation of the purchase price we paid to acquire indirect interests in Mid-America and Seminole pipelines. Due to the immaterial nature of each transaction or event, individually and in the aggregate, our discussion of each of these transactions is limited to the following:

Acquisition of remaining 50% interest in EPIK. In March 2003, we purchased the remaining 50% ownership interests in EPIK. EPIK owns an NGL export terminal located in southeast Texas on the Houston Ship Channel. As a result of this acquisition, EPIK became a consolidated wholly owned subsidiary of ours (previously, it had been an equity-method unconsolidated affiliate).

Acquisition of Port Neches Pipeline. In March 2003, we acquired entities owning the Port Neches Pipeline (formerly known as the Quest Pipeline). The 70-mile Port Neches Pipeline transports high-purity grade isobutane produced at our facilities in Mont Belvieu to customers in Port Neches, Texas.

Acquisition of 33.3% interest in BEF. At the end of September 2003, we acquired an additional 33.3% ownership interest in BEF, which owns a facility that currently produces MTBE (a motor gasoline additive that enhances octane and is used in reformulated gasoline). Due to 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.

Acquisition of 37.4% interest in Wilprise. In October 2003, we acquired an additional 37.4% in Wilprise, which is a 30-mile NGL pipeline that extends from the interconnect with the Tri-States pipeline near Kenner, Louisiana to Sorrento, Louisiana. Due to this acquisition, Wilprise became a majority-owned consolidated subsidiary of ours on October 1, 2003. Previously, Wilprise was accounted for as an equity-method unconsolidated affiliate.

Acquisition of remaining capital stock of OTC. In November 2003, we purchased the remaining 50% of OTC s outstanding capital stock. OTC owns an above ground polymer grade propylene storage and export facility located in Seabrook, Texas that is affiliated with our Mont Belvieu propylene fractionation operation. Due to this acquisition, OTC became a wholly owned consolidated subsidiary of ours. In August 2003, we became operator of the export facility. As a result of obtaining significant control over OTC through our role as operator and having an existing owner and customer relationship with the facility, we began consolidating OTC s financial statements with ours beginning August 1, 2003. Previously, OTC was accounted for as an equity-method unconsolidated affiliate.

Other purchase price adjustments. We made purchase price adjustments relating to our $1.2 billion acquisition of indirect interests in the Mid-America and Seminole pipelines. These adjustments total a net $4.9 million and primarily relate to liabilities existing at July 31, 2002, which was the closing date of the acquisitions.

The following table shows our allocation of the purchase price for 2003 acquisitions, effects of consolidating entities that were formerly accounted for under the equity-method, and adjustments to purchase price allocations from prior periods. The fair value estimates for the EPIK, Port Neches, BEF, Wilprise and OTC transactions were developed using recognized business valuation techniques.

	2003 Business Acquisitions	Purchase Price Adjustments	Total
Cash and cash equivalents	$ 19,800		$ 19,800
Accounts receivable	8,906	$ (172)	8,734
Inventories	10,727		10,727
Prepaid and other current assets	7,024	(1,525)	5,499
Property, plant and equipment, net	110,522	20,930	131,452
Investments in and advances to unconsolidated affiliates	(57,172)		(57,172)
Intangible assets	4,057		4,057
Goodwill	880		880
Other assets	3,332	(124)	3,208
Accounts payable	(5,094)		(5,094)
Accrued gas payables	(5,370)		(5,370)
Accrued expenses	(3,725)	(1,887)	(5,612)
Other current liabilities	(4,615)	(11,449)	(16,064)
Other liabilities	(5,001)	(1,062)	(6,063)
Minority interest	(32,002)	168	(31,834)
Total net assets recorded	$ 52,269	$ 4,879	$ 57,148
Investee cash balances recorded upon consolidation	(19,800)		(19,800)
Business combinations, net of cash received	$ 32,469	$ 4,879	$ 37,348

Proposed Merger with GulfTerra

On December 15, 2003, we and certain of our affiliates, El Paso, and GulfTerra and certain of its affiliates entered into a series of agreements under which one of our wholly-owned subsidiaries and GulfTerra would merge, with GulfTerra surviving the merger and becoming a wholly-owned subsidiary of ours. Formed in 1993, GulfTerra is a publicly traded limited partnership (NYSE symbol, GTM) that manages a portfolio of interests and assets relating to the midstream energy sector. El Paso is the ultimate parent of GulfTerra s general partner and owns a 31.8% limited partner interest in GulfTerra. In general, GulfTerra s business lines include:

Ownership or interests in over 15,700 miles of natural gas pipeline systems. These pipeline systems include gathering systems onshore in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas and offshore in drilling and development regions in the Gulf of Mexico. GulfTerra also owns interests in five natural gas processing and treating plants located in New Mexico, Texas and Colorado;

Ownership in over 1,000 miles of intrastate NGL gathering and transportation pipelines and four NGL fractionation plants located in Texas. GulfTerra also owns interests in three offshore oil pipeline systems, which extend over 340 miles, owns a 3.3 MMBbl propane storage and leaching business located in Mississippi and owns or leases NGL storage facilities in Louisiana and Texas with aggregate capacity of approximately 21.3 MMBbls;

Ownership in two salt dome natural gas storage facilities located in Mississippi that have a combined current working capacity of 13.5 Bcf. In addition, GulfTerra has the exclusive right to use a natural gas storage facility located in Wharton, Texas under an operating lease that expires in January 2008. This facility has a working gas capacity of 6.4 Bcf;

Interests in six multi-purpose offshore hub platforms in the Gulf of Mexico that were specifically designed to be used as deepwater hubs and production handling and pipeline maintenance facilities; and

Interests in four oil and natural gas producing properties located in waters offshore Louisiana. Production is gathered, transported, and processed through GulfTerra s pipeline systems and platform facilities, and sold to various third parties and El Paso.

GulfTerra is one of the largest natural gas gatherers, based on miles of pipeline, in the prolific natural gas supply regions offshore in the Gulf of Mexico and onshore in Texas and in the San Juan Basin, which covers a significant portion of the four contiguous corners of Arizona, Colorado, New Mexico and Utah.

The proposed merger is a three-step process outlined as follows:

Step One. On December 15, 2003, we purchased a 50% membership interest in GulfTerra s general partner (GulfTerra Energy Company, L.L.C. or GulfTerra GP) for $425 million. This investment is accounted for using the equity method. This transaction is referred to as Step One of the proposed merger and will remain in effect even if the remainder of the proposed merger and post-merger transactions, which we refer to as Step Two and Three, do not occur.

Step Two. If all necessary regulatory and unitholder approvals are received and the other merger agreement conditions are either fulfilled or waived and the following steps are consummated, we will own 100% of the limited and general partner interests in GulfTerra. At that time, the proposed merger will be accounted for using the purchase method and GulfTerra will be a consolidated subsidiary of our company. Step Two of the proposed merger includes the following transactions:

El Paso s contribution to our General Partner of El Paso s remaining 50% interest in GulfTerra GP for a 50% interest in our General Partner, and the subsequent capital contribution by our General Partner of such 50% interest in GulfTerra GP to us (without increasing our General Partner s interest in our earnings or cash distributions).

Our purchase of 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units owned by El Paso for $500 million; and

The exchange of each remaining GulfTerra common unit for 1.81 Enterprise common units, resulting in the issuance of approximately 103 million Enterprise common units to GulfTerra unitholders.

Step Three. Immediately after Step Two is completed, we expect to acquire nine cryogenic natural gas processing plants, one natural gas gathering system, one natural gas treating plant, and a small natural gas liquids connecting pipeline from El Paso for $150 million. We refer to the assets that we will acquire from El Paso as the South Texas midstream assets.

Our preliminary estimate of the total consideration for Steps One, Two and Three we would pay or grant is approximately $3.9 billion. For a period of three years following the closing of the proposed merger, El Paso will provide support services to GulfTerra similar to those provided by El Paso prior to the closing of the merger. GulfTerra will reimburse El Paso for 110% of its direct costs of such services (excluding any overhead costs). El Paso will make transition support payments to us in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in 12 equal monthly installments for each such year. These transition support payments are included in our preliminary estimate of total consideration.

We are working to complete the merger as soon as possible. A number of conditions must be satisfied before we can complete the merger, including approval by the unitholders of both the Company and GulfTerra and the expiration or termination of applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1974. While we cannot predict if and when all of the conditions to the merger will be satisfied, we expect to complete the merger in the second half of 2004.

To review a copy of the merger agreement and related transaction documents, please read our Current Report on Form 8-K filed with the Securities and Exchange Commission on December 15, 2003.

5. INVENTORIES

Our inventories were as follows at the dates indicated:

	December 31,	
	2003	2002
Working inventory	$ 135,451	$ 131,769
Forward-sales inventory	14,710	35,600
Inventory	$ 150,161	$ 167,369

A description of each inventory 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 in-kind 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 our NGL Pipelines & Services segment's NGL marketing activities;
Natural gas inventory write downs are recorded as a cost of our Onshore Natural Gas Pipelines & Services Acadian Gas operations; and
Petrochemical inventory write downs are recorded as a cost of our Petrochemical Services marketing activities or as a cost of its octane additive business.

For the years ended December 31, 2003, 2002 and 2001, we recognized LCM adjustments of approximately $16.9 million, $6.3 million and $40.7 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.

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	December 31, 2003	December 31, 2002
Plants and pipelines[1]	5-35[4]	$3,214,463	$2,860,180
Underground and other storage facilities[2]	5-35[5]	288,199	283,114
Transportation equipment[3]	3-10	5,676	5,118
Land		23,447	23,817
Construction in progress		74,431	49,586
Total		3,606,216	3,221,815
Less accumulated depreciation		642,711	410,976
Property, plant and equipment, net		$2,963,505	$2,810,839

(1) Plants and pipelines includes processing plants; NGL, petrochemical 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) Transportation equipment includes vehicles and similar assets used in our operations.
(4) In general, the estimated useful lives of major components of this category are: processing plants, 20-35 years, pipelines, 30-35 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.
(5) In general, the estimated useful lives of major components of this category are: underground storage wells, 30-35 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, 2003, 2002 and 2001 was $101.0 million, $72.5 million and $43.4 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. Under the implementation guidelines of SFAS No. 143, we reviewed our long-lived assets for ARO liabilities and identified such liabilities in several 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 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 Gulf of Mexico natural gas pipelines owned by our equity method investees, Starfish, Neptune and Nemo, have identified ARO s relating to regulatory requirements. At present, these entities have no plans to abandon or retire their major transmission pipelines; however, there are plans to retire certain minor gas gathering lines periodically through 2013. Should the management of these companies decide to abandon or retire their major transmission pipelines, an ARO liability would be recorded at that time. With regard to the minor gas gathering pipelines scheduled for retirement, Starfish and Neptune collectively recorded ARO liabilities during 2003 totaling $2.8 million (on a gross basis).

7. INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES

We own interests in a number of related businesses that are accounted for under the equity or cost methods. The investments in and advances to these unconsolidated affiliates are grouped according to the business segment to which they relate. For a general discussion of our business segments, see Note 20.

