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

FORM 10-K/A

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934 For the fiscal year ended December 31, 2002.

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ________ to ________.

Commission file numbers: 1-14323
333-93239-01

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS OPERATING L.P.
(Exact name of registrants as specified in their charters)

DELAWARE	76-0568219
DELAWARE	76-0568220
(State or other jurisdiction of incorporation of organization)	(I.R.S. Employer Identification No.)

2727 NORTH LOOP WEST, HOUSTON, TEXAS 77008-1037
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (713) 880-6500

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

Title of each class	Name of each exchange on which registered
Common Units	New York Stock Exchange

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [X] No [ ]

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).
Yes [X] No [ ]

The aggregate market value of the Common Units of Enterprise Products Partners L.P. ("EPD") held by non-affiliates at June 28, 2002, based on the closing price of such equity securities in the daily composite list for transactions on the New York Stock Exchange on June 28, 2002, was approximately $292.2 million. This figure assumes that Duncan Family 1998 Trust, Duncan Family 2000 Trust, EPOLP 1999 Grantor Trust, Shell US Gas & Power LLC, and the directors and executive officers of Enterprise Products GP, LLC (the "General Partner") are affiliates of EPD.

There were 156,357,266 Common Units, 32,114,804 Subordinated Units and 10,000,000 Special Units of EPD outstanding at March 1, 2003. No common equity securities of Enterprise Products Operating L.P. are held by non-affiliates. Enterprise Products Operating L.P. is owned 98.9899% by its parent, EPD, and 1.0101% by the General Partner.

EXPLANATORY NOTE

This report constitutes a combined report for Enterprise Products Partners L.P. (the "Company")(Commission File No. 1-14323) and its 98.9899% owned subsidiary, Enterprise Products Operating L.P. (the "Operating Partnership")(Commission File No. 333-93239-01). Since the Operating Partnership owns substantially all of the Company's consolidated assets and conducts substantially all of the Company's business and operations, the information within this annual report on Form 10-K constitutes combined information for the Company and the Operating Partnership except for the following:

- Part I, Item 4
- Part II, Items 5, 6 and 8
- Part III, Item 12 (to the extent this section addresses Unitholder matters)
- Sarbanes-Oxley Section 302 Certifications

We are filing this Form 10-K/A in response to comments received from the Securities and Exchange Commission regarding our annual report on Form 10-K for the fiscal year ended December 31, 2002 that was originally filed on March 31, 2003 (the "Original Filing"). Specifically, we have amended the following sections of this annual report:

- Items 1 and 2. Business and Properties -- Recent Strategic Acquisitions, page 5: We have added a more precise cross reference to our financial statement footnote regarding business acquisitions.
- Item 3. Legal Proceedings, page 30: We have deleted the sentence, "EPCO has indemnified us against any litigation that was pending at the date of our formation in April 1998."
- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation -- Other Items -- SEC review, page 55: We have deleted the section titled "SEC review" since the Commission has now completed its review of our filings and has furnished us with final comments which are being incorporated into this amended annual report on Form 10-K.
- Item 13. Certain Relationships and Related Transactions -- Relationship with EPCO and affiliates -- EPCO Agreement, page 69: Under the section titled "EPCO Agreement," we have deleted the fifth bullet point referring to EPCO's agreeing to "indemnify us against any losses resulting from certain lawsuits."
- Item 13. Certain Relationships and Related Transactions, pages 70 and 72: We have inserted language noting that the dollar amounts shown in the tables are in thousands.
- Item 8. Financial Statements and Supplementary Data -- Commitments and Contingencies footnote of both registrants, pages F-40 and F-86: As with our change to page 30, we have revised the language to exclude references regarding EPCO's indemnification of litigation outstanding at our initial public offering.

This report continues to speak as of the date of the Original Filing, and we have not updated the disclosure in this report to speak as of a later date. All information contained in this report and the Original Filing is subject to updating and supplementing as provided in our periodic reports filed with the Securities and Exchange Commission.

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS OPERATING L.P.

TABLE OF CONTENTS

GLOSSARY

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

Acadian Gas	Acadian Gas, LLC and subsidiaries, acquired from Shell in April 2001
Accum. OCI	Accumulated Other Comprehensive Income
Asset platform	For a discussion of our "asset platform" please read "Business and Properties--General" beginning on page 1 of this annual report.
Basell	Basell polyolefins and affiliates
Baytank	Odjfell Terminals (Houston) LP
BBtus	Billion British thermal units, a measure of heating value
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
BEF	Belvieu Environmental Fuels, an equity investment of EPOLP
Belle Rose	Belle Rose NGL Pipeline LLC, an equity investment of EPOLP
BP	BP PLC and affiliates
BPD	Barrels per day
BRF	Baton Rouge Fractionators LLC, an equity investment of EPOLP
BRPC	Baton Rouge Propylene Concentrator, LLC, an equity investment of EPOLP
Burlington	Burlington Resources Inc. and affiliates
CEO	Chief Executive Officer
CFO	Chief Financial Officer
ChevronPhillips	ChevronPhillips Chemical Company L.P. and affiliates
ChevronTexaco	ChevronTexaco Corp., its subsidiaries and affiliates
CMAI	Chemical Market Associates, Inc.
Cogeneration	Cogeneration is the simultaneous production of electricity and heat using a single fuel such as natural gas.
Company	Enterprise Products Partners L.P. and its consolidated subsidiaries, including the Operating Partnership
ConocoPhillips	ConocoPhillips Petroleum Company and affiliates
CornerStone	CornerStone Propane Partners, L.P. and affiliates
CPG	Cents per gallon
Deepwater	Deepwater refers to oil and gas production areas located at depths of 1,000 feet or more such as those found in the Gulf of Mexico.
Devon Energy	Devon Energy Corporation, its subsidiaries and affiliates
Diamond-Koch	Refers to affiliates of Valero Energy Corporation and Koch Industries, Inc.
DIB	Deisobutanizer
Dixie	Dixie Pipeline Company, an equity investment of EPOLP
Duke	Duke Energy Corporation and its affiliates
El Paso	El Paso Corporation, its subsidiaries and affiliates
E-Oaktree	E-Oaktree, LLC, a subsidiary of the Company of whom 98% of its membership interests were acquired by us from affiliates of Williams in July 2002
EPA	Environmental Protection Agency
EPCO	Enterprise Products Company, an affiliate of the Company and our ultimate parent company (including its affiliates)
EPIK	EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively, an equity investment of EPOLP
EPOLP	Enterprise Products Operating L.P., the operating subsidiary of the Company (also referred to as the "Operating Partnership")
EPU	Earnings per Unit
Equistar	A joint venture of Lyondell Chemical Company and Millennium Chemicals, Inc.
Evangeline	Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively, an equity investment of EPOLP
FASB	Financial Accounting Standards Board

Feedstock	A raw material required for an industrial process such as in petrochemical manufacturing
FERC	Federal Energy Regulatory Commission
Forward sales contracts	The sale of a commodity or other product in a current period for delivery in a future period.
Fractionation	For a discussion of our Fractionation segment, please read "The Company's Operations--Fractionation" beginning on page 14 of this annual report.
FTC	U.S. Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States of America
General Partner	Enterprise Products GP, LLC, the General Partner of the Company and the Operating Partnership
HSC	Denotes our Houston Ship Channel pipeline system
ICA	Interstate Commerce Act
Isomerization	For a discussion of the isomerization process, please read "The Company's Operations -- Fractionation -- Isomerization" beginning on page 17 of this annual report.
IPO	Refers to our initial public offering in July 1998
Kinder Morgan	Kinder Morgan Operating LP "A"
La Porte	La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively, an equity investment of EPOLP
LIBOR	London interbank offered rate
Mapletree	Mapletree, LLC, a subsidiary of the Company of whom 98% of its membership interests were acquired by us from affiliates of Williams in July 2002
MBA	Mont Belvieu Associates, see "MBA acquisition" below
MBA acquisition	Refers to the acquisition of Mont Belvieu Associates' remaining interest in the Mont Belvieu NGL fractionation facility in 1999
MBFC	Mississippi Business Finance Corporation
MBPD	Thousand barrels per day
Mid-America	Mid-America Pipeline Company, LLC
Midstream Energy Assets	The intermediate segments of the energy industry downstream of oil and gas production and upstream of end user consumption. These segments provide services to producers and consumers of energy. These services generally include but are not limited to natural gas gathering, processing and wholesale marketing and NGL fractionation, transportation and storage.
MMcf/d	Million cubic feet per day
MMBbls	Millions of barrels
MMBtu/d	Million British thermal units per day, a measure of heating value
MMBtus	Million British thermal units, a measure of heating value
Mont Belvieu	Mont Belvieu, Texas
Moody's	Moody's Investors Service
MTBE	Methyl tertiary butyl ether
Natural gas processing	For a discussion of our natural gas processing business, please read "The Company's Operations -- Processing" beginning on page 20 of this annual report.
Nemo	Nemo Gathering Company, LLC, an equity investment of EPOLP
Neptune	Neptune Pipeline Company LLC, an equity investment of EPOLP
NGL or NGLs	Natural gas liquid(s)
NGL marketing activities	For a discussion of our NGL marketing activities, please read "The Company's Operations--Processing" beginning on page 20 of this annual report.
NYSE	New York Stock Exchange
Ocean Breeze	Ocean Breeze Pipeline Company, LLC, an equity investment of EPOLP (merged into Neptune during fourth quarter of 2001)
OPIS	Oil Price Information Service
Operating Partnership	Enterprise Products Operating L.P. and its subsidiaries

OTC	Olefins Terminal Corporation, an equity investment of the Company
Petrochemical marketing	For a discussion of our petrochemical marketing activities, please read "The Company's Operations--Fractionation--Propylene fractionation" beginning on page 18 of this annual report.
Promix	K/D/S Promix LLC, an equity investment of EPOLP
SEC	U.S. Securities and Exchange Commission
Seminole	Seminole Pipeline Company
SFAS	Statement of Financial Accounting Standards issued by the FASB
Shell	Shell Oil Company, its subsidiaries and affiliates
Splitter III	Refers to the propylene fractionation facility we acquired from Diamond-Koch
Spot market	Refers to a market where buyers and sellers consummate routine transactions where performance by both parties is short-term in nature and prices are based on market conditions at the time the transaction is executed. For a discussion of "spot market" transactions, please read "The Company's Operations--Fractionation--Propylene fractionation" beginning on page 18 of this annual report.
S&P	Standard & Poor's Rating Services
Starfish	Starfish Pipeline Company LLC, an equity investment of EPOLP
Straddle plants	A natural gas processing facility situated on a pipeline that is the sole inlet and outlet for the processing facility
Throughput	Refers to the physical movement of volumes through a pipeline
TNGL acquisition	Refers to the acquisition of Tejas Natural Gas Liquids, LLC, an affiliate of Shell, in 1999
Tri-States	Tri-States NGL Pipeline LLC, an equity investment of EPOLP
VESCO	Venice Energy Services Company, LLC, a cost method investment of EPOLP
Williams	The Williams Companies, Inc. and subsidiaries
Wilprise	Wilprise Pipeline Company, LLC, an equity investment of EPOLP
1998 Trust	Duncan Family 1998 Trust (formerly Enterprise Products 1998 Unit Option Plan Trust), an affiliate of EPCO
1999 Trust	EPOLP 1999 Grantor Trust, a subsidiary of EPOLP
2000 Trust	Duncan Family 2000 Trust (formerly Enterprise Products 2000 Rabbi Trust), an affiliate of EPCO

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

GENERAL

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 98.9899% 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 1.0% interest in us and a 1.0101% interest in our Operating Partnership. 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 EPCO Agreement. For a discussion of the EPCO Agreement, please read Item 13 of this annual report. 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. Our principal executive offices are located at 2727 North Loop West, Houston, Texas 77008-1038 and our telephone number is 713-880-6500.

We are a leading North American midstream energy company that provides a wide range of services to producers and consumers of natural gas and natural gas liquids, or NGLs. 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 asset platform comprises the only integrated natural gas and NGL transportation, fractionation, processing, storage and import/export network in North America. We provide integrated services to our customers and generate fee-based cash flow from multiple sources along our natural gas and NGL "value chain." We have provided definitions in the Glossary for some of the industry terms, names of companies and other abbreviations used in this document. With respect to the industry terms, we have provided the location in the document where you will find a more complete explanation of each industry term. Our 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 NGL and petrochemical products we produce and/or purchase for resale.

For a complete description of our natural gas processing activities, please refer to the business segment discussion titled "Processing" on page 20. For information regarding our fractionation and isomerization activities, please see the section titled "Fractionation" on page 14. 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 annual report reflect the Unit split, unless otherwise indicated.

BUSINESS STRATEGY

Our business strategy is to:

- capitalize on expected increases in natural gas and NGL production resulting from development activities in the deepwater and continental shelf areas of the Gulf of Mexico and the Rocky Mountain region;

- develop and invest in joint venture projects with strategic partners that will provide the raw materials for these projects or purchase the projects' end products;

- expand our asset base through accretive acquisitions of complementary midstream energy assets; and

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

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 objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. 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 review our "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:

We have significant leverage that may restrict our future financial and operating flexibility.

Our leverage is significant in relation to our partners' capital. At December 31, 2002, our total outstanding debt, which represented approximately 63.9% of our total capitalization, was approximately $2.2 billion. These amounts are before the application of approximately $258.9 million in net proceeds before offering expenses from our January 2003 equity offering, For a description of our debt obligations, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Our liquidity and capital resources - Our debt obligations" under Item 7 of this annual report. For a discussion of subsequent events affecting our financial statements, please see our footnote titled "Subsequent Events" in the Notes to Consolidated Financial Statements under Item 8 of this annual report.

Debt service obligations, restrictive covenants and maturities resulting from this leverage may adversely affect our ability to finance future operations, pursue acquisitions and fund other capital needs, and may make our results of operations more susceptible to adverse economic or operating conditions. Our ability to repay, extend or refinance our existing debt obligations and to obtain future credit will depend primarily on our operating performance, which will be affected by general economic, financial, competitive, legislative, regulatory, business and other factors, many of which are beyond our control. Our ability to access the capital markets for future offerings may be limited by adverse market conditions resulting from, among other things, general economic conditions, contingencies and uncertainties that are difficult to predict and beyond our control.

If we are unable to access the capital markets for future offerings, we might be forced to seek extensions for some of our short-term maturities or to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit could be more onerous than those contained in our existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility.

A decrease in the difference between NGL product prices and natural gas prices results in lower margins on volumes processed, which would adversely affect our profitability.

The profitability of our operations depends upon the spread between NGL product prices and natural gas prices. NGL product prices and natural gas prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- the level of domestic production;
- the availability of imported oil and gas;
- actions taken by foreign oil and gas producing nations;
- the availability of transportation systems with adequate capacity;
- the availability of competitive fuels;
- fluctuating and seasonal demand for oil, gas and NGLs; and
- conservation and the extent of governmental regulation of production and the overall economic environment.

Our Processing segment is directly exposed to commodity price risks, as we take title to NGLs and are obligated under certain of our gas processing contracts to pay market value for the energy extracted from the natural gas stream. We are exposed to various risks, primarily that of commodity price fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. These pricing risks cannot be completely hedged or eliminated, and any attempt to hedge pricing risks may expose us to financial losses.

A reduction in demand for our products by the petrochemical, refining or heating industries could adversely affect our results of operations.

A reduction in demand for our 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 our results of operations. For example:

Ethane. If natural gas prices increase significantly in relation to ethane prices, it may be more profitable for natural gas processors 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 will cause the demand for propane to decline significantly and could cause a decline in the volumes of propane that we extract and transport.

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

MTBE. A number of states have either banned or currently are considering legislation to ban MTBE. In addition, Congress is contemplating a federal ban on MTBE, and several oil companies have taken an early initiative to phase out the production of MTBE. If MTBE is banned or if its use is significantly limited, the revenues and equity earnings we record related to its production may be materially reduced or eliminated. For additional information regarding MTBE, please read "Regulation and Environmental Matters--Impact of the Clean Air Act's oxygenated fuels programs on our BEF investment" on page 28 of this annual report.

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

Please read "The Company's Operations" beginning on page 6 of this annual report for a more detailed discussion of our operations.

A decline in the volume of NGLs delivered to our facilities could adversely affect our results of operations.

Our profitability is materially impacted by the volume of NGLs processed at our facilities. 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 the volume of NGLs delivered to our facilities for processing, thereby reducing revenue and operating income.

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

As a result of business failures, revelations of material misrepresentations and related financial restatements by several large, well-known companies in various industries over the last year, there have been significant disruptions and extreme volatility in the financial markets and credit markets. Because of the credit intensive nature of the energy industry and troubling disclosures by some large, diversified energy companies, the energy industry has been especially impacted by these developments, with the rating agencies downgrading a number of large energy-related companies. Accordingly, in this environment we are exposed to an increased level of credit and performance risk with respect to our customers. If we fail to adequately assess the creditworthiness of existing or future customers, unanticipated deterioration in their creditworthiness could have an adverse impact on us.

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

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing operations. We may encounter difficulties integrating these acquisitions with our existing businesses without a loss of employees or customers, a loss of revenues, an increase in operating or other costs or other difficulties. In addition, we may not be able to realize the operating efficiencies, competitive advantages, cost savings or other benefits expected from these acquisitions. Future acquisitions may require substantial capital or the incurrence of substantial indebtedness. As a result, our capitalization and results of operations may change significantly following an acquisition, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce distributions to our Unitholders and our ability to make payments on our debt securities.

The after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. If we were classified as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate rate. Some or all of the distributions made to Unitholders would be treated as dividend income, and no income, gains, losses or deductions would flow through to Unitholders. Treatment of us as a corporation would cause a material reduction in the anticipated cash flow and after-tax return to the Unitholders, likely causing a substantial reduction in the value of the common units. Moreover, treatment of us as a corporation would materially and adversely affect our ability to make payments on our debt securities.

In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced. The 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.

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

Since the September 11, 2001 terrorist attacks on the United States, the United States government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be the future target of terrorist organizations. Any terrorist attack on our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business. An escalation of political tensions in the Middle East and elsewhere, such as the recent commencement of United States military action in Iraq, could result in increased volatility in the world's energy markets and result in a material adverse effect on our business.

RECENT STRATEGIC ACQUISITIONS

The following is a brief summary of our strategic acquisitions since the end of 2001. Additional information regarding these acquisitions is contained in the rest of this annual report.

Acquisition of Mid-America and Seminole Pipeline Systems. On July 31, 2002, we completed the acquisition of an effective 98% interest in the Mid-America Pipeline System and an effective 78.4% interest in the Seminole Pipeline System from Williams for approximately $1.2 billion in cash. The Mid-America Pipeline System is a 7,226-mile NGL pipeline system connecting the Hobbs hub on the Texas-New Mexico border with supply regions in the Rocky Mountains and supply regions and markets in the Midwest. The Seminole Pipeline System is a 1,281-mile pipeline system that interconnects with the Mid-America pipeline system and transports mixed NGLs and NGL products from the Hobbs hub and Permian Basin to Mont Belvieu, Texas.

Acquisition of Propylene Fractionation Business ("Splitter III"). In February 2002, we completed the purchase of various propylene fractionation assets and certain inventories of propylene and propane from Diamond-Koch for approximately $239 million in cash. The primary asset acquired was a 66.7% interest in a polymer grade propylene fractionation facility located in Mont Belvieu, Texas having 41 MBPD of capacity.

Acquisition of Storage Business. In January 2002, we completed the purchase of various NGL and petrochemical storage assets from Diamond-Koch for approximately $130 million in cash. These storage facilities consist of 25 operational salt dome storage caverns located in Mont Belvieu, Texas with a practical capacity of 64 million barrels, local distribution pipelines and related equipment.

For additional information regarding these and other acquisitions completed during 2002, please see Note 4 titled "Business Acquisitions" in the Notes to Consolidated Financial Statements under Item 8 of this annual report.

THE COMPANY'S OPERATIONS

We have five reportable business segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. Pipelines consists of NGL, petrochemical and natural gas pipeline systems, storage, and import/export services. Fractionation primarily includes NGL and propylene fractionation and isomerization services. Processing includes our natural gas processing business and related NGL marketing activities. Octane Enhancement includes facilities that produce motor gasoline additives to enhance octane (currently producing MTBE). The Other segment consists of fee-based marketing services and various operational support activities.

For additional information regarding our business segments including revenues, gross operating margin and assets, see the Notes to Consolidated Financial Statements under Item 8 of this report.

PIPELINES

Our Pipelines segment owns or has interests in approximately 14,000 miles of NGL, petrochemical and natural gas transportation and distribution pipelines. This segment also includes our storage and import/export terminalling businesses.

NGL and petrochemical pipelines

Our NGL and petrochemical pipelines transport mixed NGLs and other hydrocarbons to our fractionation plants, distribute and collect NGL products and propylene 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 (which includes our NGL and petrochemical marketing activities). Typically, our NGL and petrochemical 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 and petrochemical 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 and petrochemical pipeline transportation and distribution networks:

NGL AND PETROCHEMICAL PIPELINES	LENGTH IN MILES	OUR OWNERSHIP INTEREST
Mid-America Pipeline System	7,226	98.0%
Dixie	1,301	19.9%
Seminole Pipeline System	1,281	78.4%
Louisiana Pipeline System	536	100.0%
Promix (1)	410	33.3%
Lou-Tex Propylene	291	100.0%
Lou-Tex NGL	206	100.0%
HSC	175	100.0%
Tri-States	169	33.3%
Chunchula	117	100.0%
Lake Charles/Bayport	87	50.0%
Belle Rose	48	41.7%
Wilprise	30	37.4%
Sabine Propylene	21	100.0%
La Porte (2)	17	50.0%
Total NGL and petrochemical pipelines	11,915	

(1) The Promix NGL pipelines are an integral component of the NGL fractionation activities of Promix, the assets and equity earnings of which are accounted for as part of our Fractionation segment.
(2) The La Porte pipeline is an integral component of the propylene fractionation activities of Splitter III, which is accounted for under our Fractionation segment. Our investment in and equity earnings from La Porte are reported under the Fractionation segment.

Mid-America Pipeline System. In July 2002, we acquired an effective 98% interest in the Mid-America Pipeline System (or "Mid-America") from Williams for approximately $934.8 million in cash. 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 Pipeline System crosses thirteen states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin. We also acquired fifteen unregulated propane terminals that are part of this system.

The Rocky Mountain system 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, through third-party pipeline connections, NGL supplies from Canada's Western Sedimentary basin. The Conway South system 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). Williams operated this pipeline under a transition services agreement through January 31, 2003, at which time we took over operation of this system.

Approximately 60% of the volumes transported on the Mid-America system are mixed NGLs sourced 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. For additional information regarding the consideration paid to acquire Mid-America, see our "Business Acquisitions" footnote in the Notes to Consolidated Financials under Item 8 of this annual report.

Dixie. The Dixie pipeline is a regulated 1,301-mile propane pipeline 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. We own a 19.9% interest in Dixie. An affiliate of ConocoPhillips operates the system.

Seminole Pipeline System. In July 2002, we acquired an effective 78.4% interest in the Seminole Pipeline System (or "Seminole") from Williams for approximately $248.2 million in cash. Seminole is a regulated 1,281-mile pipeline system 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 Pipeline System at the Hobbs hub. The primary source of throughput for Seminole is the volume originating from the Mid-America system. In general, the volumes transported by Seminole are ultimately used by petrochemical plants that manufacture various products in southeast Texas. Williams operated this pipeline under a transition services agreement through January 31, 2003, at which time we took over operation of this system. For additional information regarding the consideration paid to acquire Seminole, see our "Business Acquisitions" footnote in the Notes to Consolidated Financials under Item 8 of this annual report.

Louisiana Pipeline System. The Louisiana pipeline system is a 536-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 own 100% of 428 miles of this system with the remaining 108 miles belonging to joint ventures in which we have an ownership interest. We operate all but 43 miles of these pipelines.

Promix. The Promix pipeline system 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 system is an integral part of the Promix NGL fractionation facility, of which we own 33.3%.

Lou-Tex Propylene Pipeline System. The Lou-Tex propylene pipeline system consists of a 291-mile pipeline used to transport propylene from Sorrento, Louisiana to Mont Belvieu, Texas. Currently, this system 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 own and operate this system.

Lou-Tex NGL Pipeline System. 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 our Louisiana gas processing plants to our Mont Belvieu NGL fractionation facility. We own and operate this pipeline system.

HSC Pipeline System. 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 own and operate this pipeline system.

Tri-States, Belle Rose and Wilprise. We indirectly own interests in three pipelines that supply mixed NGLs to the BRF and Promix NGL fractionators. We own a 33.3% interest in Tri-States, which owns a l69-mile NGL pipeline that extends from Mobile Bay, Alabama to near Kenner, Louisiana. In addition, we own a 41.7% interest in and operate Belle Rose, which owns a 48-mile NGL pipeline that extends from the interconnect with Tri-States near Kenner, Louisiana to the Promix NGL fractionator. We own a 37.4% interest in Wilprise, which owns a 30-mile NGL pipeline that extends from the interconnect with Tri-States near Kenner, Louisiana to Sorrento, Louisiana. The mixed NGLs transported on these systems originate from gas processing facilities located along the Mississippi, Alabama and Louisiana Gulf Coast. BP operates the Tri-States system. Williams operated the Wilprise system through January 31, 2003, at which time we assumed the role of operator of this system.

Chunchula. The Chunchula pipeline system is a 117-mile NGL pipeline extending from the Alabama-Florida border to our storage and NGL fractionation facilities in Petal, Mississippi for further distribution. We own and operate this system.

Lake Charles/Bayport. Our 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 have a 50% ownership interest in and operate the 77-mile section of this system. We have varying ownership interests in the remaining 10 miles of this overall 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 own and operate this system.

La Porte. The La Porte pipeline system is a 17-mile pipeline used to distribute polymer grade propylene from Mont Belvieu, Texas to La Porte, Texas. This system is an integral part of our Splitter III operations. We own an aggregate 50% of the La Porte pipeline and operate the system.

NGL and petrochemical 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 and petrochemical pipelines are measured in terms of throughput (in MBPD, on a net basis).

	FOR YEAR ENDED DECEMBER 31,		
NGL AND PETROCHEMICAL PIPELINES	2002	2001	2000
Mid-America Pipeline System (1)	641	n/a	n/a
Dixie	21	26	14
Seminole Pipeline System (1)	202	n/a	n/a
Louisiana Pipeline System	179	138	115
Lou-Tex Propylene	25	27	23
Lou-Tex NGL	38	29	30
HSC	135	133	106
Tri-States, Wilprise and Belle Rose	44	36	42
Lake Charles/Bayport	11	6	5
Sabine Propylene (2)	11	n/a	n/a
Chunchula	5	5	6
Total net volume of NGL and petrochemical pipelines	1,312	400	341

(1) In July 2002, we acquired ownership interests in these systems from Williams. The throughput rates shown in the table above reflect operating data for the five months that we owned these systems during 2002. During 2001, average transportation volumes for the Mid-America and Seminole systems were 641 MBPD and 241 MBPD, respectively (both amounts on a gross basis). We own an effective 98% of the Mid-America system and 78.4% of the Seminole system.
(2) Our Sabine Propylene pipeline commenced operations during the first quarter of 2002.

Natural gas pipelines

Our natural gas pipeline systems provide for the gathering, transmission and storage of natural gas from both onshore and offshore 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. Acadian Gas is exposed to commodity price risk to the extent it takes title to natural gas volumes through certain of its contracts. Our Gulf of Mexico systems generally do not take title to the natural gas that they transport; rather the shipper retains title and the associated commodity price risk.

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

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 offshore natural gas pipelines exhibit little to no effects of seasonality; however, these systems may be affected by weather events such as hurricanes and tropical storms in the Gulf of Mexico.

Our onshore and offshore systems are affected by natural gas exploration and production activities. If these exploration and production activities decline as a result of a weakened domestic economy or due to 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 natural gas pipeline assets and ownership interests:

NATURAL GAS PIPELINES	LENGTH IN MILES	OUR OWNERSHIP INTEREST
Cypress	577	100.0%
Acadian	438	100.0%
Stingray	379	50.0%
VESCO (1)	260	13.1%
Manta Ray	235	25.7%
Nautilus	101	25.7%
Evangeline	27	49.5%
Nemo	24	33.9%
Total natural gas pipelines	2,041	

(1) The VESCO gas gathering pipelines are an integral part of the natural gas processing activities of VESCO. Accordingly, these pipelines are accounted for under our cost-method investment in VESCO, which is part of our Processing segment.