The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated:

	Ownership Percentage	December 31, 2003	December 31, 2002
Accounted for on equity basis:			
Offshore Pipelines & Services:			
Starfish	50.0%	$ 40,664	$ 28,512
Neptune	25.7%	74,647	77,365
Nemo	33.9%	12,294	12,423
Onshore Natural Gas Pipelines & Services:			
Evangeline	49.5%	2,519	2,383
NGL Pipelines & Services:			
BRF	32.3%	27,892	28,293
Promix	33.3%	38,903	41,643
Wilprise (1)	37.4%		8,566
Tri-States (2)	50.0%	44,119	25,552
Belle Rose	41.7%	10,780	11,057
Dixie	19.9%	35,988	36,660
EPIK (1)	50.0%		11,114
VESCO	13.1%	33,000	33,000
Petrochemical Services:			
BRPC	30.0%	16,584	17,616
La Porte	50.0%	5,422	5,737
OTC (1)	50.0%		2,178
BEF (1)	33.3%		54,894
Other, non-segment:			
GulfTerra GP (3)	50.0%	424,947	
Total		$ 767,759	$ 396,993

(1) We acquired additional ownership interests in these entities during 2003 resulting in our consolidation of each company s post-acquisition financial results with those of our own. See Note 4 for information regarding these acquisitions.
(2) In October 2003, we acquired an additional 16.7% ownership interest in Tri-States from Williams.
(3) In December 2003, we acquired a 50% interest in the general partner of GulfTerra Energy Partners, L.P. from El Paso.

At December 31, 2003, our share of accumulated earnings of equity method unconsolidated affiliates that had not been remitted to us was approximately $38.6 million.

Our initial investment in Promix, La Porte, Dixie, Neptune, Nemo and GulfTerra GP exceeded our share of the historical cost of the underlying net assets of such entities (excess cost). The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. The excess cost amounts related to Promix, Neptune, La Porte and Nemo are attributable to the tangible plant and pipeline assets of each entity, and are amortized against equity earnings from these entities in a manner similar to depreciation. The excess cost of Dixie includes amounts attributable to both goodwill and tangible pipeline assets, with the portion assigned to the pipeline assets being amortized in a manner similar to depreciation. The excess cost of GulfTerra GP has been attributed to goodwill and represents our preliminary allocation of the purchase price of this interest pending completion of a fair value analysis which is expected to be completed during the last half of 2004. The goodwill inherent in Dixie s and GulfTerra GP s excess cost is not amortized but is subject to evaluation for impairment as described in Note 1 under Excess Cost over Underlying Equity in Net Assets. To the extent that our preliminary allocation of the excess cost of GulfTerra GP is ultimately attributed to depreciable or amortizable assets, our equity earnings from GulfTerra GP will be reduced. The following table summarizes our excess cost information at the dates and for the periods indicated:

		Initial Excess Cost attributable to		Unamortized balance at December 31,		Amortization charged against equity earnings during 2003
	Amort. Periods	Tangible assets	Goodwill	2003	2002	
Promix	20 years	$ 7,955		$ 6,256	$ 6,596	$ 340
La Porte	35 years	873		789	833	44
Dixie	35 years(1)	28,448	$ 9,246	34,084	34,901	817
Neptune	35 years	12,768		11,674	12,039	365
Nemo	35 years	727		676	697	21
GulfTerra GP	n/a (1)		328,214	328,214		

(1) Excess cost attributable to goodwill is not amortized; however, our investments in unconsolidated affiliates (which include excess cost amounts) are tested for impairment whenever events or circumstances indicate that there is a loss in value of the investment which is an other than temporary decline.

The table below shows the potential decrease in equity earnings from GulfTerra GP if certain amounts of the $328.2 million of excess cost preliminarily attributable to goodwill were ultimately assigned to fixed or intangible assets. For purposes of calculating this sensitivity, we have applied the straight-line method of cost allocation (i.e. depreciation or amortization) over an estimated useful life of 20-years to various fair values.

	Excess Cost attributed to tangible or intangible assets	Estimated Annual Reduction in Equity Earnings
20% of excess cost	$ 65,643	$ 3,282
40% of excess cost	131,286	6,564
60% of excess cost	196,928	9,846
80% of excess cost	262,571	13,129
100% of excess cost	328,214	16,411

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

	Ownership Percentage	For Year Ended December 31, 2003	2002	2001
Offshore Pipelines & Services:				
Starfish	50.0%	$ 3,279	$ 7,346	$ 4,122
Ocean Breeze [3]	25.7%			32
Neptune	25.7%	1,014	2,111	4,081
Nemo	33.9%	1,268	1,077	75
Onshore Natural Gas Pipelines & Services:				
Evangeline	49.5%	131	(58)	(145)
NGL Pipelines & Services:				
BRF	32.3%	832	2,427	1,583
Promix	33.3%	2,106	3,936	4,201
EPIK [1]	50.0%	1,818	4,688	345
Dixie	19.9%	1,323	1,231	2,092
Wilprise [1]	37.4%	276	948	472
Tri-States [2]	33.3%	1,542	1,959	1,565
Belle Rose	41.7%	(55)	203	103
Petrochemical Services:				
BRPC	30.0%	1,198	997	1,161
La Porte	50.0%	(698)	(559)	
OTC [1]	50.0%	(77)	378	
BEF [1,5]	33.3%	(27,864)	8,569	5,671
Other, non-segment:				
Gulf Terra [4]	50.0%	(53)		
Total		$ (13,960)	$ 35,253	$ 25,358

(1) We acquired additional ownership interests in these entities during 2003 resulting in our consolidation of each company s post-acquisition financial results with those of our own. Equity earnings presented for 2003 for each company are for the period January 1, 2003 through acquisition date. See Note 4 for information regarding these acquisitions.
(2) In October 2003, we acquired an additional 16.7% ownership interest in Tri-States from Williams.
(3) Ocean Breeze was merged into Neptune in November 2001.
(4) On December 15, 2003, we acquired a 50% interest in the general partner of GulfTerra Energy Partners, L.P. from El Paso. Equity earnings presented for GulfTerra GP are for the period December 15, 2003 through December 31, 2003.
(5) Equity earnings from BEF for 2003 include a $22.5 million charge related to an asset impairment.

As used in the following condensed financial data, operating income represents earnings before non-operating income and expense items such as interest income and interest expense. The equity earnings we record from these investments represent our share of the net income of each.

Offshore Pipelines & Services segment

At December 31, 2003, our Offshore Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Starfish Pipeline Company, LLC (Starfish) a 50% interest in the Stingray natural gas pipeline and related dehydration and other facilities located in south Louisiana and the Gulf of Mexico offshore Louisiana. We do not exercise management control over Starfish and are precluded from consolidating its financial statements with our financial statements.
Neptune Pipeline Company, L.L.C. (Neptune) a 25.7% interest in the Manta Ray and Nautilus natural gas pipeline systems owned by Manta Ray Offshore Gathering Company, LLC and Nautilus Pipeline Company LLC located in the Gulf of Mexico offshore Louisiana.
Nemo Gathering Company, LLC (Nemo) a 33.9% interest in the Nemo natural gas pipeline located in the Gulf of Mexico offshore Louisiana.

Onshore Natural Gas Pipelines & Services segment

At December 31, 2003, our Onshore Natural Gas Pipelines & Services segment included *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. We account for our investment in Evangeline using the equity method.

NGL Pipelines & Services segment

At December 31, 2003, our NGL Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Baton Rouge Fractionators LLC (BRF) an approximate 32.3% interest in an NGL fractionator located in southeastern Louisiana.
K/D/S Promix LLC (Promix) a 33.3% interest in an NGL fractionator and related storage and pipeline assets located in south Louisiana.
Tri-States NGL Pipeline LLC (Tri-States) an aggregate 50% interest in an NGL pipeline system located in Louisiana, Mississippi and Alabama. In October 2003, we purchased an additional 16.7% interest in Tri-States from Williams. We do not exercise management control over Tri-States and are precluded from consolidating its financial statements with our financial statements.
Belle Rose NGL Pipeline LLC (Belle Rose) a 41.7% interest in an NGL pipeline system located in south Louisiana.
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.

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. See Note 4 for additional information regarding our business combinations.

At December 31, 2003, our investments in and advances to unconsolidated affiliates also includes *Venice Energy Services Company, LLC* (VESCO). The VESCO investment consists of a 13.1% interest in a company owning a natural gas processing plant, fractionation facilities, storage, and gas gathering pipelines in the Gulf of Mexico. We account for this investment using the cost method. As part of Other Income and Expense as shown in our Statements of Consolidated Operations and Comprehensive Income, we record dividend income from our investment in VESCO.

Petrochemical Services segment

At December 31, 2003, our Petrochemical Services segment included the following unconsolidated affiliates accounted for using the equity method:

La Porte Pipeline Company, L.P. and *La Porte Pipeline GP, LLC* (collectively La Porte) an aggregate 50% interest in a private polymer grade propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas. We do not exercise management control over La Porte and, therefore, are precluded from consolidating its financial statements with our financial statements.
Baton Rouge Propylene Concentrator, LLC (BRPC) a 30.0% interest in a propylene fractionator located in southeastern Louisiana.

In November 2003, we purchased the remaining 50% of outstanding common stock of Olefins Terminal Corporation (OTC) from Valero. 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 currently produces MTBE, a motor gasoline additive that enhances octane and is used in reformulated motor gasoline. Due to 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.

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.

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 19 for additional information regarding risks associated with our investment in BEF.

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 purchased this interest from El Paso on December 15, 2003 for $425 million. Our purchase of this interest was Step One of our merger with GulfTerra. See Note 4 for additional information regarding this business combination. We do not exercise management control over GulfTerra GP and are precluded from consolidating its financial statements with our financial statements.

Condensed Financial Information of our Equity-Method Unconsolidated Affiliates

The aggregate combined balance sheet information for the last two years and results of operations data for the last three years of our equity method investments are summarized in the following table.

	At December 31, 2003	At December 31, 2002
BALANCE SHEET DATA:		
Current assets	$ 69,340	$ 137,663
Property, plant and equipment, net	724,129	889,598
Other assets	234,953	56,551
Total assets	$ 1,028,422	$ 1,083,812
Current liabilities	$ 57,693	$ 88,500
Other liabilities	55,619	67,047
Combined equity	915,110	928,265
Total liabilities and combined equity	$ 1,028,422	$ 1,083,812

	For Year Ended December 31, 2003	2002	2001
INCOME STATEMENT DATA:			
Revenues	$ 559,943	$ 611,275	$ 595,618
Non-cash impairment charge	(67,482)		
Operating income	19,659	114,780	92,839
Net income	4,080	105,842	80,767

8. INTANGIBLE ASSETS AND GOODWILL

Intangible assets

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

		At December 31, 2003		At December 31, 2002	
	Gross Value	**Accum. Amort.**	**Carrying Value**	**Accum. Amort.**	**Carrying Value**
Shell natural gas processing agreement	$206,216	$(34,063)	$172,153	$(23,015)	$183,201
Storage II contracts	8,127	(464)	7,663	(232)	7,895
Splitter III contracts	53,000	(2,902)	50,098	(1,388)	51,612
Toca-Western natural gas processing contracts	11,187	(885)	10,302	(326)	10,861
Toca-Western NGL fractionation contracts	20,042	(1,587)	18,455	(585)	19,457
Venice contracts (1)	6,635	(136)	6,499		4,635
Port Neches pipeline contracts (2)	2,400	(310)	2,090		
BEF UOP License Fee (3)	1,657	(24)	1,633		
Total	$309,264	$(40,371)	$268,893	$(25,546)	$277,661

(1) Amortization commenced when contracted volumes began to be processed during 2003.
(2) Acquired as a result of our purchase of the Port Neches pipeline in March 2003 (see Note 4).
(3) This intangible asset relates to the operations BEF, which we began consolidating on September 30, 2003 as a result of purchasing an additional 33.3% interest (see Note 4).