Acadian, Cypress and Evangeline. In April 2001, we acquired Shell's Acadian Gas natural gas pipeline business. This business is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. Its assets are comprised of the 438-mile Acadian and 577-mile Cypress natural gas pipelines and a leased natural gas storage facility with approximately 3 Bcf of natural gas storage capacity. Acadian Gas owns a 49.5% equity interest in Evangeline, which owns a 27-mile natural gas pipeline. We operate the Acadian Gas and Evangeline systems. Overall, the Acadian Gas and Evangeline systems are comprised of 1,042 miles of pipeline.

The Acadian Gas systems link 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, these systems have 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 systems originate from onshore Louisiana sources and offshore Gulf of Mexico production areas.

Stingray. In January 2001, we purchased a 50.0% indirect interest in the Stingray natural gas pipeline system and a related natural gas dehydration facility from El Paso. We own our interest in these assets through our 50.0% equity investment in Starfish, a joint venture with Shell. The Stingray system 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. Currently, natural gas transported by Stingray originates from the Garden Banks and East and West Cameron production areas of the Gulf of Mexico. Stingray's natural gas dehydration facility is connected to the onshore terminus of the system in south Louisiana. Shell is the operator of these systems and owns the remaining equity interest in Starfish.

Manta Ray, Nautilus and Nemo. In connection with our purchase of the Stingray interest, we also acquired from El Paso a 25.7% indirect interest in the Manta Ray and Nautilus natural gas pipeline systems located in the Gulf of Mexico offshore Louisiana. The Manta Ray system comprises approximately 235 miles of unregulated pipelines and related equipment and the Nautilus system comprises approximately 101 miles of regulated pipelines. Our ownership of the Manta Ray and Nautilus systems is through our unconsolidated affiliate, Neptune. We also purchased from El Paso a 33.9% indirect interest in the 24-mile Nemo natural gas pipeline, which became operational in August 2001. Like Stingray, Shell is the operator of the Manta Ray and Nemo systems. Shell is the administrative agent and Marathon the operator for Nautilus. Shell and Marathon are our co-owners in Neptune and Shell owns the remaining interest in Nemo.

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 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. BP, Shell and others have announced plans to build the Cleopatra pipeline that will transport natural gas from the Southern Green Canyon area of the Gulf of Mexico to Manta Ray. This pipeline is expected to be completed by the end of 2003. Presently, the only source of volumes for Nemo is Shell's Green Canyon development in the Brutus field.

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 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 natural gas pipelines are measured in terms of throughput (in BBtus per day, on a net basis).

NATURAL GAS PIPELINES	FOR YEAR ENDED DECEMBER 31, 2002	2001
Acadian Gas and Evangeline	704	783
Stingray	267	300
Manta Ray, Nautilus and Nemo	236	266
Total net volume of natural gas pipelines	1,207	1,349

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 our practical (or useable) storage capacity and net storage capacity by state (net storage capacity is based on our level of ownership in the assets):

NGL AND PETROCHEMICAL STORAGE ASSETS	PRACTICAL CAPACITY, MMBBLS	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, of which 64 MMBbls of this capacity was acquired from Diamond-Koch in January 2002 for approximately $130 million. 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 purchase of the Mid-America and Seminole pipeline systems in July 2002, we acquired 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 processing 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 intersegment 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.

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 rates 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 predominately higher during the winter months due to increased propane exports. Prior to March 2003, we owned 50.0% of this export facility through our equity investment in EPIK. On March 1, 2003, we acquired the remaining 50.0% ownership interests in this facility for $19 million plus certain post-closing working capital adjustments.

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.

OTC. In February 2002, we acquired a 50.0% interest in OTC, which owns an above ground polymer grade propylene storage and export facility located in Seabrook, Texas. The facility is operated by Baytank with administrative services provided by JLM Industries. We acquired our interest in OTC in connection with our purchase of the Splitter III propylene fractionation facility from Diamond-Koch. This facility can load vessels of polymer grade propylene at rates up to 5,000 barrels per hour. OTC's primary competitor is an export operation owned by ChevronPhillips located on the Houston Ship Channel. OTC's operations are an integral part of our Splitter III propylene fractionation business, of which the assets and earnings (including those of OTC) are accounted for as part of our Fractionation segment.

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,		
	2002	2001	2000
NGL import facility	22	45	9
NGL export facility	19	8	17
OTC (1)	4	n/a	n/a
Total net imports and exports	45	53	26

(1) The OTC propylene export facility is an integral part of our Splitter III propylene fractionation operations. Accordingly, this facility is accounted for under Splitter III, which is part of our Fractionation segment.

FRACTIONATION

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 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 mixed NGL recovery levels of gas processing plants 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 toll fee arrangements. This fee (typically in cents per gallon) is subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs. At our Norco and Toca-Western facilities, we perform fractionation services for certain customers by retaining a percentage of the NGLs we fractionate for them as payment (an "in-kind" fee). The results of operations of our NGL fractionation business are dependent upon the volume of mixed NGLs processed and either the level of toll processing fees charged (in toll fee-based operations) or the value of NGLs received (applicable to in-kind fee arrangements). We are exposed to fluctuations in NGL prices to the extent we receive in-kind fees for our services. Our tolling 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.

Our NGL fractionation operations include eight NGL fractionators with a combined gross processing capacity of 572 MBPD and a net processing capacity to us of 331 MBPD. The following table summarizes our NGL fractionation facilities:

NGL FRACTIONATION FACILITY	LOCATION	GROSS CAPACITY, MBPD	OUR OWNERSHIP INTEREST	NET CAPACITY, MBPD
Mont Belvieu	Texas	210	75.00%	158
Promix	Louisiana	145	33.33%	48
Norco	Louisiana	70	100.00%	70
BRF	Louisiana	60	32.24%	19
Venice	Louisiana	36	13.10%	5
Tebone	Louisiana	30	33.70%	10
Toca-Western	Louisiana	14	100.00%	14
Petal	Mississippi	7	100.00%	7
	Total	572		331

During 2002, our NGL fractionation facilities processed mixed NGLs at an average rate of 235 MBPD or 75% of capacity, both amounts on a net basis. The following table shows net processing volumes and capacity (in MBPD) and the corresponding overall utilization rates of our NGL fractionation facilities for the last three years:

NGL FRACTIONATION FACILITY	FOR YEAR ENDED DECEMBER 31, 2002	2001	2000
Mont Belvieu	127	110	106
Promix	30	30	34
Norco	41	41	47
BRF	17	14	15
Other	20	9	11
Total net volume	235	204	213
Net capacity (1)	313	290	290
Utilization rate	75%	70%	73%

(1) Net capacity amounts have been adjusted for the timing of acquisitions

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 the key hub of the domestic 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 processes mixed NGLs from several major NGL supply basins in North America including the Mid-Continent, Permian Basin, San Juan Basin, Rocky Mountain Overthrust and the U.S. Gulf Coast. Our Mont Belvieu NGL fractionation facility is supported by long-term fractionation agreements with Burlington Resources and Duke (which accounted for 73 MBPD of net processing volume in 2002), each of which is a significant producer of NGLs and a co-owner of the facility. In June 2002, we purchased an additional 12.5% ownership interest in these assets from ChevronTexaco for approximately $8.1 million. As a result, we own an effective 75% interest in this facility.

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.

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 has a gross processing capacity of 70 MBPD. During 2002, long-term in-kind fee arrangements exclusive to this facility accounted for approximately 32 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.

Toca-Western. We own and operate an integrated NGL fractionation and natural gas processing facility located in St. Bernard Parish, Louisiana that we acquired in 2002. The NGL fractionator contained within this complex has a gross and net processing capacity of 14 MBPD.

Tebone. We own a 33.7% 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.

Petal. We own and operate an NGL fractionation facility at Petal, Mississippi that has an average production capacity of 7 MBPD. The Petal facility is connected to our Chunchula pipeline system and serves NGL producers in Mississippi, Alabama and Florida.

Venice. 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 facility is part of the integrated natural gas processing complex owned by VESCO.

Isomerization

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 clean fuel additives such as MTBE 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 alkylation, propylene oxide and in the production of MTBE.

We use the isomerization facilities to convert normal butane into isobutane, including high purity grade. Customers utilizing the services provided by these facilities include third parties and our Processing segment's NGL marketing activities. Our larger third-party toll processing customers, such as Lyondell and Huntsman, 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 various toll processing agreements to meet BEF's feedstock requirements. The isomerization facilities are also used by our Processing 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 2002, 18 MBPD of isobutane production was attributable to our NGL marketing activities, 16 MBPD to BEF-related contracts, with the balance related to various toll processing arrangements.

Our isomerization business includes three butamer reactor units and eight associated DIBs located in Mont Belvieu, Texas, which comprise the largest commercial isomerization complex in the United States. These facilities have an average combined production capacity of 116 MBPD of isobutane. We own the isomerization facilities with the exception of one of the butamer reactor units, which we control through a long-term lease. We operate the facilities. The following table shows isobutane production and capacity (both in MBPD) and overall utilization for the last three years:

	FOR YEAR ENDED DECEMBER 31,		
MONT BELVIEU ISOMERIZATION FACILITY	2002	2001	2000
Production	84	80	74
Net capacity	116	116	116
Utilization rate	72%	69%	64%

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

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. Likewise, 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.

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. Our largest toll processing customers in 2002 were Huntsman and Equistar. As part of our petrochemical marketing activities, 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 2002, 11 MBPD of our net polymer grade propylene production was associated with toll processing operations with the balance attributable to petrochemical marketing activities. Overall, the propylene fractionation business exhibits little seasonality.

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 system 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 as a result of our investment in OTC.

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. Our propylene fractionation business consists of three polymer grade propylene facilities and one chemical grade propylene plant. The following table summarizes our propylene fractionation business assets and ownership:

PROPYLENE FRACTIONATION FACILITY	LOCATION	GROSS CAPACITY, MBPD	EFFECTIVE OWNERSHIP INTEREST	NET CAPACITY, MBPD
Splitter I	Texas	17	100.0%	17
Splitter II	Texas	14	100.0%	14
Splitter III	Texas	41	66.7%	27
BRPC	Louisiana	23	30.0%	7
	Total	95		65

During 2002, our propylene fractionation facilities produced at an average rate of 56 MBPD or 89% of capacity, both amounts on a net basis. The table below shows our net production volumes and capacity (both in MBPD) based on our ownership interest and the corresponding overall utilization rates of our facilities for the last three years:

PROPYLENE FRACTIONATION FACILITY	FOR YEAR ENDED DECEMBER 31, 2002	2001	2000
Splitter I & II	27	27	29
Splitter III	25	n/a	n/a
BRPC	4	4	4
Total net volume	56	31	33
Net capacity (1)	63	38	35
Utilization rate	89%	82%	94%

(1) Net capacity amounts have been adjusted for the timing of acquisitions

Splitter I, II and III. 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. We own a 54.6% interest in Splitter I, all of Splitter II and a 66.7% interest in Splitter III. We lease the remaining 45.4% interest in Splitter I from an affiliate of Shell. We acquired the Splitter III facility and related assets from Diamond-Koch in February 2002 for $239 million in cash. Approximately 80% of the feedstock requirements of these facilities are under long-term supply contracts, with the remaining 20% 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.

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.

PROCESSING

The Processing segment consists of our natural gas processing business and related NGL marketing activities. At the core of our natural gas processing business are thirteen processing plants located on the Louisiana and Mississippi Gulf Coast with a gross natural gas processing capacity of 11.77 Bcf/d (3.37 Bcf/d on a net basis). The following table lists our gas processing plants, gross and net processing capacities and our current ownership interest in each facility:

NATURAL GAS PROCESSING FACILITY	LOCATION	GROSS GAS PROCESSING CAPACITY (BCF/D)	OUR OWNERSHIP INTEREST	NET GAS PROCESSING CAPACITY (BCF/D)
Toca	Louisiana	1.10	59.9%	0.66
Yscloskey	Louisiana	1.85	32.1%	0.59
Calumet	Louisiana	1.60	31.3%	0.50
Pascagoula	Mississippi	1.00	40.0%	0.40
North Terrebonne	Louisiana	1.30	28.8%	0.37
Neptune	Louisiana	0.30	66.0%	0.20
Venice	Louisiana	1.30	13.1%	0.17
Toca-Western	Louisiana	0.16	100.0%	0.16
Sea Robin	Louisiana	0.95	15.5%	0.15
Burns Point	Louisiana	0.16	50.0%	0.08
Blue Water	Louisiana	0.95	7.4%	0.07
Iowa	Louisiana	0.50	2.0%	0.01
Patterson II	Louisiana	0.60	2.0%	0.01
	Total	11.77		3.37

The majority of the operating margin earned by our natural gas processing plants is based on the relative economic value of the mixed NGLs extracted by the gas plants as compared to the costs of extracting the mixed NGLs (principally that of natural gas as a feedstock and as a fuel, plus plant operating expenses). Natural gas processing arrangements where the processor takes title to the NGLs extracted from the natural gas stream and reimburses producers for the market value of the energy extracted based upon the Btus consumed from the natural gas stream in the form of fuel and mixed NGLs are defined as "keepwhole" contracts. The processor derives a profit margin from these contracts to the extent the market value of the NGLs extracted exceeds the costs of extraction.

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 when the market value of the NGLs exceeds the cost (principally that of natural gas as a feedstock and as a fuel) of extracting the mixed NGLs. 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.

The natural gas processing capacities of the plants are based on practical limitations. Our utilization of these gas plants depends upon general economic and operating conditions and is generally measured in terms of equity NGL production. Equity NGL production is defined as the volume of NGLs extracted by the gas plants to which we take title under the terms of processing agreements or as a result of our plant ownership interests. Equity NGL production can be adversely affected by high natural gas costs and/or low purity NGL product prices. Our equity NGL production averaged 73 MBPD during 2002, 63 MBPD during 2001 and 72 MBPD during 2000.

The most significant contract affecting our natural gas processing business is the 20-year Shell processing agreement, which grants us the right to process Shell's current and future production from the Gulf of Mexico within the state and federal waters off Texas, Louisiana, Mississippi, Alabama and Florida on a keepwhole basis. This includes natural gas production from deepwater developments. This is a life of lease dedication, which may extend the agreement well beyond 20 years. Shell is one of the largest oil and gas producers and holds one of the largest lease positions in the deepwater Gulf of Mexico. Generally, this contract has the following rights and obligations:

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

- the exclusive right, but not the obligation, 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 plants from Shell's natural gas production from such leases; with

- the obligation to re-deliver to Shell the natural gas stream after the mixed NGL stream is extracted.

We believe that natural gas and its associated NGL production from the Gulf of Mexico will significantly increase in the coming years as a result of advances in seismic and deepwater development technologies and continued capital spending for exploration and production by major oil companies.

As noted previously, 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 Fractionation 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 flat throughout the year. Our inventory cycle begins in late-February to mid-March (the seasonal low point); builds through September; remains flat until early December; before being drawn down through winter until the seasonal low is reached again.

Since we take title to NGLs and are obligated under certain of our gas processing contracts to pay market value for or replace the energy 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., to not being processed and made marketable). 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 natural gas cost reductions and other economic incentives to gas processors). During periods of extreme commodity price fluctuations, we reserve the right 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.

Our NGL marketing activities utilize a fleet of approximately 660 railcars, the majority of which are under short and long-term leases. The 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 and Petal, Mississippi. These facilities service both our rail shipments and those of our customers.

This segment includes our 13.1% investment in VESCO. VESCO 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 acquired four NGL terminals (primarily in propane service) from CornerStone in November 2002. These terminals are located in Bakersfield and Rocklin, California; Reno, Nevada and Albertville, Alabama and have an aggregate storage capacity of 0.1 million barrels of NGLs.

OCTANE ENHANCEMENT

The Octane Enhancement segment consists of our 33.3% interest in BEF, which owns a facility that produces motor gasoline additives to enhance octane. Our partners in BEF are affiliates of Sunoco and Devon Energy. The BEF facility currently produces MTBE and is located within our Mont Belvieu complex. The gross production capacity of the MTBE facility is approximately 16.5 MBPD with a net production capacity of 5.5 MBPD. For the years 2002, 2001 and 2000, BEF operated at near capacity levels. EPCO operates the facility.

The production of MTBE is driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990 and other legislation and as an additive to increase octane in motor gasoline. Any changes to the oxygenated fuel programs that enable localities to elect to not participate in these programs, lessen the requirements for oxygenates or favor the use of non-isobutane based oxygenated fuels would reduce the demand for MTBE and could have a negative impact on our operations. Although oxygenated fuel requirements can be satisfied by using other products such as ethanol, MTBE is the most widely used due to its ready availability and history of acceptance by refiners.

MTBE demand is primarily linked to motor gasoline requirements in certain urban areas of the United States designated as carbon monoxide and ozone non-attainment areas by the Clean Air Act Amendments of 1990 and the California oxygenated motor gasoline program. 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. BEF has a ten-year off-take agreement with Sunoco under which Sunoco is obligated to purchase all of BEF's MTBE production through September 2004. Beginning in June 2000 and for the remaining term of this agreement, Sunoco is required to purchase all of the plant's MTBE production at spot-market related prices. Sunoco uses this MTBE primarily to satisfy the gasoline blending requirements of its markets located in the eastern United States.

Historically, the spot price for MTBE has been at a modest premium to gasoline blend values. BEF is exposed to commodity price risk due to the market-related pricing provisions of the Sunoco off-take agreement. In general, MTBE prices are stronger during the April to September period of each year, which corresponds with the summer driving season. Future MTBE demand is highly dependent upon environmental regulation, federal legislation and the actions of individual states (see "Recent regulatory and legal developments" below within this section).

Each owner of BEF is responsible for supplying one-third of the facility's isobutane feedstock requirements through June 2004. We, along with the other two co-owners, use high purity isobutane produced at our Mont Belvieu isomerization facilities to meet this obligation. The methanol feedstock used by BEF is purchased from third parties under long-term contracts and transported to Mont Belvieu using our HSC pipeline system. BEF's methanol feedstock originates from a number of domestic and foreign producers, including those located in Venezuela, Chile, New Zealand and the Caribbean. Lastly, BEF's MTBE production is transported to a location on the Houston Ship Channel for delivery to Sunoco using our HSC pipeline system.

The MTBE market has a number of producers, including a number of refiners who produce MTBE for internal consumption in the manufacture of reformulated motor gasoline. In general, MTBE producers compete in terms of price and production (in terms of economies of scale and quality of product). While the Sunoco contract is in effect, BEF is not directly exposed to its competition, although it is affected by market pricing through the Sunoco off-take agreement. The large size of the BEF facility, combined with the technological advances incorporated into its construction and maintenance, make it one of the most efficient domestic MTBE plants in operation.

Recent regulatory and legal developments. 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. Although these detections have been limited and the great majority have been well below levels of public health concern, there have been calls for the phase-out of MTBE in motor gasoline in various federal and state governmental agencies and advisory bodies. BEF has not been named in any MTBE legal action to date. For additional information regarding the impact of environmental regulation on BEF, see "Impact of the Clean Air Act's oxygenated fuels programs on our BEF investment" on page 28. For a brief discussion of recent significant legal challenges involving MTBE, see "Uncertainties regarding our investment in facilities that produce MTBE" under Item 7 of this report.

Alternative uses of the BEF facility. In light of these developments, we and the other two owners of BEF are actively compiling a contingency plan for the BEF facility should MTBE be banned. We are currently evaluating a possible conversion of the facility from MTBE production to alkylate production. In addition to MTBE's value in reducing air pollution, it is a significant source of octane in the U.S. motor gasoline pool. Octane is a critical component of motor gasoline. Therefore, we believe that if MTBE usage is banned or significantly curtailed, the motor gasoline industry would need a substitute additive to maintain octane levels in gasoline and that alkylate would be an economic and effective substitute. We are currently conducting a detailed engineering study that is expected to be completed by the end of 2003, at which time we expect a more definitive conversion cost estimate will be available. The cost to convert the facility will depend on the type of alkylate process chosen and the level of production desired by the partnership.

OTHER

This operating segment is comprised of fee-based marketing services and unallocated costs of engineering services, construction equipment rentals and computer network services that support our operations and business activities. For a small number of clients, we perform NGL marketing services for which we charge a commission. The clients we serve are primarily located in the states of Washington, California and Illinois. Commissions are generally based on either a percentage of the final sales price negotiated on behalf of the client or on a fixed fee per gallon basis. Our fee-based marketing services handle approximately 29 MBPD of various NGL products with the period of highest activity occurring during the summer months. The principal elements of competition in this business are price and quality of service.

EMPLOYEES

We do not have any employees. EPCO employs most of the persons necessary for the operation of our business. At December 31, 2002, EPCO had approximately 1,000 employees involved in the management and operations of our business, none of whom were members of a union. We fully reimburse EPCO for the costs of approximately 900 of these employees, with the remainder of this group covered under the fixed-fee payments we make under the EPCO Agreement (for a detailed discussion of the EPCO Agreement, please read Item 13 of this annual report). In addition to EPCO employees, we have engaged approximately 150 contract maintenance and other personnel who support our operations.

On February 1, 2003, we assumed the operations of the Mid-America and Seminole pipelines from Williams. As a result, EPCO hired from Williams approximately 270 employees involved in the operations and administration of these systems. We will fully reimburse EPCO for the costs associated with these new employees.

MAJOR CUSTOMERS

Our revenues are derived from a wide customer base. Our largest customer, Shell and its affiliates, accounted for 7.8%, 10.5% and 9.5% of consolidated revenues in 2002, 2001 and 2000, respectively.

Approximately 88% of our revenue from Shell and its affiliates during 2002 was attributable to the sale of NGL products which are recorded in our Processing segment.

REGULATION AND ENVIRONMENTAL MATTERS

Regulation of our interstate common carrier liquids pipelines

Our Mid-America, Seminole, Chunchula, Lou-Tex Propylene, Lou-Tex NGL and Lake Charles/Bayport 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 or the nature of the service underlying the rate had substantially changed or that the rate was unduly discriminatory or preferential. These grandfathering provisions and the circumstances under which they may be challenged have received only limited attention from the FERC, causing a degree of uncertainty as to their application and scope. The Mid-America, Seminole, Chunchula and Lake Charles/Bayport 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 a new indexing rate methodology for petroleum pipelines. Under the new 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 novelty and 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 another FERC proceeding involving SFPP, L.P. ("SFPP"), another unrelated pipeline limited partnership, 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. 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. 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 rates are set using the indexing method and/or have been grandfathered. 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 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 revised FERC pricing policy by waiving price ceilings for short-term released capacity for a two-year period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. The U.S. Court of Appeals for the District of Columbia Circuit recently 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. Commencing in April 2000, FERC issued Order Nos. 639 and 639-A (collectively, "Order No. 639"), which required "gas service providers" operating on the outer continental shelf to make public their rates, terms and conditions of service. The purpose of Order No. 639 was to provide regulators and other interested parties with sufficient information to detect and remedy discriminatory conduct by such service providers. In a recent decision, the U.S. District Court for the District of Columbia permanently enjoined the FERC from enforcing Order No. 639, on the basis that the FERC did not possess the requisite rulemaking authority under the OCSLA for issuing Order No. 639. FERC's appeal of the court's decision is pending in the U.S. Court of Appeals for the District of Columbia Circuit. We cannot predict the outcome of this appeal, nor can we predict what further action FERC will take with respect to this matter.

On September 27, 2001, FERC issued a Notice of Proposed Rulemaking in Docket No. RM01-10. The proposed rules would expand FERC's current standards of conduct to include a regulated transmission provider and all of its energy affiliates. It is not known whether FERC will issue a final rule in this docket and, if it does, whether we could, as a result, incur increased costs and difficulty in our operations.

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 Wilprise pipelines 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.

Potential impact of regulation on our electrical cogeneration assets

We produce electricity for internal consumption at our Mont Belvieu complex. If this electricity were sold to third parties, our Mont Belvieu cogeneration facilities could be certified as qualifying facilities under the Public Utility Regulatory Policy Act of 1978 ("PURPA"). Subject to compliance with certain conditions under PURPA, this certification would exempt us from most of the regulations applicable to electric utilities under the Federal Power Act and the Public Utility Holding Company Act, as well as from most state laws and regulations concerning the rates, finances, or organization of electric utilities. However, since such electric power is consumed entirely at our facilities, the cogeneration activities are not subject to public utility regulation under federal or Texas law.

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 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 emission sources of so-called 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 2003 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 33.33% 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. On March 25, 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. California's deadline for the complete phase-out of MTBE is December 31, 2003. At least twelve other states are following California's lead and either have banned or currently are considering legislation to ban MTBE. Congress is also contemplating a federal ban on MTBE. On April 25, 2002, the Senate approved an energy bill that in part would have banned the use of MTBE within four years of enactment 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 in the new Congress that convened in January 2003, 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 banned or if its use is significantly limited, the revenue

BEF derives from MTBE production would be reduced or eliminated, which in turn would affect the equity earnings we record from BEF in our Octane Enhancement 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 a ban on MTBE production, the revenues we record in our Fractionation segment for isomerization services and in our Processing segment for sales of isobutane could be unfavorably impacted.

Legislation introduced in the U.S. Senate in 2001 and 2002, as part of an 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. This legislation, as well as legislation to allow California to ban MTBE, was defeated. The outlook for the new Congress that convened in January 2003 is uncertain, and no assurance can be given as to whether or not the federal government or individual states will ultimately adopt legislation banning or promoting the use of MTBE as part of their clean air programs.

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 under the Texas Natural Resources Code 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 oil 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. On November 15, 2002, Congress passed the Pipeline Safety Improvement Act, which contains requirements for the development of integrity management programs or gas pipelines located in certain "high consequence areas." On January 28, 2003, the OPS issued a proposed rulemaking that would require gas pipeline operators to develop integrity management programs for gas transmission pipelines that, in the event of a failure, could impact high consequence areas. The proposed rulemaking has not been finalized and is still subject to public comment. Similar integrity management program requirements have already been implemented for oil pipelines located in or near high consequence areas. We believe that our pipeline operations are in substantial compliance with applicable regulations. Furthermore, we believe the implementation of currently proposed pipeline safety regulations would not have a significant impact on our results of operations or financial position.

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 combined annual reports for both registrants on Form 10-K; combined quarterly reports for both registrants on Form 10-Q; combined and separate 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 of our registrants. 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 the SEC. You may also contact our investor relations department at 713-880-6500 for paper copies of these reports free of charge.

ITEM 3. LEGAL PROCEEDINGS.

On occasion, we are named as a defendant in litigation relating to our normal business operations. Although we are insured against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activity. We are aware of no significant litigation, pending or threatened, that may have a significant adverse effect on our financial position or results of operations.

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

There were no matters submitted to a vote of our Unitholders during the fourth quarter of 2002.

PART II

ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY AND RELATED UNITHOLDER MATTERS.

The following table sets forth, for the periods indicated, the high and low prices per Common Unit (as reported under the symbol "EPD" on the NYSE) and the amount of quarterly cash distributions paid per Common and Subordinated Unit.

	PRICE RANGES (1)		CASH DISTRIBUTION HISTORY			
	HIGH	LOW	PER COMMON UNIT (1)	PER SUBORDINATED UNIT (1)	RECORD DATE	PAYMENT DATE
2001						
1st Quarter	$18.40	$13.25	$0.2750	$0.2750	Apr. 30, 2001	May 10, 2001
2nd Quarter	$21.88	$16.60	$0.2938	$0.2938	Jul. 31, 2001	Aug. 10, 2001
3rd Quarter	$24.18	$19.75	$0.3125	$0.3125	Oct. 31, 2001	Nov. 9, 2001
4th Quarter	$26.30	$21.80	$0.3125	$0.3125	Jan. 31, 2002	Feb. 11, 2002
2002						
1st Quarter	$25.79	$24.94	$0.3350	$0.3350	Apr. 30, 2002	May 10, 2002
2nd Quarter	$24.50	$16.25	$0.3350	$0.3350	Jul. 31, 2002	Aug. 12, 2002
3rd Quarter	$22.23	$15.00	$0.3450	$0.3450	Oct. 31, 2002	Nov. 12, 2002
4th Quarter	$19.80	$16.41	$0.3450	$0.3450	Jan. 31, 2003	Feb. 12, 2003

(1) As appropriate, the historical pricing and other data presented within this table have been adjusted for the two-for-one Unit split that occurred in May 2002.