At December 31, 2003, our intangible assets consisted of:

The Shell natural gas processing agreement that we acquired as part of the TNGL acquisition in August 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.
Certain storage and propylene fractionation contracts we acquired in connection with the Diamond-Koch acquisitions in January and February 2002. 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.
Certain natural gas processing and NGL fractionation contracts we acquired in connection with the Toca-Western acquisition in June 2002. 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.
Certain NGL-related contracts related to our ability to take delivery of purity NGL products and mixed NGLs from VESCO at a lower cost than otherwise would have been incurred. The value of these contracts are being amortized on a straight-line basis over the terms of each contract, which approximate 14 years.
Certain product handling and transportation contracts related to our Port Neches pipeline, the values of which are being amortized on a straight-line basis over the terms of the contracts.
Certain license fees related to the octane enhancement business of BEF, the operations of which we began consolidating on September 30, 2003 (See Note 4). These fees are being amortized over the expected 20-year remaining useful life of the operations to which they relate.

The following table shows amortization expense associated with our intangible assets for the periods indicated:

	For Year Ended December 31,		
	2003	2002	2001
Shell natural gas processing agreement	$ 11,048	$ 11,054	$ 7,260
Mont Belvieu Storage II contracts	232	232	
Mont Belvieu Splitter III contracts	1,514	1,388	
Toca-Western natural gas processing contracts	559	326	
Toca-Western NGL fractionation contracts	1,002	585	
Venice contracts	136		
Port Neches pipeline contracts	310		
BEF UOP license fee (1)	24		
MBA acquisition goodwill (2)			449
Total	$ 14,825	$ 13,585	$ 7,709

(1) Amortization is for the three-month period that BEF was a consolidated subsidiary of ours.

(2) MBA acquisition goodwill was reclassified from Intangible Assets to Goodwill on January 1, 2002 per the transition provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*. In accordance with this accounting standard, we discontinued the amortization of goodwill on January 1, 2002.

For 2004, amortization expense attributable to these intangible assets is currently estimated at $15.3 million. Based on information currently available, we expect that amortization expense relating to existing intangible assets will also approximate $15.3 million for each of the years 2005 through 2008.

Goodwill

Our goodwill is attributable to the excess of the purchase price of an acquired entity over the net amounts assigned to identifiable assets acquired (including identifiable intangible assets) and liabilities assumed. Goodwill is not amortized; however, it is subject to periodic impairment testing. The following table summarizes our goodwill amounts at the dates indicated:

		At December 31,	
	Segment affiliation	2003	2002
Splitter III acquisition (1)	Petrochemical Services	$ 73,690	$ 73,690
MBA acquisition (2)	NGL Pipelines & Services	7,857	7,857
Wilprise acquisition (3)	NGL Pipelines & Services	880	
		$ 82,427	$ 81,547

(1) Amount recorded in connection with our acquisition of propylene fractionation assets from Diamond-Koch in February 2002.

(2) Amount recorded in connection with our acquisition of an additional interest in Mont Belvieu Associates in July 2001, which in turn owned an interest in our Mont Belvieu NGL fractionation facility.

(3) Amount recorded in connection with our acquisition of an additional 37.4% interest in Wilprise in October 2003.

Since our adoption of SFAS No. 142 on January 1, 2002, our goodwill amounts are no longer amortized but are assessed annually for recoverability. Prior to our adoption of this standard, the only goodwill amortization we recorded was that associated with the MBA acquisition in July 1999. Due to the immaterial nature of such amortization expense ($0.4 million in 2001), the pro forma effect of not amortizing this goodwill in 2001 would have had a negligible effect on our net income and basic and diluted earnings per unit.

9. DEBT OBLIGATIONS

Our debt consisted of the following at the dates indicated:

	December 31, 2003	December 31, 2002
Borrowings under:		
364-Day Term Loan, variable rate, repaid during 2003 [(1)]		$ 1,022,000
Interim Term Loan, variable rate, due the earlier of September 2004 or the date that our proposed merger with GulfTerra is completed (see Note 4)	$ 225,000	
364-Day Revolving Credit Facility, variable rate, due October 2004, $230 million borrowing capacity	70,000	99,000
Multi-Year Revolving Credit Facility, variable rate, due November 2005, $270 million borrowing capacity [(2)]	115,000	225,000
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	350,000
Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 2005 [(3)]	30,000	45,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
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	
Senior Notes D, 6.875% fixed rate, due March 2033	500,000	
Total principal amount	2,144,000	2,245,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,531	1,774
Less unamortized discounts on Senior Notes A, B and D	(5,983)	(311)
Subtotal long-term debt	2,139,548	2,246,463
Less current maturities of debt [(4)]	(240,000)	(15,000)
Long-term debt [(4)]	$ 1,899,548	$ 2,231,463
Standby letters of credit outstanding, $75 million of credit capacity available under our Multi-Year Revolving Credit Facility [(2)]	$ 1,300	$ 2,400

(1) We used a combination of proceeds from the issuance of Senior Notes C and D and the January 2003 common unit offering to fully repay this facility in February 2003.
(2) This facility has $270 million of total borrowing capacity, which is reduced by the amount of standby letters of credit outstanding.
(3) As to the assets of our subsidiary, Seminole Pipeline Company, our $2.1 billion in senior indebtedness at December 31, 2003 is structurally subordinated and ranks junior in right of payment to the $30 million of indebtedness of Seminole Pipeline Company.
(4) 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, 2003 reflect the classification of such debt obligations at March 1, 2004. With respect to our 364-Day Revolving Credit Facility, borrowings under this facility are not included in current maturities because we have the option and ability to convert any revolving credit balance outstanding at maturity to a one-year term loan (due October 2005) in accordance with the terms of the agreement.

See Note 16 for our scheduled future maturities of long-term debt at December 31, 2003.

Parent-subsidiary guarantor relationships

We act as guarantor of all of our Operating Partnership s consolidated debt obligations, with the exception of the Seminole Notes. 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 78.4% of its capital stock).

General description of debt

The following is a summary of the significant aspects of our debt obligations at December 31, 2003.

Interim Term Loan. In December 2003, our Operating Partnership entered into a $225 million acquisition-related term loan to partially finance our $425 million purchase from El Paso of a 50% membership interest in GulfTerra GP (see Note 7). The maturity date of this term loan is the earlier of September 2004 or the date our proposed merger with GulfTerra (see Note 4) is completed. The Operating Partnership s borrowings under this agreement are unsecured general obligations that are non-recourse to our General Partner. We have guaranteed repayment of amounts due under this term loan through an unsecured guarantee.

As defined by the agreement, variable interest rates charged under this facility generally bear interest at either, at our election, (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate. Whichever base rate we select, the rate is increased by an appropriate applicable margin (as defined in the loan agreement). For information regarding variable-interest rates paid under this term loan agreement, please read Information regarding variable-interest rates paid within this Note 9.

This term loan agreement contains various covenants related to our ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires us to satisfy certain financial covenants at the end of each fiscal quarter. If an event of default (as defined in the agreement) occurs, the Operating Partnership is prohibited from making distributions to us, which would impair our ability to make distributions to our partners. As defined in the agreement, we must maintain a specified level of consolidated net worth and certain financial ratios. We were in compliance with these covenants at December 31, 2003.

364-Day Revolving Credit Facility. In October 2003, our Operating Partnership entered into new 364-day revolving credit agreement that contained essentially the same terms as our November 2002 364-Day revolving credit agreement that expired in November 2003. The stand-alone borrowing capacity under the new revolving credit facility is $230 million with the maturity date for any amount outstanding being October 2004. We have the option to convert any revolving credit balance outstanding at maturity to a one-year term loan (due October 2005) in accordance with the terms of the credit agreement. The Operating Partnership s borrowings under this agreement are unsecured general obligations that are non-recourse to our General Partner. We have guaranteed repayment of amounts due under this term loan through an unsecured guarantee.

As defined by the agreement, variable interest rates charged under this facility generally bear interest at either, at our election, (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate. Whichever base rate we select, the rate is increased by an appropriate applicable margin (as defined in the loan agreement). We elect the basis of the interest rate at the time of each borrowing. For information regarding variable-interest rates paid under this revolving credit agreement, please read Information regarding variable-interest rates paid within this Note 9.

This revolving credit agreement contains various covenants similar to those of our Interim Term Loan (please refer to our discussion regarding restrictive covenants of the Interim Term Loan within this *General description of debt* section). We were in compliance with these covenants at December 31, 2003.

Multi-Year Revolving Credit Facility. In November 2002, our Operating Partnership entered into a five-year revolving credit facility that includes a sublimit of $75 million for standby letters of credit. Currently, the stand-alone borrowing capacity under this revolving credit facility is $270 million. The Operating Partnership s borrowings under this agreement are unsecured general obligations that are non-recourse to our General Partner. We have guaranteed repayment of amounts due under this term loan through an unsecured guarantee.

As defined by the agreement, variable interest rates charged under this facility generally bear interest at either, at our election, (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate. We elect the basis of the interest rate at the time of each borrowing. For information regarding variable-interest rates paid under this revolving credit agreement, please read Information regarding variable-interest rates paid within this Note 9.

This revolving credit agreement contains various covenants similar to those of our Interim Term Loan (please refer to our discussion regarding restrictive covenants of the Interim Term Loan within this *General description of debt* section). We were in compliance with these covenants at December 31, 2003.

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 our General Partner. 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, 2003.

In January 2003, we issued $350 million in principal amount of 6.375% fixed-rate senior notes due February 2013 (Senior Notes C), from which we received net proceeds before offering expenses of approximately $347.7 million. These private placement notes were sold at face value with no discount or premium. We used the proceeds from this offering to repay a portion of the indebtedness outstanding under the 364-Day Term Loan that we incurred to finance the Mid-America and Seminole acquisitions. In May 2003, we exchanged 100% of the private placement Senior Notes C for publicly registered Senior Notes C.

In February 2003, we issued $500 million in principal amount of 6.875% fixed-rate senior notes due March 2033 (Senior Notes D), from which we received net proceeds before offering expenses of approximately $489.8 million. These private placement notes were sold at 98.842% of their face amount. We used $421.4 million from this offering to repay the remaining principal balance outstanding under the 364-Day Term Loan. In addition, we applied $60.0 million of the proceeds to reduce the balance outstanding under the 364-Day Revolving Credit Facility. The remaining proceeds were used for working capital purposes. In July 2003, we exchanged 100% of the private placement Senior Notes D for publicly registered Senior Notes D.