The quarterly cash distribution amounts shown in the table correspond to the cash flows for the quarters indicated. The actual cash distributions (i.e., payments to our limited partners) occur within 45 days after the end of such quarter. The increased quarterly cash distribution rates are attributable to the growth in cash flow that we have achieved through the completion of new projects, improved operating results and accretive acquisitions. Although the payment of such quarterly cash distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

As of February 28, 2003, there were approximately 24,667 beneficial owners of our Common Units, which includes an estimated 223 Unitholders of record.

ITEM 6. SELECTED FINANCIAL DATA.

The following table sets forth for the periods and at the dates indicated, selected historical financial data for the Company and Operating Partnership. The selected historical financial data have been derived from the audited financial statements of each registrant for the periods indicated. The selected historical income statement data for each of the three years ended December 31, 2002, 2001 and 2000 and the selected balance sheet data as of December 31, 2002 and 2001 should be read in conjunction with the audited financial statements for such periods included under Item 8 of this report for both entities. In addition, combined information regarding results of operations and capital resources and liquidity can be found under Item 7 of this report, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

The dollar amounts in each table, except per Unit data for the Company, are in thousands. Additionally, certain reclassifications have been made to prior years financial statements to conform to the current year presentation.

ENTERPRISE PRODUCTS PARTNERS L.P. AND SUBSIDIARIES, CONSOLIDATED

	2002	2001	2000	1999	1998
INCOME STATEMENT DATA:					
Revenues	$ 3,584,783	$ 3,154,369	$ 3,049,020	$ 1,332,979	$ 738,902
Operating income	$ 194,585	$ 287,688	$ 243,734	$ 132,351	$ 50,473
Extraordinary charge related to the extinguishment of debt					$ (27,176)
Net income	$ 95,500	$ 242,178	$ 220,506	$ 120,295	$ 10,077
Basic net income per Unit (1)	$ 0.55	$ 1.70	$ 1.62	$ 0.90	$ 0.09
Diluted net income per Unit (2)	$ 0.48	$ 1.39	$ 1.32	$ 0.82	$ 0.09
BALANCE SHEET DATA (AT PERIOD END):					
Total assets	$ 4,230,272	$ 2,424,692	$ 1,951,368	$ 1,494,952	$ 741,037
Long-term and current maturities of debt	$ 2,246,463	$ 855,278	$ 403,847	$ 295,000	$ 90,000
Partners' equity	$ 1,200,904	$ 1,146,922	$ 935,959	$ 789,465	$ 562,536
OTHER FINANCIAL DATA:					
Cash distributions declared per Common Unit (3)	$ 1.3600	$ 1.1940	$ 1.0500	$ 0.9250	$ 0.3850
Commodity hedging income (losses)	$ (51,344)	$ 101,290	$ 26,743	$ (5,208)	N/A

(1) Net income allocable to our Limited Partners divided by the weighted-average number of Common and Subordinated Units outstanding during the period.
(2) Net income allocable to our Limited Partners divided by the weighted-average number of Common, Subordinated and Special Units outstanding during the period.
(3) Cash distributions began after our initial public offering of Common Units on July 27, 1998. See Item 5 of this annual report for additional information regarding cash distributions.

OPERATING PARTNERSHIP AND SUBSIDIARIES, CONSOLIDATED

	2002	2001	2000	1999	1998
INCOME STATEMENT DATA:					
Revenues	$ 3,584,783	$ 3,154,369	$ 3,049,020	$ 1,332,979	$ 738,902
Operating income	$ 194,811	$ 287,172	$ 243,734	$ 132,351	$ 50,473
Extraordinary charge related to the extinguishment of debt					$ (27,176)
Net income	$ 96,952	$ 244,178	$ 223,068	$ 121,730	$ 10,057
BALANCE SHEET DATA (AT PERIOD END):					
Total assets	$ 4,231,561	$ 2,424,722	$ 1,948,610	$ 1,492,712	$ 741,037
Long-term and current maturities of debt	$ 2,246,463	$ 855,278	$ 403,847	$ 295,000	$ 90,000
Partners' equity	$ 1,211,736	$ 1,153,618	$ 942,671	$ 794,626	$ 567,273
OTHER FINANCIAL DATA:					
Commodity hedging income (losses)	$ (51,344)	$ 101,290	$ 26,743	$ (5,208)	N/A

Since we are the parent of the Operating Partnership, we consolidate its operations and financial results with our own. The Operating Partnership owns substantially all of our consolidated assets and conducts substantially all of our business and operations. As a result, there is very little difference between our financial information and that of the Operating Partnership. In general, our consolidated results of operations and financial position have been materially affected by acquisitions since 1999. Our more significant acquisitions during this period were:

- William's Mid-America and Seminole pipelines in July 2002 for $1.2 billion;
- Diamond-Koch's propylene fractionation business in February 2002 for $239 million ;
- Diamond-Koch's NGL and petrochemical storage business in January 2002 for $129.6 million;
- Shell's Acadian Gas pipeline business in April 2001 for $243.7 million;
- El Paso's equity interests in four Gulf of Mexico natural gas pipelines in January 2001 for $113 million; and
- Shell's TNGL natural gas processing and related businesses in August 1999 for $528.8 million.

With the exception of our purchase of TNGL and Diamond-Koch's storage business, our acquisitions have been financed primarily through borrowings. In October 2002 and January 2003, we completed two public Common Unit offerings from which we received $442.1 million, which we subsequently used to repay a portion of the debt we incurred in the Mid-America and Seminole acquisitions. We used cash on hand to acquire Diamond-Koch's storage business. Our acquisition of TNGL was accomplished through cash payments and the issuance of partnership equity to Shell.

Operating income and net income include the results of our commodity hedging activities. We entered into these activities as a result of acquiring TNGL's natural gas processing and related businesses from Shell in August 1999. To manage the risks associated with our Processing 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. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes. For additional information regarding our use of financial instruments, please read Item 7A of this annual report. In addition, please see our footnote titled "Financial Instruments" in the Notes to Consolidated Financial Statements under Item 8 of this annual report.

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 98.9899% 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 1.0% interest in us and a 1.0101% interest in our Operating Partnership. 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 the audited consolidated financial statements and notes thereto of the Company and Operating Partnership included under Item 8 of this report on Form 10-K. 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 Item 7A "Quantitative and Qualitative Disclosures about Market Risk" beginning on page 55 of this report. Additionally, please see Part III, Item 13 for a discussion of related-party matters, including our relationship with Shell.

OUR RESULTS OF OPERATION

We have five reportable operating segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. Pipelines consists of NGL, petrochemical and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization and propylene fractionation. Processing includes our natural gas processing business and related NGL marketing activities. Octane Enhancement represents our interest in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other operating segment consists of fee-based marketing services and various operational support activities.

Our management evaluates segment performance based on our measurement of segment gross operating margin. Gross operating margin for each segment represents operating income before depreciation and amortization, lease expense obligations retained by EPCO, gains and losses on the sale of assets and selling, general and administrative expenses. Segment gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges.

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 a supplier of raw materials or a consumer of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand alone basis. Many of these businesses perform supporting or complementary roles to our other business operations. For additional information regarding our business segments, see the Notes to our Consolidated Financial Statements under Item 8 of this annual report.

Under the terms of an agreement we executed with EPCO at our formation in 1998 (the "EPCO Agreement", see Item 13), EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for one dollar per year (the "retained leases"). EPCO holds these items pursuant to operating leases for which it has agreed to retain the corresponding lease payment obligation. Operating costs and expenses (as shown in the Statements of Consolidated Operations and Comprehensive Income) treat the lease payments being made by EPCO as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded as a general contribution to the partnership. EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases. In addition, EPCO has assigned to us the purchase options associated with these leases. These purchase options are based on the estimated fair market values of the equipment at the end of their respective lease terms. For additional information regarding these retained leases, see Item 13 of this annual report and our "Capital Spending" disclosure on page 68.

The following table shows our measurement of total gross operating margin for the periods indicated (dollars in thousands):

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Revenues (1)	$ 3,584,783	$ 3,154,369	$ 3,049,020
Operating costs and expenses (1)	(3,382,561)	(2,861,743)	(2,801,060)
Equity in income of unconsolidated affiliates (2)	35,253	25,358	24,119
Subtotal	237,475	317,984	272,079
Add: Depreciation and amortization in operating costs and expenses (3)	86,029	48,775	35,621
Retained lease expense, net in operating costs and expenses (4)	9,124	10,414	10,645
(Gain) loss on sale of assets in operating costs and expenses (3)	(1)	(390)	2,270
Total segment gross operating margin	$ 332,627	$ 376,783	$ 320,615

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(1) Amounts are comprised of both third party and related party totals from the Statements of Consolidated Operations and Comprehensive Income
(2) Amount taken from Statements of Consolidated Operations and Comprehensive Income
(3) Amount taken from Statements of Consolidated Cash Flows
(4) Amount represents leases paid by EPCO and the related contribution by the minority interest as reflected on the Statements of Consolidated Cash Flows

Our measurement of gross operating margin amounts by segment along with a reconciliation to consolidated operating income were as follows for the periods indicated (dollars in thousands):

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Gross operating margin by segment:			
Pipelines	$ 214,932	$ 96,569	$ 56,099
Fractionation	129,000	118,610	129,376
Processing	(17,633)	154,989	122,240
Octane enhancement	8,569	5,671	10,407
Other	(2,241)	944	2,493
Total segment gross operating margin	332,627	376,783	320,615
Depreciation and amortization	(86,029)	(48,775)	(35,621)
Retained lease expense, net	(9,124)	(10,414)	(10,645)
Gain (loss) on sale of assets	1	390	(2,270)
Selling, general and administrative expenses	(42,890)	(30,296)	(28,345)
Consolidated operating income	$ 194,585	$ 287,688	$ 243,734

Our significant plant production and other volumetric data were as follows for the periods indicated:

	FOR YEAR ENDED DECEMBER 31,		
	2002(1)	2001(1)	2000(1)
MBPD, Net			
Propylene Fractionation	55	31	33
Isomerization	84	80	74
NGL Fractionation	235	204	213
Equity NGL Production	73	63	72
Octane Enhancement	5	5	5
NGL and petrochemical pipelines (2)	1,357	453	367
BBtus per day, Net			
Natural gas pipelines	1,207	1,349	n/a
Equivalent MBPD, Net			
NGL, petrochemical and natural gas pipelines (3)	1,675	808	367

(1) Volumetric data shown in the table above reflect operating rates of the underlying assets for the periods in which we owned them
(2) In addition to NGL and petrochemical pipeline volumes, this operating statistic also includes NGL import and export volumes
(3) Aggregate pipeline volumes are shown on an energy-equivalent basis where 3.8 MMBtus of natural gas throughput are equivalent to one barrel of NGL throughput

The following table illustrates selected average quarterly prices for natural gas, crude oil and selected NGL and petrochemical products since the first quarter of 2000:

	NATURAL GAS, $/MMBTU	CRUDE OIL, $/BARREL	ETHANE, $/GALLON	PROPANE, $/GALLON	NORMAL BUTANE, $/GALLON	ISOBUTANE, $/GALLON	POLYMER GRADE PROPYLENE, $/POUND	REFINERY GRADE PROPYLENE, $/POUND
	(a)	(b)	(a)	(a)	(a)	(a)	(a)	(a)
2000								
1st Quarter	$2.49	$28.84	$0.38	$0.54	$0.64	$0.64	$0.21	$0.17
2nd Quarter	$3.41	$28.79	$0.36	$0.52	$0.60	$0.68	$0.26	$0.24
3rd Quarter	$4.22	$31.61	$0.40	$0.60	$0.68	$0.67	$0.26	$0.18
4th Quarter	$5.22	$31.98	$0.49	$0.67	$0.75	$0.73	$0.24	$0.19
Average	$3.84	$30.31	$0.41	$0.58	$0.67	$0.68	$0.24	$0.19
2001								
1st Quarter	$7.05	$28.77	$0.49	$0.63	$0.70	$0.74	$0.23	$0.17
2nd Quarter	$4.65	$27.86	$0.37	$0.50	$0.56	$0.66	$0.19	$0.12
3rd Quarter	$2.90	$26.64	$0.27	$0.41	$0.49	$0.49	$0.16	$0.13
4th Quarter	$2.43	$21.04	$0.21	$0.34	$0.40	$0.39	$0.18	$0.13
Average	$4.26	$26.07	$0.33	$0.47	$0.54	$0.57	$0.19	$0.14
2002								
1st Quarter	$2.34	$21.41	$0.22	$0.30	$0.38	$0.44	$0.16	$0.12
2nd Quarter	$3.38	$26.26	$0.26	$0.40	$0.48	$0.51	$0.20	$0.17
3rd Quarter	$3.16	$28.30	$0.26	$0.42	$0.52	$0.58	$0.21	$0.16
4th Quarter	$3.99	$28.33	$0.31	$0.49	$0.60	$0.63	$0.20	$0.15
Average	$3.22	$26.08	$0.26	$0.40	$0.50	$0.54	$0.19	$0.15

(a) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including OPIS and CMAI
(b) Crude Oil price is representative of the index price for West Texas Intermediate

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

The following table shows our consolidated revenues, costs and expenses, and operating income for the years ended December 31, 2002 and 2001 (dollars in thousands):

	FOR YEAR ENDED DECEMBER 31,	
	2002	2001
Revenues	$ 3,584,783	$ 3,154,369
Costs and expenses	$ 3,425,451	$ 2,892,039
Operating income	$ 194,585	$ 287,688

Revenues for 2002 increased $430.4 million over those of 2001. The increase is primarily due to acquisitions we completed during 2002 such as the purchase of Mid-America and Seminole from Williams and Splitter III 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 the results of our commodity hedging activities. Operating income decreased $93.1 million primarily as a result of such changes.

Pipelines. Gross operating margin from our Pipelines segment was $214.9 million for 2002 compared to $96.6 million for 2001. On an energy-equivalent basis, net pipeline throughput volume for 2002 was 1,669 MBPD compared to 809 MBPD during 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. Another $10.5 million of the improvement in year-to-year gross operating margin results from 2002 including a full year's results of operations from Acadian Gas, whereas 2001 included only nine months. We acquired Acadian Gas in April 2001.

Fractionation. Gross operating margin from our Fractionation segment was $129.0 million for 2002 compared to $118.6 million for 2001. We expanded our propylene fractionation business in February 2002 with the acquisition of Splitter III from Diamond-Koch. Our propylene fractionation volumes increased to 55 MBPD during 2002 from 31 MBPD during 2001. Gross operating margin from these businesses increased $22.6 million year-to-year. Splitter III accounted for 25 MBPD of the increase in volumes and $24.7 million of the increase in gross operating margin. Our isomerization business posted a $4.6 million decrease in gross operating margin for 2002 when compared to 2001. 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). Lastly, gross operating margin from our NGL fractionation businesses decreased $8.1 million in 2002 when compared to 2001. 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 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.

Processing. Gross operating margin from our Processing segment 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. Also, gross operating margin from NGL marketing activities included in this segment 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. Also, gross operating margin for 2001 includes the $10.6 million expense we recorded related to 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.

As noted above, the $152.6 million decrease in commodity hedging results was the primary reason for the year-to-year decline in gross operating margin from this segment. In order to manage the risks associated with our Processing segment, we may enter into short-term, highly liquid commodity financial instruments to hedge our exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions. We have employed various hedging strategies to mitigate the effects of fluctuating commodity prices (primarily NGL and natural gas prices) on our earnings from Processing segment businesses.

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 market values of our equity NGL production. Throughout 2001, this strategy proved very successful (as the price of natural gas declined relative to our fixed positions) and was responsible for most of the $101.3 million in commodity hedging income we recorded during 2001.

In late March 2002, the effectiveness of this strategy was reduced due to an unexpected rapid increase in natural gas prices whereby the loss in the value of our fixed-price natural gas financial instruments was not offset by increased gas processing margins. Due to the inherent uncertainty surrounding natural gas prices at the time, we decided that it was prudent to exit this strategy, and we did so by late April 2002. The increased ineffectiveness of this strategy is the primary reason for the $51.3 million in commodity hedging losses recorded during 2002. A variety of factors influence whether or not our hedging strategies are successful. For additional information regarding our financial instrument portfolios, see Item 7A of this report.

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

Other. Gross operating margin from this segment decreased $3.2 million year-to-year primarily due to an increase in information technology-related facility support costs.

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.

Year ended December 31, 2001 compared to year ended December 31, 2000

The following table shows our consolidated revenues, costs and expenses, and operating income for the years ended December 31, 2001 and 2000 (dollars in thousands):

	FOR YEAR ENDED DECEMBER 31,	
	2001	2000
Revenues	$ 3,154,369	$ 3,049,020
Costs and expenses	$ 2,892,039	$ 2,829,405
Operating income	$ 287,688	$ 243,734

Revenues for 2001 increased $105.3 million over those of 2000. The increase in revenue is primarily due to the acquisition of Acadian Gas from Shell during 2001. The higher pipeline revenues were offset by a decline in NGL product prices during 2001 relative to 2000 which lowered revenues from our NGL marketing activities. Costs and expenses during 2001 were $62.6 million higher than 2000 primarily due to the addition of costs and expenses of acquired businesses offset by decreased NGL product purchase prices and improved results from commodity hedging activities. Operating income increased $44.0 million year-to-year primarily as a result of such changes.

Pipelines. Gross operating margin from our Pipelines segment was $96.6 million for 2001 compared to $56.1 million for 2000. On an energy equivalent basis, net pipeline throughput volume for 2001 was 809 MBPD compared to 367 MBPD during 2000. Of the $40.5 million increase in segment gross operating margin, $20.0 million is due to the addition of earnings from natural gas pipelines we acquired during 2001. Specifically, we acquired Acadian Gas from Shell in April 2001 and equity ownership interests in four Gulf of Mexico systems from El Paso in January 2001. The natural gas throughput on these systems accounted for 355 MBPD of the 442 MBPD increase in segment volumes, on an energy equivalent basis.

An additional $12.2 million of the year-to-year increase in segment gross operating margin is attributable to our Lou-Tex NGL pipeline, which was completed and began operations during the fourth quarter of 2000. Gross operating margin from our Houston Ship Channel NGL import facility and related HSC pipeline increased $5.2 million in 2001 due to a rise in commercial butane imports related to isobutane production. The increase in NGL import activity and related pipeline movements accounted for 63 MBPD of the year-to-year increase in segment volumes.

Fractionation. Gross operating margin from our Fractionation segment was $118.6 million for 2001 compared to $129.4 million for 2000. Our propylene fractionation volumes declined slightly in 2001 to 31 MBPD from 33 MBPD in 2000. Gross operating margin from propylene fractionation increased $0.3 million in 2001 over 2000 due to additional margins from BRPC, which did not commence operations until the third quarter of 2000. Our isomerization business posted an $8.4 million increase in gross operating margin during 2001 when compared to 2000. Isomerization volumes increased to 80 MBPD during 2001 from 74 MBPD during 2000. The increase in isomerization earnings is primarily due to certain of our isomerization fees being indexed to historical natural gas prices (which were higher in 2001 relative to 2000). Lastly, gross operating margin from our NGL fractionation business in 2001 declined $21.0 million from 2000 levels, primarily as a result of lower in-kind fees at Norco. In-kind fee arrangements expose us to commodity price risk in that our revenues are dependent upon NGL market prices, which were generally lower in 2001 as compared to 2000. NGL fractionation volumes decreased to 204 MBPD during 2001 from 213 MBPD during 2000. The year-to-year decrease in NGL fractionation volumes is primarily due to lower mixed NGL extraction rates at regional gas plants during early 2001, which in turn was caused by higher natural gas prices.

Processing. Gross operating margin from our Processing segment was $155.0 million for 2001 compared to $122.2 million for 2000. Our equity NGL production decreased 9 MBPD to 63 MBPD during 2001 versus 72 MBPD during 2000. The decrease in our equity NGL production rate is primarily due to less favorable gas processing economics during early 2001 caused by higher natural gas prices. Segment gross operating margin for 2001 includes $101.3 million of commodity hedging income, an increase of $74.5 million over such income in 2000. The increase in our commodity hedging income mitigated or exceeded the loss in value of our NGL production caused by commodity price movements during 2001. In addition, our NGL marketing activities benefited from unusually strong demand for propane and isobutane during early and mid-2001.

We are exposed to settlement risk (a form of credit risk) with the counterparties of our financial instruments. On all transactions where we are exposed to settlement risk, we analyze the counterparty's financial condition prior to entering an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. In December 2001, Enron North America (the counterparty to some of our commodity financial instruments) filed for protection under Chapter 11 of the U.S. Bankruptcy Code. As a result, we recorded a charge against earnings of $10.6 million for all 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.

Octane Enhancement. Our equity earnings from BEF were $5.7 million for 2001 compared to $10.4 million for 2000. The decrease in equity earnings is primarily due to lower MTBE and by-product prices in 2001. On a gross basis, BEF's MTBE production was 14 MBPD during 2001 and 2000.

Other. Gross operating margin from this segment decreased $1.5 million year-to-year primarily due to an increase in information technology-related facility support costs.

Selling, general and administrative expenses. These expenses increased to $30.3 million during 2001 compared to $28.3 million during 2000. The increase is primarily due to the additional staff and resources needed to support our expansion activities resulting from acquisitions and other business development.

Interest expense. Interest expense increased to $52.5 million during 2001 compared to $33.3 million during 2000. The increase is primarily due to debt obligations we incurred as a result of business acquisitions completed during 2001. In addition, income from our interest rate hedging activities (which is recorded as a reduction in interest expense) increased $3.2 million in 2001 when compared to 2000. The change in interest rate hedging results is primarily due to certain elections by counterparties during 2001 and a general decrease in interest rates.

General outlook for 2003

We expect our business to be affected by the following key trends and events during 2003. 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 a result of abnormally high natural gas prices during the first quarter of 2003, we anticipate that NGL extraction rates at natural gas processing plants will be reduced. High natural gas prices may result in the cost of energy consumed by our natural gas processing facilities exceeding the market value of NGLs they extract. During periods of unusually high natural gas prices, we discuss with natural gas producers possible ways to limit the unfavorable impact of these energy costs.

- The expected reduction in NGL extraction rates during the first quarter of 2003 may also result in lower pipeline throughput rates and NGL fractionation volumes.

- As a result of the lower NGL extraction rates noted above, the demand for and price of certain NGL products increased. We expect that gross operating margin for our Processing segment will benefit from these market price increases as NGL inventories held by our NGL marketing group are sold.

- The expansion of our Neptune gas processing facility (which began in October 2002) is expected to be complete during the fourth quarter of 2003. This expansion will increase Neptune's gross gas processing capacity from 0.3 Bcf/d to 0.65 Bcf/d and will increase our NGL production capacity by 25 MBPD.

- In late 2003, Starfish is scheduled to complete construction of a 41-mile Gulf of Mexico natural gas pipeline that will connect its Stingray pipeline to new sources of deepwater Gulf of Mexico natural gas production.

- In March 2003, we completed the purchase of the remaining 50% ownership interests in EPIK from Idemitsu. As a result of this acquisition, segment earnings from NGL export activities will increase beginning in the first quarter of 2003 as we consolidate 100% of this operation.

- We expect a modest decline in demand for isomerization services during 2003 as refiners reduce their MTBE production in advance of California's ban on MTBE (of which isobutane is a feedstock) which takes effect in January 2004. The decline in isobutane demand attributable to MTBE production may be offset by increased demand for isobutane in producing alkylate (which could act as a replacement gasoline additive in place of MTBE).

- As a result of California's switch from using MTBE in its clean fuels program to ethanol in January 2004, we expect that overall demand for MTBE over the course of 2003 will be weaker than in prior years. This development will probably lead to lower MTBE prices which in turn will affect our equity earnings from BEF.

OUR LIQUIDITY AND CAPITAL RESOURCES

As noted at the beginning of Item 7 of this report, the following represents a combined discussion of our liquidity and capital resources requirements and those of the Operating Partnership. Within this section, references to partnership equity pertains to limited partner interests issued by us, whereas references to debt pertains to those obligations entered into by our Operating Partnership.

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 and the issuance of additional partnership equity and public and 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.

Operating cash flows primarily reflect the effects of net income adjusted for depreciation and amortization, equity income and cash distributions from unconsolidated affiliates, fluctuations in fair values 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 including fluctuations in NGL and energy prices, competitive practices in the midstream energy industry and the impact of operational and systems 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 NGL products, increased competition from petroleum-based products due to pricing differences or other reasons, could have a negative impact on earnings and thus the availability of cash from operating activities. For a more complete discussion of these and other risk factors pertinent to our businesses, see Item 1 of this report.

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, 2002, we had approximately $2.2 billion outstanding under various debt agreements. On that date, total borrowing capacity under our commercial bank credit facilities was $500 million of which $176 million of capacity was available. For additional information regarding our debt, see "Our debt obligations" on page 44.

In February 2001, we filed a universal shelf registration with the SEC covering the issuance of an unspecified amount of partnership equity or public debt obligations (separately or in combination). In October 2002, we sold 9.8 million Common Units under this shelf registration which generated net proceeds to us of approximately $183.3 million before offering expenses. In January 2003, we sold an additional 14.7 million Common Units under this shelf registration which generated $258.9 million in net proceeds before offering expenses. We used net proceeds before offering expenses from both equity issues to reduce debt outstanding under our 364-Day Term Loan and for working capital purposes. Also, in January and February 2003, we completed the issuance of $850 million of private placement debt (Senior Notes C and D) that we expect to convert to public debt. For additional information regarding the general use of proceeds from the from Senior Notes C and D and the January 2003 equity offering, see our footnote titled "Subsequent Events" in the Notes to Consolidated Financial Statements under Item 8 of this annual report. In addition, please read the section titled "Our debt obligations" within this "Our liquidity and capital resources" discussion for information regarding 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 accordance with Rule 457(p) promulgated under the Securities Act of 1933, as amended, the registration fee associated with the unsold portion of the securities under the shelf registration statement filed in February 2001 was used to offset the registration fee due in connection with our $1.5 billion universal shelf registration statement. As a result, at the time our $1.5 billion shelf registration statement is declared effective by the SEC, the securities remaining under the shelf registration statement filed in February 2001 will be deemed deregistered.

We have the ability to issue an unlimited number of Common Units to finance acquisitions and capital improvements if Adjusted Operating Surplus (as defined within our partnership agreement) for each of the four fiscal quarters immediately preceding the expenditure, on a pro forma basis, would have increased as a result of such expenditure (i.e., would have been accretive on a pro forma basis for each of the quarters in the test). For those acquisitions and other transactions that do not qualify under the aforementioned pro forma "accretive" test, we have 54,550,000 Units available for general partnership purposes during the Subordination Period. The Subordination Period generally extends until the first day of any quarter beginning after June 30, 2003 when certain financial tests have been satisfied. After the Subordination Period expires, we may prudently issue an unlimited number of Units for general partnership purposes that do not meet the pro forma "accretive" test.

If deemed necessary, we believe that additional financing arrangements can be obtained at 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.

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. The following table summarizes the major components of operating cash flows for 2002 and 2001 (dollars in thousands):

	FOR YEAR ENDED DECEMBER 31,	
	2002	2001
Net income	$ 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	94,925	51,903
Equity in income of unconsolidated affiliates	(35,253)	(25,358)
Distributions received from unconsolidated affiliates	57,662	45,054
Non-cash changes in fair market value of financial instruments	10,213	(5,697)
Other	14,059	12,391
Cash flow from operating activities before changes in operating accounts	$ 237,106	$ 320,471
Net effect of changes in operating accounts	92,655	(37,143)
Operating activities cash flows	$ 329,761	$ 283,328

As shown in the table above, cash flow before changes in operating accounts was an inflow of $237.1 million during 2002 versus $320.5 million during 2001. We believe that cash flow from operating activities before changes in operating accounts is an important measure of our liquidity. We believe it provides an indication of our ability to generate core cash flows from the assets and investments we own or in which we have an interest. 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 see our footnote titled "Supplemental Cash Flows Disclosure" in the Notes to Consolidated Financial Statements 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. 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. 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 9.8 million new Common Units. Net proceeds before offering expenses from the sale of the Common Units were $183.3 million (from which offering expenses of approximately $0.8 million were paid). This amount includes the General Partner's aggregate contribution to us and our Operating Partnership of $3.6 million to maintain its combined 2% general partner interest. Cash distributions to our partners 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 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 issue costs increased $16.2 million year-to-year primarily due to the $15.0 million in fees we paid to banks in July 2002 associated with the short-term financing of the Mid-America and Seminole acquisitions.