Repayment of 364-Day Term Loan

In July 2002, our Operating Partnership entered into the $1.2 billion senior unsecured 364-Day Term Loan to fund the acquisition of interests in the Mid-America and Seminole pipelines. We used $178.5 million of the $182.5 million in proceeds from our October 2002 equity offering to partially repay this loan. We also used $252.8 million of the $258.1 million in proceeds from the January 2003 equity offering (see Note 10), $347.0 million of the $347.7 million in proceeds from our issuance of Senior Notes C and $421.4 million in proceeds from our issuance of Senior Notes D to fully repay the 364-Day Term Loan in February 2003.

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 2003.

	Range of interest rates paid	**Weighted-average interest rate paid**
364-Day Term Loan (1)	2.59% - 2.88%	2.85%
364-Day Revolving Credit Facility	1.79% - 4.75%	2.48%
Multi-Year Revolving Credit Facility	1.64% - 4.25%	1.87%
Interim Term Loan	1.77% - 4.00%	2.16%

(1) This facility was fully repaid in February 2003.

10. CAPITAL STRUCTURE

General

Our common units and Class B special 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 Third Amended and Restated Agreement of Limited Partnership (the Partnership Agreement, together with any amendments thereto). Our outstanding common units are listed on the New York Stock Exchange under the symbol EPD.

In December 2003, we issued Class B special units to an affiliate of EPCO. Class B special units have rights identical to our common units with respect to distributions and other matters. However, the Class B special units do not have voting rights and are 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 has been obtained. The Class B special units are convertible into common units on a one-for-one basis upon the receipt of approval of holders of not less than a majority of our common units (not including for this purpose the Class B special units) present and entitled to vote at a meeting of our common unitholders or by the holders of a majority of our common units (not including for this purpose the Class B special units) pursuant to written consents. We will request that our common unitholders approve the conversion of all of the Class B special units into common units at the special meeting that will be held to approve our merger with GulfTerra.

In December 2003, we restructured our General Partner 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.

In February 2002, our General Partner 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.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that the common units, Class B special units and General Partner will receive. See Note 11 for additional information regarding our distributions to partners.

The Partnership Agreement also contains provisions for the allocation of net earnings and losses to the unitholders and the 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. For financial accounting and tax purposes, the Class A special units (prior to their final conversion to common units in August 2003), were not allocated any portion of net income or loss; however, for tax purposes these units were allocated a certain amount of depreciation. 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 the General Partner. See Note 11 for information regarding incentive cash distributions.

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 the General Partner in its sole discretion with 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 from Common Unit Offerings			
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 (6)	1,577,744	32,696	334	334	33,364
Total 2003	29,506,303	$ 567,945	$ 5,739	$ 5,861	$ 579,545

(1) Prior to the restructuring of our General Partner s ownership interest in December 2003, the General Partner 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 outstanding 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 outstanding 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) We used the net proceeds from this offering to reduce indebtedness outstanding under our revolving credit facilities and for general partnership purposes.
(6) We used the net proceeds from this offering for general partnership purposes.

In January 2003, we filed a $1.5 billion universal registration statement with the SEC covering the issuance of an unallocated amount of partnership equity or public debt obligations (separately or in combination). Our June 2003 equity offering utilized capacity available under this shelf. At December 31, 2003, we had approximately $1.2 billion of unused capacity under this shelf registration statement.

During 2003, we instituted a distribution reinvestment plan (DRP) for our unitholders. The DRP 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. The registration statement we filed with the SEC relating to the DRP allows us to issue up to 5,000,000 common units under this program. As a result of any reinvestment proceeds we receive, our General Partner is required to make cash contributions to us in order to maintain its ownership interest. Initial reinvestments under this program occurred in August 2003.

In December 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO for $100 million in a private transaction. Our General Partner contributed approximately $2 million in connection with this offering in order to maintain its ownership interest. The purchase price for the Class B special units was approximately $22.66 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. 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 (see Note 7) and the remainder for general partnership purposes.

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 the 1999 TNGL acquisition 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 the 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 the General Partner). The 1999 Trust is included in our consolidated financial statements. Beginning in 2000, we and the 1999 Trust were authorized by the General Partner 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.

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.

The 1999 Trust purchased 792,800 common units during 2001 at a cost of $18 million and 100,000 common units during 2002 at a cost of $2.4 million. In 2001, the 1999 Trust sold 1,000,000 common units held in treasury to EPCO for $22.6 million. The sales price of these treasury units exceeded the purchase price of the treasury units by $6.0 million and was credited to partners equity as a general contribution. We purchased 432,000 common units during 2002 at a cost of $10.3 million. In addition, 51,959 treasury units were reissued during 2002 at a weighted-average cost of $1.2 million to fulfill our obligations under EPCO employee unit option agreements. 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 at a cost of $0.6 million during 2003.

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	**Subordinated Units**	**Class A Special Units**	**Class B Special Units**	**Treasury Units**
Balance, January 1, 2001	92,514,630	42,819,740	33,000,000		534,400
Class A special units issued to Shell in connection with contingent unit agreement in August 2001			6,000,000		
Conversion of Class A special units to common units in August 2001	10,000,000		(10,000,000)		
Treasury unit transactions:					
Purchased	(792,800)				792,800
Reissued	1,000,000				(1,000,000)
Balance, December 31, 2001	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)	1,306,059				
Common units issued in November 2003 (1)	1,577,744				
Common units issued in December 2003	20,000				
Class B special units issued in December 2003				4,413,549	
Treasury unit transactions:					
Reissued	30,887				(30,887)
Retired					(30,000)
Balance, December 31, 2003	213,366,760	-	-	4,413,549	798,313

(1) Units issued primarily due to distribution reinvestment plan.

11. DISTRIBUTIONS

We intend, 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, our General Partner s percentage interest in our quarterly cash distributions is increased after certain specified target levels are met. In December 2002, we amended our Partnership Agreement to eliminate the General Partner 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, our General Partner 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 the General Partner to give up this right. As amended, our General Partner s quarterly incentive distribution thresholds are as follows (which include adjustments for the December 2003 restructuring of the General Partner 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 the General Partner of $19.7 million, $9.8 million and $3.2 million during the years ended December 31, 2003, 2002 and 2001, 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
2001			
1st Quarter	$ 0.2750	Apr. 30, 2001	May 10, 2001
2nd Quarter	$ 0.2938	Jul. 31, 2001	Aug. 10, 2001
3rd Quarter	$ 0.3125	Oct. 31, 2001	Nov. 9, 2001
4th Quarter	$ 0.3125	Jan. 31, 2002	Feb. 11, 2002
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

(1) Distributions are paid on common units, subordinated units and Class B special units.

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 pipeline and our Seminole pipeline and federal tax obligations of our Seminole pipeline (both 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 is a summary of the provision for income taxes for the above-mentioned pipeline operations for the periods indicated:

	For Year Ended December 31,	
	2003	2002
Current:		
Federal tax benefit		$ (391)
State tax expense (benefit)	$ 47	(55)
Total current	47	(446)
Deferred:		
Federal	4,556	1,812
State	690	268
Total deferred	5,246	2,080
Provision for income taxes	$ 5,293	$ 1,634

Our net deferred tax assets primarily relate to book versus tax basis differences in property, plant and equipment.

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 common and subordinated units and Class B special units outstanding during a period. 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 common and subordinated units and Class A and Class B special 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).

In a period of net operating losses, the Class A special units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. Treasury units are not considered to be outstanding units; therefore, they are excluded from the computation of both basic and diluted earnings per unit.

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 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 reissued treasury units to satisfy the exercise of a small number of common unit options by employees of EPCO. 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 or loss allocated to limited partner interests is derived by subtracting our General Partner s share of our net income or loss and that attributable to the minority interest from income before minority interest. The following table shows the allocation of net income or loss to our General Partner for the periods indicated:

	For Year Ended December 31,		
	2003	2002	2001
Net income	$ 104,546	$ 95,500	$ 242,178
Less priority earnings allocations to General Partner (1)	(19,699)	(9,806)	(3,218)
Net income available after priority earnings allocation	84,847	85,694	238,960
Multiplied by General Partner ownership interest (2)	1.2%	1.0%	1.0%
Standard earnings allocation to General Partner	$ 1,030	$ 857	$ 2,390
Priority earnings allocation to General Partner	$ 19,699	$ 9,806	$ 3,218
Standard earnings allocation to General Partner	1,030	857	2,390
General Partner interest	$ 20,729	$ 10,663	$ 5,608

(1) See Note 10 for information regarding priority earnings allocations to our General Partner.

(2) The General Partner s ownership interest in us increased from 1% to 2% in December 2003 as a result of restructuring its overall ownership interest in us and our Operating Partnership. The amount shown in the table represents a weighted-average of the General Partner s ownership interest in us during 2003. See Note 10 for information regarding this change in ownership structure.

The following table shows our calculation of net income available to limited partners, basic earnings per unit and diluted earnings per unit for the periods indicated:

	For Year Ended December 31,		
	2003	2002	2001
Income before minority interest	$ 108,405	$ 98,447	$ 244,650
General partner interest	(20,729)	(10,663)	(5,608)
Minority interest	(3,859)	(2,947)	(2,472)
Net income available to limited partners	$ 83,817	$ 84,837	$ 236,570
BASIC EARNINGS PER UNIT			
Numerator			
Net income available to limited partners	$ 83,817	$ 84,837	$ 236,570
Denominator			
Common units outstanding	183,779	119,820	96,633
Subordinated units outstanding	15,955	35,634	42,820
Class B special units outstanding	181		
Total	199,915	155,454	139,453
Basic earnings per unit			
Net income available to limited partners	$ 0.42	$ 0.55	$ 1.70
DILUTED EARNINGS PER UNIT			
Numerator			
Net income available to limited partners	$ 83,817	$ 84,837	$ 236,570
Denominator			
Common units outstanding	183,779	119,820	96,633
Subordinated units outstanding	15,955	35,634	42,820
Class A special units outstanding	5,808	21,036	31,334
Class B special units outstanding	181		
Incremental option units	644		
Total	206,367	176,490	170,787
Diluted Earnings per unit			
Net income available to limited partners	$ 0.41	$ 0.48	$ 1.39

14. RELATED PARTY TRANSACTIONS

Relationship with EPCO and its affiliates

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director (and Chairman of the Board of Directors) of our General Partner. In addition, the remaining executive and other officers of our General Partner are employees of EPCO, including O.S. Andras who is our President and Chief Executive Officer and a director of the General Partner. The principal business activity of the General Partner is to act as our managing partner.

Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to the common units and Class B special units held by 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, EPCO and Dan Duncan LLC, together, own 100% of our General Partner, which in turn owns a 2% general partner interest in us.

In addition, trust affiliates of EPCO (the 1998 Trust and 2000 Trust) owned 4,478,236 of our common units at December 31, 2003. Collectively, EPCO, Dan L. Duncan, the 1998 Trust and the 2000 Trust owned 54.5% of our partnership interests at December 31, 2003.

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 terms of the Administrative Services Agreement, EPCO agrees to:

- employ the personnel necessary to manage our business and affairs (through our General Partner);
- employ the operating personnel involved in our business for which we reimburse EPCO (based upon EPCO s actual salary and related fringe benefits cost);
- 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;
- grant us an irrevocable, non-exclusive worldwide license to all of the EPCO trademarks and trade names used in our business; and
- sublease to us all of the equipment which it holds pursuant to operating leases relating to an isomerization unit, a deisobutanizer tower, two cogeneration units and approximately 100 railcars for one dollar per year and to assign to us its purchase option under such leases to us (the retained leases). EPCO remains liable for the cash lease payments associated with these assets.

Operating costs and expenses (as shown in our Statements of Consolidated Operations) treat the lease 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. We notified the lessor of the isomerization unit associated with the retained leases of our intent to exercise the purchase option relating to this equipment in 2004. Under the terms of the lease agreement for the isomerization unit, we have the option to purchase the equipment at the lesser of fair value or $23.1 million. 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 $2.8 million would be payable in 2004, $2.3 million 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) include the costs we pay EPCO for administrative support. Through December 31, 2003, 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. During 2003, we paid $17.9 million in such fees to EPCO.

- 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 did not materially exceed the capped amounts for the years ended December 31, 2002 and 2001. 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 a fixed Administrative Services Fee and to provide that we will 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.

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, 2002 and 2001, we paid EPCO $0.8 million, $0.8 million and $0.9 million for such services, respectively. 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.

The following table summarizes our various related party transactions with EPCO for the periods indicated:

	For Year Ended December 31,		
	2003	**2002**	**2001**
Revenues from consolidated operations			
EPCO and subsidiaries	$ 4,241	$ 3,630	$ 5,439
Operating costs and expenses			
EPCO and subsidiaries	149,626	103,210	62,919
Selling, general and administrative expenses			
Base fees payable under EPCO Agreement	17,940	16,638	15,125
Other EPCO compensation reimbursement	9,578	7,566	4,824
Other expenses paid by EPCO on our behalf	442	n/a	n/a

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At December 31, 2003, Shell owned approximately 18.4% of our partnership interests. Shell sold its 30.0% interest in our General Partner to an affiliate of EPCO in September 2003.

Our largest customer is Shell. For the years ended December 31, 2003, 2002 and 2001, they accounted for 5.5%, 7.9% and 10.6%, 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 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.

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. This contract was amended effective March 1, 2003. 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 NGL stream 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.

As part of our natural gas processing obligations under this contract, we reimburse Shell for the energy value of (i) the NGLs we extract from the natural gas stream and (ii) the natural gas we remove from the stream and consume as fuel. This energy value is referred to as plant thermal reduction (PTR) and is based on the energy content of the natural gas taken out of the stream (measured in Btus). The amended contract contains a mechanism (termed Consideration Adjustment Outside of Normal Operations or CAONO) to adjust the value of the PTR we reimburse to Shell. The CAONO, in effect, protects us from processing Shell s natural gas at an economic loss when the value of the NGLs we extract is less than the sum of the cost of the PTR reimbursement, operating costs of the gas processing facility and other costs such as NGL fractionation and pipeline fees.

In general, the CAONO adjustment requires the comparison of our average net gas processing margin to an upper and lower limit (all as defined within the agreement). If our average net processing margin is below the lower limit, the PTR reimbursement payable to Shell is decreased by the product of the absolute value of the difference between our average net processing margin and the specified lower limit multiplied by the volume of NGLs extracted. To the extent our average net processing margin is higher than the upper limit , the PTR reimbursement payable to Shell is increased by the product of the difference between the average net gas processing margin and the specified upper limit multiplied by the volume of NGLs extracted. The underlying purpose of the CAONO mechanism is to provide Shell with relative assurance that its gas will continue to be processed during periods when natural gas prices are high relative to NGL prices (times when we would normally choose not to process a producer s natural gas stream) while continuing to protect us from processing Shell s gas at an economic loss.

The following table summarizes our various related party transactions with Shell for the periods indicated:

	For Year Ended December 31,		
	2003	**2002**	**2001**
Revenues from consolidated operations			
Shell	$293,109	$282,820	$333,333
Operating costs and expenses			
Shell	607,277	531,712	705,440

We have completed a number of business acquisitions and asset purchases involving Shell since 1999. Among these transactions were:

- the acquisition of TNGL s natural gas processing and related businesses in 1999 for approximately $528.8 million (this purchase price includes both the $166 million in cash we paid to Shell and the value of the 41,000,000 Class A special units granted to Shell in connection with this acquisition);
- the purchase of the Lou-Tex Propylene pipeline for $100 million in 2000; and
- the acquisition of Acadian Gas in 2001 for $243.7 million.

Shell is also a partner with us in our Gulf of Mexico natural gas pipeline investments. We also lease from Shell its 45.4% interest in our Splitter I propylene fractionation facility.

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. We have also furnished $1.3 million in letters of credit on behalf of Evangeline.

We pay Dixie transportation fees for propane movements on their system initiated by our NGL marketing activities.

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.

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 30, 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 MTBE movements on our HSC pipeline and fractionation revenues for reprocessing mixed feedstock streams generated by BEF.

The following table summarizes our related party transactions with unconsolidated affiliates for the periods indicated:

	For Year Ended December 31,		
	2003	**2002**	**2001**
Revenues from consolidated operations			
Evangeline	$212,662	$131,635	$117,283
BEF (1)	32,765	50,494	45,778
Promix	19,575	12,697	8,952
EPIK (2)	58	259	297
Other unconsolidated affiliates	1,834	1,182	1,374
Operating costs and expenses			
Dixie	11,296	12,184	12,695
BEF (1)	6,646	9,794	8,073
Promix	17,465	18,408	12,676
EPIK (2)	6,607	19,788	7,438
Other unconsolidated affiliates	1,738	483	193

(1) Amounts shown in the table reflect the period of time that we accounted for our investment in BEF using the equity-method. BEF became a consolidated subsidiary of ours on September 30, 2003. For additional information regarding our prior equity investment in BEF, please read Note 7.

(2) Amounts shown in the table reflect the period of time that we accounted for our investment in EPIK using the equity-method. EPIK became a consolidated subsidiary of ours on March 1, 2003. For additional information regarding our prior equity investment in EPIK, please read Note 7.

As part of Other Income and Expense as shown in our Statements of Consolidated Operations and Comprehensive Income, we record dividend income from our investment in VESCO.

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 option grants has been recognized in our Statements of Consolidated Operations and Comprehensive Income. Any special distributions (as described in the following information) 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.

Through December 31, 2003, our responsibility for reimbursing EPCO for the cash outlay it incurred when these options were exercised was as follows:

We paid EPCO for the costs attributable to unit option awards granted to operations personnel it employs on our behalf. Our payment to EPCO is in the form of a special distribution.
We paid 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. Our payment to EPCO is in the form of a special distribution.
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.

1. 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 (see Note 14). 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.

2. If EPCO requested us to provide units to satisfy its obligations to these employees, we reimbursed EPCO in the form of a special distribution.

Effective January 1, 2004, the Administrative Services Agreement was amended to provide that we will reimburse EPCO for all costs (including those related to unit options) related to administrative support personnel regardless of whether the costs are related to pre-expansion or expansion personnel who work on our behalf. Our obligation regarding operations-related personnel remains the same. Under the amended agreement, our payment to EPCO for both administrative and operations personnel who exercise unit options will be in the form of a special distribution regardless of how the option liability is satisfied (i.e., through open market purchases or units acquired from EPCO affiliates or us). During 2003, we made $2.7 million of special cash distributions to EPCO to meet our obligations under EPCO s 1998 Plan.

Summary of 1998 Plan activity

EPCO s 1998 Plan is used to issue unit option awards to the three categories of employees discussed previously in this Note 15. 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, 2001	1,931,758	$ 6.66
Granted	1,050,000	16.41
Exercised	(760,118)	4.94
Forfeited	(20,000)	9.00
Outstanding at December 31, 2001	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
Options exercisable at:		
December 31, 2001	221,640	$ 1.65
December 31, 2002	711,078	$ 7.83
December 31, 2003	509,000	$ 9.68

				Options Exercisable at December 31, 2003	
Range of Strike Prices	Options outstanding at December 31, 2003	Weighted-Average Remaining Contractual Life (in Years)	Weighted Average Strike Price	Number Exercisable at December 31, 2003	Weighted Average Strike Price
$7.75 - $9.00	339,000	5.75	$ 8.63	339,000	$ 8.63
$11.63 - $12.56	210,000	6.83	11.91	170,000	11.76
$15.93 - $17.63	925,000	7.10	16.12		
$21.15 - $24.73	464,000	8.26	23.30		
	1,938,000			509,000	

The weighted-average fair value of options granted during 2003, 2002 and 2001 was $2.17, $3.12 and $1.97 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, 2003, NGL and petrochemical volumes aggregating

16.4 million barrels were due to be redelivered to their owners along with 393 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, 2003, there were 1,938,000 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 $16.07 per common unit. At December 31, 2003, 509,000 of these unit options were exercisable. An additional 1,030,000, 374,000 and 25,000 of these unit options will be exercisable in 2004, 2005 and 2006, respectively. Effective January 1, 2004, 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

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 following table shows our scheduled future maturities of long-term debt for the periods indicated. See Note 9 for a description of these debt obligations.

Operating lease commitments. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. The following table shows the minimum lease payment obligations under our third-party operating leases with terms in excess of one year for the periods indicated.

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 obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The following table shows our volume commitments and estimated payment obligations under these contracts for the periods indicated. 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, 2003 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 following 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 following table shows these combined amounts for the periods indicated:

Contractual Obligations	Total	2004	2005	2006	2007	2008	Thereafter
	Payment or Settlement due by Period						
Long-term debt, including							
current maturities	$ 2,144,000	$ 240,000	$ 550,000				$ 1,354,000
Operating lease obligations	$ 47,197	$ 8,928	$ 4,290	$ 3,786	$ 3,679	$ 3,451	$ 23,063
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 1,079,876	$ 150,620	$ 117,501	$ 115,965	$ 115,965	$ 115,965	$ 463,860
NGLs	$ 131,904	$ 15,745	$ 8,935	$ 8,935	$ 8,935	$ 8,935	$ 80,419
Petrochemicals	$ 1,149,987	$ 425,971	$ 373,174	$ 327,171	$ 23,671		
Other	$ 75,455	$ 45,996	$ 21,682	$ 2,207	$ 2,207	$ 2,207	$ 1,156
Underlying major volume commitments:							
Natural gas (in Bbtus)	164,032	23,602	17,790	17,520	17,520	17,520	70,080
NGLs (in MBbls)	5,333	578	366	366	366	366	3,291
Petrochemicals (in MBbls)	36,892	13,696	11,952	10,490	754		
Service payment commitments	$ 552	$ 382	$ 85	$ 85			
Capital expenditure commitments	$ 4,003	$ 4,003					

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 $12.1 million for 2004, $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. We notified the lessor of the isomerization unit associated with the retained leases of our intent to exercise the purchase option relating to this equipment in 2004. Under the terms of the lease agreement for the isomerization unit, we have the option to purchase the equipment at the lesser of fair value or $23.1 million. 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 $2.8 million would be payable in 2004, $2.3 million in 2008 and $3.1 million in 2016.

Third-party lease and rental expense included in operating income for the years ended December 31, 2003, 2002 and 2001 was approximately $17.8 million, $16.4 million and $13.0 million, respectively.