Year ended December 31, 2001 compared to year ended December 31, 2000

Operating cash flows. Cash flow from operating activities was an inflow of $283.3 million during 2001 compared to $360.9 million during 2000. The following table summarizes the major components of operating cash flows for 2001 and 2000 (dollars in thousands):

	FOR YEAR ENDED DECEMBER 31,	
	2001	2000
Net income	$ 242,178	$ 220,506
Adjustments to reconcile net income to cash flows provided by (used for) operating activities before changes in operating accounts:		
Depreciation and amortization	51,903	41,045
Equity in income of unconsolidated affiliates	(25,358)	(24,119)
Distributions received from unconsolidated affiliates	45,054	37,267
Non-cash changes in fair market value of financial instruments	(5,697)	
Other	12,391	15,060
Cash flow from operating activities before changes in operating accounts	$ 320,471	$ 289,759
Net effect of changes in operating accounts	(37,143)	71,111
Operating activities cash flows	$ 283,328	$ 360,870

As shown in the table above, cash flow before changes in operating accounts was an inflow of $320.5 million during 2001 versus $289.8 million during 2000. The $30.7 million increase in this element of our operating cash flows was primarily due to improved commodity hedging results offset by an increase in interest expense. The $10.9 million increase in depreciation and amortization is primarily due to businesses we acquired during 2001. 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 see our footnote titled "Supplemental Cash Flows Disclosure" in the Notes to Consolidated Financial Statements under Item 8 of this annual report.

Investing cash flows. During 2001, we used $491.2 million in cash for investing activities compared to $268.8 million during 2000. 2001 reflects the $225.7 million paid to acquire Acadian Gas from Shell and $113.0 million paid to acquire equity interests in four Gulf of Mexico natural gas pipelines from El Paso. During 2001, our capital expenditures were $149.9 million compared to $243.9 for 2000. The majority of capital expenditures made during both periods were for projects within our Pipelines segment.

Financing cash flows. Our financing activities generated $279.5 million of cash receipts in 2001 compared to cash payments of $36.9 million in 2000. Net borrowings for 2001 reflect our issuance of Senior Notes B whereas 2000 includes the issuance of Senior Notes A and the MBFC Loan and the associated repayments on various commercial bank credit facilities. Cash distributions to our partners increased $25.0 million year-to-year primarily due to increases in both the declared quarterly distribution rates and the number of Units eligible for distributions. When compared to 2000, the number of Units eligible for distributions during 2001 increased due to the conversion of 10.0 million of Shell's Special Units to an equal number of Common Units in August 2001.

Our debt obligations

Our debt consisted of the following at (dollars in thousands):

	DECEMBER 31, 2002	DECEMBER 31, 2001
Borrowings under:		
364-Day Term Loan, variable rate, due July 2003	$ 1,022,000	
364-Day Revolving Credit facility, variable rate, due November 2004	99,000	
Multi-Year Revolving Credit facility, variable rate, due November 2005	225,000	
Senior Notes A, 8.25% fixed rate, due March 2005	$ 350,000	350,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	450,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 2005	45,000	
Total principal amount	2,245,000	854,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,774	1,653
Less unamortized discount on:		
Senior Notes A	(81)	(117)
Senior Notes B	(230)	(258)
Less current maturities of debt	(15,000)	-
Long-term debt	$ 2,231,463	$ 855,278

The table above does not reflect the issuance of our $350 million principal amount Senior Notes C in January 2003 and $500 million principal amount Senior Notes D in February 2003 nor does it reflect the repayment of debt using proceeds from our January 2003 equity offering. We used a combination of proceeds from the issuance of Senior Notes C and D and the January 2003 equity offering to completely repay the 364-Day Term Loan by the end of February 2003 (see the section titled "General description of debt--364-Day Term Loan" within this "Our debt obligations" discussion for additional information regarding the use of proceeds to extinguish this debt). In addition, also read the section titled "New debt obligations issued during first quarter of 2003" within this "Our debt obligations" discussion for information regarding our Senior Notes C and D.

As to the assets of our subsidiary, Seminole Pipeline Company, our $2.2 billion in senior indebtedness at December 31, 2002 is structurally subordinated and ranks junior in right of payment to the $45 million of indebtedness of Seminole Pipeline Company. 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, 2002 reflect the classification of such debt obligations at March 7, 2003.

Letters of credit. At December 31, 2002, we had a total of $75 million of standby letters of credit capacity under our Multi-Year Revolving Credit facility, of which $2.4 million was outstanding.

Parent-Subsidiary guarantor relationships. Enterprise Products Partners L.P. (the "MLP", on a stand-alone basis) acts as guarantor of certain of the Operating Partnership's debt obligations. These parent-subsidiary guaranty provisions exist under all of our debt obligations with the exception of the Seminole Notes. The Seminole Notes are unsecured obligations solely of Seminole Pipeline Company. If the Operating Partnership were to default on any guaranteed debt obligation, the MLP would be responsible for full payment of that obligation.

General description of debt

The following is a summary of the significant aspects of our debt obligations at December 31, 2002.

364-Day Term Loan. The Operating Partnership entered into a $1.2 billion senior unsecured 364-day term loan to fund the Mid-America and Seminole acquisitions in July 2002. We applied proceeds of $178.8 million from our October 2002 equity offering to partially repay this loan. We used $252.8 million of the $258.9 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 completely repay the 364-Day Term Loan by February 2003. Base variable interest rates under this facility generally bore interest at either (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent or (2) a Eurodollar rate. Whichever base interest rate we selected, the rate was increased by an appropriate applicable margin (as defined within the loan agreement). During 2002, the weighted-average interest rate charged was 3.1%. This facility contained various covenants similar to those of our revolving credit facilities. We were in compliance with these covenants at December 31, 2002.

364-Day Revolving Credit facility. In November 2000, we entered in a 364-Day revolving credit agreement. Currently, the stand-alone borrowing capacity under this credit facility is $230 million with the maturity date for any amount outstanding being November 2003. We have the option to convert any revolving credit balance outstanding at maturity to a one-year term loan (due November 2004) in accordance with the terms of the credit agreement. This credit facility is guaranteed by the MLP through an unsecured guarantee. In addition, our borrowings under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. We applied $60.0 million in proceeds from our February 2003 issuance of Senior Notes D to reduce the balance outstanding under this facility during 2003.

Variable interest rates charged under this facility generally bear interest at either (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent 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. During 2002, the weighted-average interest rate charged for borrowings under this facility was 2.5%.

The 364-Day Revolving Credit facility 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 quarter. As defined within 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, 2002.

Multi-Year Revolving Credit facility. In conjunction with the 364-Day Revolving Credit facility, we entered into a five-year revolving credit facility (the "Multi-Year Revolving Credit facility") that includes a sublimit capacity of $75 million for standby letters of credit. Currently, the stand-alone borrowing capacity under this credit facility is $270 million. This credit facility is guaranteed by the MLP through an unsecured guarantee. In addition, our borrowings under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. The interest rates charged under this facility are determined in the same manner as that described under our 364-Day Revolving Credit facility. During 2002, the weighted-average interest rate charged for borrowings under this facility was 2.4%.

This facility contains various covenants similar to those of our 364-Day Revolving Credit facility (please refer to our discussion regarding restrictive covenants of the "364-Day Revolving Credit facility" within this "General description of debt" section). We were in compliance with these covenants at December 31, 2002.

Senior Notes A and B. These fixed-rate notes are an unsecured obligation of the Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness and senior to any future subordinated indebtedness. Both notes are guaranteed by the MLP through an unsecured and unsubordinated guarantee and are non-recourse to the General Partner. These notes were issued under an indenture containing certain covenants and are subject to a make-whole redemption right. 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, 2002.

MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, we entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). This loan is subject to a make-whole redemption right and is guaranteed by MLP through an unsecured and unsubordinated guarantee. The indenture agreement for this loan contains an acceleration clause whereby the outstanding principal and interest on the loan may become due and payable within 120 days if our credit ratings decline below a Baa3 rating by Moody's (currently Baa2) and below a BBB- rating by Standard and Poors (currently BBB). Under these circumstances, the trustee (as defined within the loan agreement) may, and if requested to do so by holders of at least 25% of the principal amount of the underlying bonds, shall accelerate the maturity of the MBFC Loan, whereby the principal and all accrued and unpaid interest would become immediately due and payable. If such an event occurred, we would have the option of (1) to redeem the MBFC Loan or (2) to provide an alternate credit agreement to support our obligation under the MBFC Loan. We would have 120 days to exercise these options upon receiving notice of the decline in our credit ratings.

The MBFC Loan agreement contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility and restrictions regarding mergers. We were in compliance with these covenants at December 31, 2002.

Seminole Notes. As a result of our acquisition of 78.4% of Seminole in July 2002, we are required to consolidate its debt with our other debt obligations. At December 31, 2002, Seminole had $45 million in fixed-rate senior unsecured notes, of which $15 million is due annually each December through December 2005. The Seminole Notes contain various covenants, such as minimum net worth requirements and those restricting Seminole's ability to borrow additional funds. Seminole was in compliance with these covenants at December 31, 2002.

New debt obligations issued during first quarter of 2003

January 2003 Senior Notes Offering. In January 2003, we issued $350 million in principal amount of 6.375% Senior Notes due 2013 ("Senior Notes C"), from which we received net proceeds before offering expenses of approximately $347.7 million. 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.

February 2003 Senior Notes Offering. In February 2003, we issued $500 million in principal amount of 6.875% Senior Notes due 2033 ("Senior Notes D"), from which we received net proceeds before offering expenses of approximately $489.8 million. 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.

Credit ratings

Our current investment grade credit ratings are Baa2 by Moody's Investor Service and BBB by Standard and Poors. Upon our acquisitions of the Mid-America and Seminole pipelines, which were financed by the $1.2 billion 364-Day Term Loan, both agencies maintained our ratings; however, each placed us on negative outlook pending the issuance of an appropriate amount of equity. The agencies have responded positively to our recent equity and debt offerings. 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 which independently judge our creditworthiness based on a variety of quantitative and qualitative factors.

Cash requirements for future growth

Acquisitions. We are committed to the long-term growth and viability of the Company. Our strategy involves expansion through business acquisitions and internal growth projects. In recent years, major oil and gas companies have sold non-strategic assets in the midstream energy industry in which we operate. We forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestures. Management continues to analyze potential acquisitions, joint venture or similar transactions with businesses that operate in complementary markets and geographic regions. We believe that the Company is positioned to continue to grow through acquisitions that will expand its platform of assets and through internal growth projects. Our goal is to invest $500 million annually in such opportunities to the extent we believe such investments will be accretive to our Unitholders.

We expect that the funds needed to achieve this goal will be obtained through a combination of operating cash flows; public and private placement debt; and the issuance of partnership equity. Our $1.7 billion in business acquisitions and internal growth projects we completed during 2002 were initially funded with approximately $1.5 billion of debt. This will translate into increased debt service costs in the future. To the extent proceeds from future partnership equity offerings are used to reduce the principal amount of debt, our interest expense will be reduced. To the extent we refinance our existing debt with new debt, our interest expense will generally be affected by differences in interest rates charged on the existing debt versus the new debt and by any fees associated with the new debt.

Distributions. Another stated goal of management is to increase the distribution rate to our partners by at least 10% annually. At the end of 2002, the declared annual rate was $1.38 per Common Unit, which was 10.4% higher than the rate in effect at the end of 2001. An increase in our distribution rate will translate into additional cash payments to existing Unitholders. In addition, an increase in the number of Units eligible for cash distributions will result in higher payments. We issued 14.7 million new Common Units in January 2003 and expect to convert Shell's remaining 10.0 million Special Units to distribution-bearing Common Units in August 2003. Both of these transactions will have the effect of increasing cash distributions over those paid during 2002. On an annualized basis assuming a distribution rate of $1.38 per Common Unit, our distributions to partners would increase by $34.1 million as a result of these additional 24.7 million Common Units. We believe that all cash distributions will be paid out of operating cash flows over the long-term; however, from time to time, we may temporarily borrow under our debt agreements for the purpose of paying cash distributions until the full impact of our operations are realized.

Capital spending. At December 31, 2002, we had $7.8 million in estimated outstanding purchase commitments attributable to capital projects. Of this amount, $1.5 million is related to the construction of assets that will be recorded as property, plant and equipment and $6.3 million is associated with our share of capital projects of our unconsolidated affiliates which will be recorded as additional investments in unconsolidated affiliates.

During 2003, we expect capital spending on internal growth projects to approximate $110.2 million, of which $22.8 million is forecasted for various projects within our Pipelines segment; $38.6 million for the expansion of our Norco NGL fractionator and $40.0 million for the expansion of our Neptune gas processing facility. Our unconsolidated affiliates forecast a combined $63.1 million in capital expenditures during 2003, the majority of which relate to expansion projects on our Gulf of Mexico natural gas pipeline systems. Our share of these forecasted capital expenditures is estimated at $26.2 million.

At our formation, EPCO contributed various equipment leases to us for which they have retained the liability for the lease payments (the "retained leases"). These leases relate to an isomerization unit, a DIB tower, two cogeneration units and approximately 100 railcars. EPCO has assigned to us the purchase options associated with these leases. If we decide to exercise these purchase options (which are at fair market value), up to $26.0 million is expected to be payable in 2004, $3.4 million in 2008 and $3.1 million in 2016.