Litigation

We are sometimes named as a defendant in litigation relating to our normal business operations. 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.

17. SUPPLEMENTAL CASH FLOWS DISCLOSURE

The net effect of changes in operating assets and liabilities is as follows:

	For Year Ended December 31,		
	2003	2002	2001
(Increase) decrease in:			
Accounts and notes receivable	$ (54,388)	$ (127,365)	$ 231,532
Inventories	49,932	(84,254)	11,048
Prepaid and other current assets	11,073	15,340	(26,427)
Other assets	(226)	(3,322)	162
Increase (decrease) in:			
Accounts payable	(6,720)	23,901	(82,075)
Accrued gas payable	128,050	262,527	(178,102)
Accrued expenses	(16,677)	7,884	(1,576)
Accrued interest	15,012	5,369	14,234
Other current liabilities	(4,196)	(6,921)	3,073
Other liabilities	(972)	(504)	(9,012)
Net effect of changes in operating accounts	$ 120,888	$ 92,655	$ (37,143)
Cash payments for interest, net of $1,595, $1,083 and $2,946 capitalized in 2003, 2002 and 2001, respectively	$ 112,712	$ 82,535	$ 37,536
Cash payments for federal and state income taxes	$ 453	n/a	n/a

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 been previously accounted for using the equity-method (see Note 4) . 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. During 2001, we acquired Acadian Gas from Shell. These transactions and events over the last three years affected various balance sheet categories summarized as follows:

	For Year Ended December 31,		
	2003	2002	2001
Current assets	$ 24,960	$ 53,287	$ 83,123
Property, plant and equipment	131,452	1,507,243	225,169
Investments in unconsolidated affiliates	(57,172)	7,550	2,723
Intangible assets	4,057	92,356	
Goodwill	880	73,691	
Deferred tax asset		17,307	
Other assets	3,208	2,699	
Current liabilities	(32,140)	(17,747)	(83,890)
Long-term debt		(60,000)	
Other liabilities	(6,063)	(90)	(1,460)
Minority interest	(31,834)	(55,569)	
Total	$ 37,348	$ 1,620,727	$ 225,665

We record various financial instruments relating to commodity positions and interest rate hedging activities at their respective fair values using mark-to-market accounting. The amount for 2003 was negligible. 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. During 2001, we recognized a net $5.6 million in non-cash mark-to-market increases in the fair value of our financial instruments portfolio.

During 2003 and 2002, we acquired certain NGL-related contracts related to our ability to take delivery of purity NGL products and mixed NGLs from VESCO at a lower cost than otherwise would have been incurred. Of the $6.6 million value of this intangible asset, $2.6 million was reclassified from construction-in-progress during 2002 and $4.0 million represents the actual cash payments made to the third-party during 2003 and 2002. The prior expenditures recorded as construction-in-progress were reclassified due to the direct linkage between these expenditures and the successful negotiation of the Venice contracts.

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 transactions made on the NYMEX exchange. The restricted cash balance at December 31, 2003 and 2002 was $13.9 million and $8.8 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, primarily within our NGL Pipelines & Services segment. In general, the types of risks we attempt to hedge are those relating to the variability of future earnings and cash flows caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation methodologies. 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.

Commodity financial instruments

The prices of natural gas, NGLs, petrochemical products and MTBE 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 our NGL Pipelines & Services segment 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 certain anticipated transactions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

We do not hedge our exposure related to MTBE price risks. In addition, we generally do not hedge risks associated with the petrochemical marketing activities that are also part of our Petrochemical Services segment. In our Onshore Natural Gas Pipelines & Services segment, we do utilize a limited number of commodity financial instruments to manage the price Acadian Gas charges certain of its customers for natural gas.

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 the General Partner. We 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. The General Partner oversees our 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.

Our commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133 because of ineffectiveness. A financial instrument is generally regarded as effective when changes in its fair value almost fully offset changes in the fair value of the hedged item throughout the term of the instrument. Due to the complex nature of risks we attempt to hedge, our commodity financial instruments have generally not qualified as effective hedges under SFAS No. 133. As a result, changes in the fair value of these positions are recorded on the balance sheet and in earnings through mark-to-market accounting. Mark-to-market accounting results in a degree of non-cash earnings volatility that is dependent upon changes in the commodity prices underlying these financial instruments. Even though these financial instruments may not qualify for hedge accounting treatment under SFAS No. 133, we view such contracts as hedges since this was the intent when we entered into such positions. Upon entering into such positions, our expectation is that the economic performance of these instruments will mitigate (or offset) the commodity risk being addressed. The specific accounting for these contracts, however, is consistent with the requirements of SFAS No. 133.

At December 31, 2003, we had open commodity financial instruments that will settle at different dates through December 2004. We routinely review our outstanding commodity financial instruments in light of current market conditions. If market conditions warrant, some 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 hedge to which the closed instrument relates.

During 2003, we recognized a loss of $0.6 million from our commodity hedging activities that was recorded as an increase in our operating costs and expenses in the Statements of Consolidated Operations. Of the loss recognized in 2003, $0.8 million loss is related to commodity hedging activities associated with natural gas purchases within the Onshore Natural Gas Pipelines & Services segment offset by a $0.2 million gain from commodity hedging activities associated with the hedging of NGL production within the NGL Pipelines & Services segment.

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 in the Statements of Consolidated Operations. Of the loss recognized in 2002, $5.6 million is related to non-cash mark-to-market income recorded on open positions at December 31, 2001. During 2001, we posted income of $101.3 million from our commodity hedging activities, which served to reduce 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 prices 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 value of our equity NGL production. Throughout 2001, this strategy proved very successful to us (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 deteriorated 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 gas processing margins. Due to the inherent uncertainty that was controlling 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 failure of this strategy is the primary reason for the $51.3 million in commodity hedging losses we recorded during 2002.

We had a limited number of commodity financial instruments open at December 31, 2003 and 2002. The fair value of these open positions at December 31, 2003 and 2002 was an asset of $4 thousand and a liability of $26 thousand, respectively (both amounts based on market prices on these dates).

Interest rate hedging financial instruments

Our interest rate exposure results from variable-interest rate borrowings and fixed-interest rate borrowings (see Note 9). 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 to estimate the expected impact of changes in interest rates on our future cash flows. The General Partner oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

Interest rate swaps. We manage a portion of our interest rate risks by utilizing interest rate swaps. The objective of entering into interest rate swaps is to manage debt service costs by converting a portion of fixed-rate debt into variable-rate debt or a portion of variable-rate debt into fixed-rate debt. In general, an interest rate swap requires one party to pay a fixed-interest rate on a notional amount while the other party pays a floating-interest rate based on the same notional amount. The notional amount specified in an interest rate swap agreement does not represent exposure to credit loss. We monitor our positions and the credit ratings of counterparties. Management believes the risk of incurring a credit loss on these financial instruments is remote, and that if incurred, such losses would be immaterial. We believe that it is prudent to maintain an appropriate balance of variable-rate and fixed-rate debt.

At December 31, 2002, we had one interest rate swap outstanding having a notional amount of $54 million that extends through March 2010. Under this agreement, we exchanged a fixed-interest rate of 8.7% for a variable-interest rate that ranged from 1.8% to 4.5% during 2002 (the variable-interest rate we paid under this swap fluctuated over time depending on market conditions). The counterparty exercised its right to early termination of this swap in March 2003; therefore, only a minimal amount of income was recognized in 2003 from this financial instrument. We recognized income from our interest rate swaps of $0.9 million during 2002 compared to $13.2 million during 2001. This income is recorded as a reduction of interest expense in our Statements of Consolidated Operations. There were no interest rate swaps outstanding at December 31, 2003.

Treasury Locks. During the fourth quarter of 2002, we entered into seven treasury lock transactions. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific treasury security for an established period of time. A treasury lock purchaser is protected from a rise in the yield of the underlying treasury security during the lock period. Our treasury lock transactions carried an original maturity date of either January 31, 2003 or April 15, 2003. The purpose of these transactions was to hedge the underlying treasury interest rate associated with our anticipated issuance of debt in early 2003 to refinance the Mid-America and Seminole acquisitions. The notional amounts of these transactions totaled $550 million, with a total treasury lock rate of approximately 4%.

Our treasury lock transactions were accounted for as cash flow hedges. The fair value of these instruments at December 31, 2002 was a current liability of $3.8 million offset by a current asset of $0.2 million. The net $3.6 million non-cash mark-to-market liability was recorded as a component of comprehensive income on that date, with no impact to current earnings.

We elected to settle all of the treasury locks by early February 2003 in connection with our issuance of Senior Notes C and D (see Note 9). The settlement of these instruments resulted in our receipt of $5.4 million of cash. This amount was recorded as a gain in other comprehensive income during the first quarter of 2003 and represents the effective portion of the treasury locks.

Of the $5.4 million recorded in other comprehensive income during the first quarter of 2003, $4.0 million is attributable to our issuance of Senior Notes C and will be amortized to earnings as a reduction in interest expense over the 10-year term of this debt. The remaining $1.4 million is attributable to our issuance of Senior Notes D and will be amortized to earnings as a reduction in interest expense over the 10-year term of the anticipated transaction as required by SFAS No. 133. The amount reclassified from accumulated other comprehensive income to earnings during 2003 was $0.4 million. We expect to reclassify $0.4 million from other comprehensive income as a reduction to interest expense during 2004. With the settlement of the treasury locks, the $3.6 million non-cash mark-to-market liability recorded at December 31, 2002 was reclassified out of accumulated other comprehensive income in Partners   Equity to offset the current asset and liabilities we recorded at December 31, 2002 with no impact to earnings.

Future issues concerning SFAS No. 133

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

Fair value information

Cash and cash equivalents, accounts receivable, accounts payable and accrued expenses are carried at amounts which reasonably approximate their fair value at year end 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, 2003 and 2002:

	At December 31, 2003		At December 31, 2002	
Financial instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents	$ 44,317	$ 44,317	$ 22,568	$ 22,568
Accounts receivable	462,545	462,545	399,415	399,415
Commodity financial instruments (1)	358	358	513	513
Interest rate hedging financial instruments (2)			203	203
Financial liabilities:				
Accounts payable and accrued expenses	799,456	799,456	663,715	663,715
Fixed-rate debt (principal amount)	1,734,000	1,849,327	899,000	1,027,749
Variable-rate debt	410,000	410,000	1,346,000	1,346,000
Commodity financial instruments (1)	355	355	539	539
Interest rate hedging financial instruments (2)			3,766	3,766

(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.

19. SIGNIFICANT CONCENTRATIONS OF RISK

Nature of Operations

General. Our Company is subject to a number of risks inherent in the industry in which it operates, including fluctuating gas and product prices. Our financial condition and results of operations depend significantly on the demand for NGLs and the costs involved in their production. These NGL, natural gas and other related prices are subject to fluctuations in response to changes in supply, market uncertainty, weather and a variety of additional factors that are beyond our control.

In addition, we must obtain access to new natural gas volumes along the Gulf Coast of the United States for our processing business in order to maintain or increase gas plant processing levels to offset natural declines in field reserves. The number of wells drilled by third parties to obtain new volumes will depend on, among other factors, the price of gas and oil, the energy policy of the federal government and the availability of foreign oil and gas, none of which is in our control.

The products that we process, sell or transport are principally used as feedstocks in petrochemical manufacturing and in the production of motor gasoline and as fuel for residential and commercial heating. A reduction in demand for our products or services by industrial customers, whether because of general economic conditions, reduced demand for the end products made with our products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, governmental regulations affecting prices and production levels of natural gas or the content of motor gasoline or other reasons, could have a negative impact on our results of operation. A material decrease in natural gas production or crude oil refining, as a result of depressed commodity prices or otherwise, or a decrease in imports of mixed butanes, could result in a decline in volumes processed and sold by us.

MTBE. We own a 66.7% interest in BEF, which owns a facility that currently produces MTBE, a motor gasoline additive that enhances octane and is used in reformulated motor gasoline. We operate the facility, which is located within our Mont Belvieu complex.

The production of MTBE is 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.

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 BEF. It is possible, however, that MTBE manufacturers such as BEF could ultimately be added as defendants in such lawsuits or in new lawsuits. While we believe that we currently have adequate insurance to cover any adverse consequences resulting from our production of MTBE, we have been informed by our insurance carrier that upon renewal of our policy in April 2004, MTBE related claims may be excluded from the scope of our insurance coverage.

As a result of these developments, we are currently 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. The modification project is expected to be completed during the third quarter of 2004 at a total cost of approximately $30 million. The facility will continue to produce MTBE as market conditions warrant and will be capable of producing either MTBE or iso-octane once the plant modifications are complete. Depending on the outcome of various factors (including pending federal legislation) the facility may be further modified in the future to produce alkylate.

As noted above, MTBE demand is primarily linked to reformulated motor gasoline requirements in certain urban areas of the United States designated as carbon monoxide and ozone non-attainment areas by the federal Clean Air Act Amendments of 1990. Motor gasoline demand in turn is affected by many factors, including the price of motor gasoline (which is generally dependent upon crude oil prices) and overall economic conditions. Sun is obligated to purchase all of BEF s MTBE production at spot-market related prices through September 2004. Sun uses the MTBE it purchases from BEF either (i) to satisfy its own reformulated gasoline blending requirements in the eastern United States markets it serves, or (ii) as a commodity offered for resale to others.

BEF is exposed to commodity price risk due to the market-pricing provisions of the Sun agreement. Traditionally, MTBE prices are stronger during the April to September period of each year, which corresponds with the summer driving season. Future MTBE prices will be influenced by the timing and extent of federal and state legislation to ban or limit the use of MTBE.

Credit risk

A substantial portion of our revenues are derived from various companies in the NGL and petrochemical industry, located in the United States. 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.

Counterparty risk

From time to time, we have credit risk with our counterparties in terms of settlement risk associated with its financial instruments (which includes accounts receivable). 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.

In December 2001, Enron Corp., or Enron , filed for protection under Chapter 11 of the U.S. Bankruptcy Code. Within our allowance for doubtful accounts is an $8.6 million reserve for amounts owed to us by Enron and its affiliates. Affiliates of Enron were our counterparty to various past financial instruments, which were guaranteed by Enron. The Enron amounts were unsecured and the amount that we may ultimately recover, if any, is not presently determinable.

20. SEGMENT INFORMATION

Operating segments are components of a business about which separate financial information is available. These components are regularly evaluated by the chief operating decision maker 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.

We have segregated our business activities into four distinct 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. Our segments are regularly evaluated by the CEO of our general partner in deciding how to allocate resources and in assessing performance.

We evaluate segment performance based on the segment gross operating margin. Segment gross operating margin 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 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. Segment 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. Segment gross operating margin 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 include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin (see Note 7). 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. 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.

Segment revenues and expenses include intrasegment and intrasegment transactions, which are generally based on transactions made at market-related rates. These transactions include, but are not limited to, the following types:

- NGL fractionation revenues from separating our mixed NGL inventories into distinct NGL products using our fractionation plants as directed by our NGL marketing activities (an intrasegment revenue of the NGL Pipelines & Services segment offset by an intrasegment expense of the NGL Pipelines & Services segment);
- Isomerization revenues received from charging our NGL marketing activities a toll processing fee to process inventories of mixed and normal butanes (an intersegment revenue of the Petrochemical Services segment offset by an intersegment expense of the NGL Pipelines & Services segment);
- Transfer sales of mixed NGLs retained under keepwhole or percent-of-liquids arrangements between our natural gas processing plants to our NGL marketing activities (an intrasegment revenue of the NGL Pipelines & Services segment offset by an intrasegment expense of the NGL Pipelines & Services segment); and
- Transfer sales of mixed NGLs retained under percent-of-liquids arrangements by our Norco NGL fractionator to our NGL marketing activities (an intrasegment revenue of the NGL Pipelines & Services segment offset by an intrasegment expense of the NGL Pipelines & Services segment).

Our consolidated revenues reflect the elimination of all material intercompany (both intersegment and intrasegment) transactions.

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.

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.

The Other non-segment category is presented in our segment reporting for financial reporting purposes only to show 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, which owns a 1.0% general partner interest in GulfTerra. Our investment in GulfTerra GP will be accounted for using the equity method until the completion of our merger with GulfTerra. 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.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

	For Year Ended December 31,		
	2003	2002	2001
Revenues [1]	$ 5,346,431	$ 3,584,783	$ 3,154,369
Less operating costs and expenses [1]	(5,046,777)	(3,382,839)	(2,862,582)
Add equity in income (loss) of unconsolidated affiliates [2]	(13,960)	35,253	25,358
Subtotal	285,694	237,197	317,145
Add: Depreciation and amortization in operating costs and expenses [3]	115,643	86,028	48,775
Retained lease expense, net in operating expenses allocable to us [4]	9,010	9,033	10,309
Retained lease expense, net in operating expenses allocable to our General Partner s minority interest in us [5]	84	92	105
Loss (gain) on sale of assets in operating costs and expenses [1]	(16)	(1)	(390)
Total segment gross operating margin	$ 410,415	$ 332,349	$ 375,944

(1) These amounts are comprised of both third party and related party totals as shown on our Statements of Consolidated Operations and Comprehensive Income.
(2) This amount is taken directly from our Statements of Consolidated Operations and Comprehensive Income.
(3) This amount is taken directly from the operating activities section of our Statements of Consolidated Cash Flows.
(4) This non-cash amount represents our share of the value of the operating leases contributed by EPCO to the Operating Partnership for which EPCO has retained the cash payment obligation (the retained leases , see Note 14). This amount is taken from the operating activities section (Operating lease expense paid by EPCO line item) of our Statements of Consolidated Cash Flows.
(5) This non-cash amount represents a minority interest holder s share of the value of the retained leases. This amount is a component of Contributions from minority interests as shown in the financing activities section of our Statements of Consolidated Cash Flows.

The following table reconciles consolidated operating income to total segment gross operating margin for the periods indicated (dollars in thousands):

	For Year Ended December 31,		
	2003	2002	2001
Operating income	$ 248,104	$ 194,307	$ 286,849
Adjustments to reconcile operating income to total gross operating margin:			
Depreciation and amortization in operating costs and expenses	115,643	86,028	48,775
Retained lease expense, net in operating costs and expenses	9,094	9,125	10,414
Loss (gain) on sale of assets in operating costs and expenses	(16)	(1)	(390)
Selling, general and administrative costs	37,590	42,890	30,296
Total segment gross operating margin	$ 410,415	$ 332,349	$ 375,944

Information by segment, together with reconciliations to the consolidated totals, is presented in the following table:

	Business Segments						
	Offshore Pipelines & 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, 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
Year ended December 31, 2001		220,087	2,151,748	270,078			2,641,913
Revenues from related parties:							
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
Year ended December 31, 2001		152,927	330,188	29,341			512,456
Intersegment and intrasegment revenues:							
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)	
Year ended December 31, 2001		1,942	827,900	102,831		(932,673)	
Total revenues:							
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
Year ended December 31, 2001		374,956	3,309,836	402,250		(932,673)	3,154,369
Equity income (loss) in unconsolidated affiliates:							
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
Year ended December 31, 2001	8,310	(145)	10,361	6,832			25,358
Gross operating margin by individual business segment and in total:							
Year ended December 31, 2003	5,561	18,345	310,631	75,931	(53)		410,415
Year ended December 31, 2002	10,535	22,109	181,884	117,821			332,349
Year ended December 31, 2001	8,311	11,679	258,625	97,329			375,944
Segment assets:							
At December 31, 2003		220,922	2,183,485	484,666		74,432	2,963,505
At December 31, 2002		225,392	2,092,217	443,993		49,237	2,810,839
Investments in and advances to unconsolidated affiliates:							
At December 31, 2003	127,605	2,519	190,682	22,006	424,947		767,759
At December 31, 2002	118,300	2,383	195,885	80,425			396,993
Intangible Assets:							
At December 31, 2003			215,072	53,821			268,893
At December 31, 2002			226,049	51,612			277,661
Goodwill:							
At December 31, 2003			8,737	73,690			82,427
At December 31, 2002			7,857	73,690			81,547

In general, our historical operating results and/or financial position have been affected by the following acquisitions since 2001:

the acquisition of a 50% interest in GulfTerra GP from El Paso in December 2003 for $425 million;
the Mid-America and Seminole pipeline systems from Williams in July 2002 for $1.2 billion;
a Mont Belvieu, Texas propylene fractionation business from Diamond-Koch in February 2002 for $239 million;
a Mont Belvieu, Texas NGL and petrochemical storage business from Diamond-Koch in January 2002 for $129.6 million;
the Acadian Gas pipeline system from Shell in April 2001 for $243.7 million; and
equity interests in four Gulf of Mexico natural gas pipelines from affiliates of El Paso in January 2001 for $113 million.

These acquisitions were accounted for as purchases and therefore operating results of these acquired entities are included in our financial results prospectively from the purchase date.

During 2002, we recognized a loss of $51.3 million from our NGL Pipelines & Services segment s commodity hedging activities that was recorded as an increase in our operating costs and expenses which reduced segment gross operating margin. During 2001, we posted income of $101.3 million from this segment s commodity hedging activities, which served to reduce operating costs and expenses and increase segment gross operating margin.

Due to a 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.

21. CONDENSED FINANCIAL INFORMATION OF OPERATING PARTNERSHIP

The Operating Partnership and its subsidiaries conduct substantially all of our business. We have no independent operations and no material assets outside of those of the Operating Partnership. In December 2003, we restructured our General Partner s ownership interest in us and our Operating Partnership from a 1% ownership 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.

The Operating Partnership has outstanding publicly traded debt securities consisting of its Senior Notes A, B, C and D. We act as guarantor of all of our Operating Partnership s consolidated debt obligations (including its publicly-traded debt securities), with the exception of the Seminole 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 the Operating Partnership s debt obligations is full and unconditional. For additional information regarding our consolidated debt obligations, see Note 9.

The number and dollar amount of reconciling items between our consolidated financial statements and those of our Operating Partnership are insignificant. The primary reconciling items between the consolidated balance sheet of the Operating Partnership and our consolidated balance sheet are the 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 minority interest differences are attributable to the General Partner s 1.0101% ownership of the Operating Partnership prior to December 2003.

The following tables show condensed financial information for the Operating Partnership for the periods and at the dates indicated:

Consolidated Balance Sheet Data:

	December 31, 2003	December 31, 2002
ASSETS		
Current assets	$ 687,530	$ 638,857
Property, plant and equipment, net	2,963,505	2,810,839
Investments in and advances to unconsolidated affiliates, net	767,759	396,993
Intangible assets, net	268,893	277,661
Goodwill	82,427	81,547
Deferred tax asset	10,437	15,846
Other assets	22,610	9,818
Total	$ 4,803,161	$ 4,231,561
LIABILITIES AND PARTNERS EQUITY		
Current liabilities	$ 1,093,747	$ 721,360
Long-term debt	1,899,548	2,231,463
Other long-term liabilities	14,081	7,666
Minority interest	89,216	59,336
Partners equity	1,706,569	1,211,736
Total	$ 4,803,161	$ 4,231,561
Total Operating Partnership debt obligations guaranteed by us	$ 2,114,000	$ 2,200,000

Consolidated Statements of Operations Data:

	For Year Ended December 31, 2003	2002	2001
Revenues	$ 5,346,431	$ 3,584,783	$ 3,154,369
Costs and expenses	5,083,701	3,425,503	2,893,394
Equity in income (loss) of unconsolidated affiliates	(13,960)	35,253	25,358
Operating income	248,770	194,533	286,333
Other income (expense)	(133,798)	(93,810)	(41,471)
Income before provision of income taxes and minority interest	114,972	100,723	244,862
Provision for income taxes	(5,293)	(1,634)	
Income before minority interest	109,679	99,089	244,862
Minority interest	(3,095)	(2,137)	(144)

	For Year Ended December 31,		
Net income	$ 106,584	$ 96,952	$ 244,718

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22. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table contains selected quarterly financial data for 2003 and 2002 (dollars in thousands, except per unit amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2002:				
Revenues	$ 662,054	$ 786,257	$ 943,313	$ 1,193,159
Operating income (loss)	(1,233) (1,2)	39,930 (2)	68,325 (2)	87,285 (2)
Net income (loss)	(17,203) (1)	22,320	34,850 (3)	55,533
Comprehensive income (loss)	(17,203) (1)	22,320	34,850 (3)	51,973
Net income (loss) per unit, basic	$ (0.13) (1)	$ 0.14	$ 0.20	$ 0.30
Net income (loss) per unit, diluted	$ (0.13) (1)	$ 0.11	$ 0.18	$ 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 (4)	66,102
Net income (loss)	40,505	33,105	(3,261) (4)	34,197
Comprehensive income (loss)	49,351	33,008	(3,360) (4)	34,097
Net income (loss) per unit, basic	$ 0.20	$ 0.15	$ (0.04) (4)	$ 0.13
Net income (loss) per unit, diluted	$ 0.19	$ 0.14	$ (0.04) (4)	$ 0.13

(1) We recorded an operating loss and net loss for the first quarter of 2002 primarily due to $45.1 million of commodity hedging losses within our NGL Pipelines & Services segment caused by an unexpected increase in natural gas prices. Overall, we recorded $51.3 million of such losses during 2002.

(2) Beginning in the first quarter of 2003, we reclassified certain expenses that had been a component of other expenses in our Statements of Consolidated Operations to operating expenses within our NGL Pipelines & Services segment. As a result of this reclassification, operating income was reduced by $129 thousand for the first quarter of 2002; $34 thousand for the second quarter of 2002; $31 thousand for the third quarter of 2002; and by $84 thousand for the fourth quarter of 2002. This reclassification had no effect on reported 2002 quarterly net income or loss, comprehensive income or loss, or earnings per unit amounts.

(3) Operating income, net income and comprehensive income beginning with the third quarter of 2002 increased as a result of our acquisition of interests in the Mid-America and Seminole pipelines in July 2002.

(4) Equity earnings from BEF for the third quarter of 2003 include a $22.5 million charge related to an asset impairment. 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					
2003	$ 21,196	$ 1,239	$ 71	$ (2,083)(1,3)	$ 20,423
2002	20,642	14	5,251 (1)	(4,711) (3)	21,196
2001	10,916	6,200 (1)	6,522 (2)	(2,996) (3)	20,642
Other current assets					
Additional credit reserve for Enron					
2002	4,305			(4,305) (1)	
2001			4,305 (1)		4,305
Other current liabilities					
Reserve for environmental liabilities					
2003	9				9
2002			102	(93)	9
Reserve for inventory gains and losses (5)					
2003	1,271	3,000		(1,571)	2,700
2002	2,029	500		(1,258)	1,271
2001	5,690	500		(4,161) (5)	2,029
Reserve for BEF turnaround accrual (6)					
2003			2,124 (4)	(111)	2,013
Other long-term liabilities					
Reserve for environmental liabilities					
2003	135		1,061	(63)	1,133
2002		45	90		135
Reserve for BEF turnaround accrual (6)					
2003			5,001(4)		5,001

The following explanations describe significant transactions affecting the amounts shown in the table above and on the preceding page:

(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 2001 as a result of accounts acquired in the Acadian Gas acquisition.

(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. A review of the reserve balance was performed in late 2001 and based upon its findings and estimated future losses, the reserve was lowered by $2.4 million.

(6) As noted in footnote 4 above, we began consolidating BEF s accounts with those of our own on September 30, 2003. Historically, BEF has used the accrue-in-advance method for its major maintenance costs. These reserves represent the short and long-term components of such estimates.

SECTION 4 REVISED SELECTED QUARTERLY BUSINESS SEGMENT FINANCIAL AND OPERATING INFORMATION

The following selected quarterly financial and operating information is presented to show investors and other interested parties how our segment results and related non-GAAP reconciliations would have appeared if the change in our business segments had occurred on January 1, 2003. For information regarding our new business segments, please read Note 20 of the Notes to Consolidated Financial Statements included under Section 3 of this Item 8.01. For information regarding the three and nine months ended September 30, 2004 and 2003, please read our quarterly report on Form 10-Q filed on November 9, 2004.

	Fiscal 2003				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Segment non-GAAP gross operating margin:					
Offshore pipelines & services	$ 1,494	$ 2,278	$ 1,648	$ 141	$ 5,561
Onshore natural gas pipelines & services	4,075	4,612	5,540	4,118	18,345
NGL pipelines & services	102,851	74,401	53,313	80,066	310,631
Petrochemical services	18,018	25,192	8,033	24,688	75,931
Non-segment other				(53)	(53)
Total non-GAAP gross operating margin	126,438	106,483	68,534	108,960	410,415
Adjustments to reconcile total non-GAAP gross operating margin to GAAP operating income:					
Depreciation and amortization in operating costs and expenses	(27,657)	(27,844)	(28,259)	(31,883)	(115,643)
Retained lease expense, net in operating costs and expenses	(2,274)	(2,274)	(2,273)	(2,273)	(9,094)
Gain (loss) on sale of assets in operating costs and expenses	(4)	36	35	(51)	16
Selling, general and administrative costs	(11,471)	(10,053)	(7,415)	(8,651)	(37,590)
GAAP consolidated operating income	$ 85,032	$ 66,348	$ 30,622	$ 66,102	$ 248,104

	Year-to-Date September 30, 2004			
	First Quarter	Second Quarter	Third Quarter	Total
Segment non-GAAP gross operating margin:				
Offshore pipelines & services	$ 982	$ 874	$ 720	$ 2,576
Onshore natural gas pipelines & services	5,599	6,143	7,186	18,928
NGL pipelines & services	89,734	58,109	83,851	231,694
Petrochemical services	24,053	31,191	35,524	90,768
Non-segment other	10,554	10,712	10,759	32,025
Total non-GAAP gross operating margin	130,922	107,029	138,040	375,991
Adjustments to reconcile total non-GAAP gross operating margin to GAAP operating income:				
Depreciation and amortization in operating costs and expenses	(30,520)	(31,715)	(32,439)	(94,674)
Retained lease expense, net in operating costs and expenses	(2,274)	(2,273)	(2,273)	(6,820)
Gain (loss) on sale of assets in operating costs and expenses	(98)	(17)	(43)	(158)
Selling, general and administrative costs	(9,466)	(7,087)	(10,076)	(26,629)
GAAP consolidated operating income	$ 88,564	$ 65,937	$ 93,209	$ 247,710

	Fiscal 2003				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Offshore pipelines & services, net:					
Natural gas transportation volumes (BBtu/d)	479	437	438	378	433
Onshore natural gas pipelines & services, net:					
Natural gas transportation volumes (BBtu/d)	555	596	619	627	599
NGL pipelines & services, net:					
NGL transportation volumes (MBPD)	1,263	1,234	1,323	1,281	1,275
NGL fractionation volumes (MBPD)	235	201	233	241	227
Equity NGL production (MBPD)	47	39	41	44	43
Fee-based natural gas processing (MMcf/d)	65	160	224	324	194
Petrochemical services, net:					
Butane isomerization volumes (MBPD)	80	82	77	70	77
Propylene fractionation volumes (MBPD)	60	58	54	56	57
Octane additive production volumes (MBPD)	3	3	4	7	4
Petrochemical transportation volumes (MBPD)	50	61	77	76	68
Total, net:					
NGL and petrochemical transportation volumes (MBPD)	1,313	1,295	1,400	1,357	1,343
Natural gas transportation volumes (BBtu/d)	1,034	1,033	1,058	1,005	1,032
Equivalent transportation volumes (MBPD)	1,585	1,566	1,678	1,621	1,615

	Year-to-Date September 30, 2004			
	First Quarter	Second Quarter	Third Quarter	Total
Offshore pipelines & services, net:				
Natural gas transportation volumes (BBtu/d)	429	448	393	423
Onshore natural gas pipelines & services, net:				
Natural gas transportation volumes (BBtu/d)	646	620	685	650
NGL pipelines & services, net:				
NGL transportation volumes (MBPD)	1,368	1,255	1,450	1,358
NGL fractionation volumes (MBPD)	229	237	239	235
Equity NGL production (MBPD)	48	45	47	47
Fee-based natural gas processing (MMcf/d)	362	1,248	1,217	944
Petrochemical services, net:				
Butane isomerization volumes (MBPD)	60	78	82	73
Propylene fractionation volumes (MBPD)	54	60	58	58
Octane additive production volumes (MBPD)	5	10	12	9
Petrochemical transportation volumes (MBPD)	63	76	76	73
Total, net:				
NGL and petrochemical transportation volumes (MBPD)	1,431	1,331	1,527	1,430
Natural gas transportation volumes (BBtu/d)	1,075	1,068	1,079	1,074
Equivalent transportation volumes (MBPD)	1,714	1,612	1,811	1,713

Item 9.01. Financial Statements and Exhibits.

(c) Exhibits.

Exhibit No.	Description
23.1	Consent of Deloitte & Touche LLP.

SIGNATURES

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

ENTERPRISE PRODUCTS PARTNERS L.P.

By: Enterprise Products GP, LLC,
its General Partner

Date: December 6, 2004

By: /s/ Michael J. Knesek

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

INDEX TO EXHIBITS

Exhibit No.	Description
23.1	Consent of Deloitte & Touche LLP.