As a result of new regulations imposing stricter air emissions requirements on petrochemical production and similar facilities in the Houston-Galveston area, we are required to redesign and modify certain components of our Mont Belvieu facility to comply with these new Clean Air Act requirements. Based upon these newly approved regulations, we estimate capital expenditures of $25 to $30 million (in the aggregate) will be required to modify our Mont Belvieu facilities. Through December 31, 2002, we spent $0.2 million related to this project. We forecast to spend between two and three million dollars for such modifications during 2003. The remaining amount is expected to be spent between 2004 and 2007. For additional information regarding these new regulations, see "Business and Properties--Regulation and Environmental Matters--General Impact of the Clean Air Act on our operations" under Items 1 and 2 of this annual report.

SUMMARY OF MATERIAL CONTRACTUAL OBLIGATIONS

The following table summarizes our material contractual obligations at December 31, 2002 (dollars in thousands, volumes as stated):

CONTRACTUAL OBLIGATIONS	TOTAL	2003	2004 THROUGH 2005	2006 THROUGH 2007	AFTER 2007
Scheduled principal payments to be made under debt obligations	$ 2,245,000	$ 1,037,000	$ 704,000		$ 504,000
Potential payments under letter of credit agreements	$ 2,400		$ 2,400		
Payments due under operating leases	$ 17,793	$ 7,148	$ 5,840	$ 1,182	$ 3,623
Capital expenditure commitments	$ 7,797	$ 7,797			
Long-term purchase commitments: (Expressed in terms of minimum volumes under contract per period:)					
NGLs (MBbls)	60,848	15,986	22,752	11,310	10,800
Petrochemicals (MBbls)	82,096	25,428	42,144	14,524	
Natural gas (BBtus)	190,282	23,053	39,084	36,895	91,250

Our scheduled principal payments reflect consolidated amounts due under public and private placement debt obligations. Total principal amount outstanding under debt obligations as shown in the table above does not reflect the issuance of our $350 million Senior Notes C in January 2003 (due 2013) and $500 million Senior Notes D in February 2003 (due 2033) nor does it reflect the complete repayment of the 364-Day Term Loan in February 2003. Our potential payments under letter of credit agreements are associated with our purchase of hydrocarbon imports and the guarantee of our share of Evangeline's debt service reserve requirements. For additional information regarding our debt obligations, please see "Our debt obligations" on page 44 of this annual report.

We lease certain equipment and processing facilities under noncancelable and cancelable operating leases. The payments due under these leases (as shown above) represent our minimum future rental payments. The operating lease commitments shown above 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").

We routinely invest in capital projects of our own and in those of our unconsolidated affiliates. The amount shown above reflects the committed expenditures under these projects at December 31, 2002. Lastly, we have long-term purchase commitments for NGLs, petrochemicals and natural gas with several suppliers. In general, the purchase prices contained within these supply contracts approximate market prices at the time we take delivery of the volumes.

RECENT ACCOUNTING DEVELOPMENTS

We adopted SFAS No. 142, "Goodwill and Other Intangible Assets", on January 1, 2002. This standard establishes accounting standards for all goodwill and other intangible assets recognized in our consolidated balance sheet. In addition, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" on January 1, 2002. This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. For information regarding our goodwill, intangible assets and long-lived assets, please see the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

We adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," on January 1, 2003. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation ("ARO") and the associated asset retirement cost. An ARO exists when a company determines that it has a clearly defined legal obligation upon retirement of a long-lived asset or any component part thereof and that the legal obligation will lead to the future payment of funds to a third party upon retirement of the asset. In general, legal obligations underlying AROs result from enacted laws and regulations or from contractual provisions related to long-lived assets. AROs can also arise through the normal course of operating a long-lived fixed asset.

An ARO liability will be recorded on the balance sheet if a reasonable estimate of fair value of the obligation can be made. Our estimate of fair value for each ARO is primarily dependent upon a clearly defined plan of retirement (dates, methods, etc.) and costs associated with the retirement activity. If a reasonable estimate cannot be made (i.e., no current or required plans for retirement of the asset, etc.), footnote disclosure is required but the ARO is not recorded until a reasonable estimate can be made. Any earnings impact resulting from the recognition of an ARO upon adoption of SFAS No. 143 should be reflected as the cumulative effect of a change in accounting principle.

Upon adoption of SFAS No. 143, we reviewed our long-lived assets for ARO's by segment. We identified, but have not recognized, ARO liabilities in several operational areas. These include ARO liabilities related to easements over property not currently owned by us. Our rights to the easements are renewable and only require retirement action upon nonrenewal of the easement agreements. We currently plan to renew all such easement agreements and use these properties indefinitely. Therefore, the ARO liability is not estimable for such easements. If we decide not to renew these agreements, an ARO liability would be recorded at that time.

ARO liabilities related to statutory regulatory requirements for abandonment or retirement of certain currently operated facilities were also identified. 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 occurred.

Certain Gulf of Mexico natural gas pipelines, in which we have an equity interest, have identified ARO's relating to regulatory requirements. There is no current intention to abandon or retire these pipelines. If these pipelines were abandoned or retired, an ARO liability would then be disclosed.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." This standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operations, plant closing, or other exit or disposal activity. Previous accounting guidance was provided by EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 replaces Issue 94-3. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002. We adopted this statement on January 1, 2003 and determined that it had no material impact on our financial statements.

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements from Guarantees, Including Indirect Guarantees of Indebtedness of Others". 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. The initial recognition and measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements in this interpretation are applicable for financial statements of interim or annual periods after December 15, 2002. See "Our debt obligations" on page 44 for the disclosure of Parent-Subsidiary guarantor relationships.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure," which 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 in both annual and interim financial statements. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002, and financial reports containing condensed financial statements for interim periods beginning after December 15, 2002. EPCO has stock-based employee compensation plans for which we have a funding commitment for certain employees. We do not believe that the adoption of this statement will have a 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. Examples of these estimates and assumptions include depreciation methods and estimated lives of property, plant and equipment, amortization methods and estimated lives of qualifying intangible assets, methods employed to measure the fair value of goodwill, revenue recognition policies and mark-to-market accounting procedures. The following describes the estimation risk in each of these significant financial statement items:

- 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 35 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. Additionally, if we determine that an asset's undepreciated cost may not be recoverable due to economic obsolescence, the business climate, legal or other factors, we would review the asset for impairment and record any necessary reduction in the asset's value as a charge against earnings. At December 31, 2002 and 2001, the net book value of our property, plant and equipment was $2.8 billion and $1.3 billion, respectively.

- 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 (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.

  At December 31, 2002, our significant intangible assets consisted of the following (along with unamortized balances of each group at that date):

  - the Shell natural gas processing agreement that we acquired as part of the TNGL acquisition in August 1999 ($183.2 million);

  - certain storage and propylene fractionation contracts we acquired in connection with the Diamond-Koch acquisitions in January and February 2002 ($59.5 million); and

  - certain natural gas processing and NGL fractionation contracts we acquired in connection with the Toca-Western acquisition in June 2002 ($30.3 million).

The Shell natural gas processing agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term. The propylene fractionation and storage contracts acquired from Diamond-Koch are being amortized on a straight-line basis over the economic life of the assets to which they relate, which is currently estimated at 35 years. The Toca-Western natural gas processing contracts are being amortized on a straight-line basis over the expected 20-year remaining life of the natural gas supplies supporting these contracts. The Toca-Western NGL fractionation contracts are being amortized on a straight-line basis over the expected 20-year remaining life of the assets to which they relate.

If the underlying assumption(s) governing the amortization of an intangible asset were later determined to have significantly changed (either favorably or unfavorably), we then might need 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 then might need to reduce its carrying value and subsequent useful life. 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. During 2002, we did not recognize any impairment losses related to our intangible assets.

- Goodwill. At December 31, 2002, the recorded value of goodwill was $81.5 million. 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 on January 1, 2002, our goodwill amounts are no longer amortized. Instead, goodwill is tested at a reporting unit level annually, and 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.), the fair value of the reporting unit, including its related goodwill, is calculated and compared to its combined book value. Currently, all of our goodwill is recorded as part of the Fractionation operating segment (based on the assets to which the goodwill relates).

  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.

- Revenue recognition. 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. The revenues that we record are not materially based on estimates. We believe the assumptions underlying any revenue estimates that we might use will not prove to be significantly different from actual amounts due to the routine nature of these estimates and the stability of our operations. Of the contracts that we enter into with customers, the majority fall within five main categories as described below:

  - Tolling (or throughput) arrangements where we process or transport customer volumes for a cash fee (usually on a per gallon or other unit of measurement basis);

  - Product sales contracts where we sell products to customers at market-related prices for cash;

  - Storage agreements where we store volumes or reserve storage capacity for customers for a cash fee; and

  - Fee-based marketing services where we market volumes for customers for either a percentage of the final cash sales price or a cash fee per gallon handled.

A number of tolling arrangements are utilized in our Fractionation and Pipeline segments. Examples include NGL fractionation, isomerization and pipeline transportation agreements. Typically, we recognize revenue from tolling arrangements once contract services have been performed. At times, the tolling fees we or our affiliates charge for pipeline transportation services are regulated by such governmental agencies as the FERC. At certain of our NGL fractionation facilities, an in-kind tolling arrangement is utilized. An in-kind 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. Fractionation revenue is recognized and recorded on a monthly basis for transfers of "in-kind" retained NGL products to the NGL working inventory maintained within our Processing 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 Processing segment is eliminated in our reporting of consolidated revenues and expenses.

Our Processing segment activities employ tolling and product sales contracts. If a customer pays us a cash tolling fee for our natural gas processing services, we record revenue to the extent that natural gas volumes have been processed and sent back to the producer. If the natural gas processing contract stipulates that we retain a percentage of the extracted NGLs as payment for our services, revenue is recognized and recorded when the extracted NGLs are delivered out of our inventory and sold to customers on sales contracts. Our NGL marketing activities within this segment also use product sales contracts to sell and deliver out of inventory the NGLs transferred to it as a result of the Fractionation segment's in-kind 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. In addition to the Processing segment, product sales contracts are utilized in the Fractionation segment to record revenues from the sale of petrochemical products and in the Pipelines segment to record revenues from the sale of natural gas. Pricing terms in our product sales contracts are based upon market-related prices for such products and can include pricing differentials due to factors such as differing delivery locations.

- Fair value accounting for commodity financial instruments. Our earnings are also affected by use of the mark-to-market method of accounting required under GAAP 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 Processing segment. As of December 31, 2002, none of our commodity financial instruments qualify for hedge accounting treatment and thus the changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the firm commitment or anticipated transaction affects earnings. 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 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.

  For the year ended December 31, 2002, we recognized losses from our commodity hedging activities of $51.3 million. Of this loss, $5.6 million is attributable to the negative change in market value of the commodity hedging portfolio since December 31, 2001 using the mark-to-market method of accounting for our financial instruments. The fair value of our commodity financial instrument portfolio at December 31, 2002 was a payable of $26 thousand, based upon quoted market prices. At that date, we had a limited number of open positions that extend through December 2003. 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, see the Processing segment discussion under "Our results of operations" within this Item 7 and also read Item 7A of this annual report.

Additional information regarding our financial statements and those of the Operating Partnership can be found in the Notes to Consolidated Financial Statements of each entity included elsewhere in this Form 10-K.

RELATED PARTY TRANSACTIONS

Relationship with EPCO and Its Affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates. EPCO is majority-owned and controlled by Dan L. Duncan, Chairman of the Board and a director of the General Partner. In addition, three other members of the Board of Directors (O.S. Andras, Randa D. Williams and Richard H. Bachmann) and the remaining executive and other officers (see Item 10 for a listing of these individuals) of the General Partner are employees of EPCO. The principal business activity of our General Partner is to act as our managing partner. Collectively, EPCO and its affiliates (which includes the 1998 Trust, 2000 Trust and Dan L. Duncan) owned 61.4% of our limited partnership interests and 70.0% of our General Partner at December 31, 2002.

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the EPCO Agreement (see Item 13). We reimburse EPCO for the costs of its employees who perform operating functions for us. In addition, we reimburse EPCO for the costs of certain of employees who manage our business and affairs.

EPCO is also the operator of certain facilities we own or have an equity interest in. We have also entered into an agreement with EPCO to provide trucking services to us for the loading and transportation of products. Lastly, in the normal course of business, we buy from and sell NGL products to EPCO's Canadian affiliate.

During 2002, our related party revenues from EPCO were $3.6 million and our related party expenses with EPCO were $127.4 million. For additional information regarding our relationship with EPCO, see Item 13 of this annual report.

Relationship with Shell

We have an extensive and ongoing commercial relationship with Shell as a partner, customer and vendor. Shell currently owns approximately 20.5% of our limited partnership interests and 30.0% of our General Partner. Currently, three members of the Board of Directors of the General Partner (J.A. Berget, J.R. Eagan and A.Y. Noojin, III) are employees of Shell.

Shell and its affiliates are the Company's single largest customer. During 2002, they accounted for 7.8% of our consolidated revenues. Our revenues from Shell reflect the sale of NGL and petrochemical products to them and the fees we charge them 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 (see the "Processing" segment discussion under Item 1 of this annual report) and the purchase of NGL products from them. During 2002, our related party revenues from Shell were $282.8 million and our related party expenses with Shell were $531.7 million.

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 $528.8 million (this purchase price includes both the $166 million in cash we paid to Shell and the value of the three issues of Special Units granted to Shell in connection with this acquisition);

- the purchase of the Lou-Tex Propylene Pipeline System 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 the Gulf of Mexico natural gas pipelines we acquired from El Paso in 2001. We also lease from Shell its 45.4% interest in our Splitter I propylene fractionation facility.

OTHER ITEMS

Uncertainties regarding our investment in facilities that produce MTBE

We have a 33.3% ownership interest in BEF, which owns a facility currently producing MTBE. At December 31, 2002, the carrying value of our investment in BEF was $54.9 million. Our equity earnings from BEF (which are recorded under our Octane Enhancement segment) were $8.5 million, $5.7 million and $10.4 million during 2002, 2001 and 2000, respectively. 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. Although these detections have been limited and the great majority have been well below levels of public health concern, there have been calls for the phase-out of MTBE in motor gasoline in various federal and state governmental agencies and advisory bodies. BEF has not been named in any MTBE legal action to date. For additional information regarding the impact of environmental regulation on BEF, see "Business and Properties--Regulation and Environmental Matters--Impact of the Clean Air Act's oxygenated fuels programs on our BEF investment" under Item 1 of this annual report.

During 2000, the city of Santa Monica brought suit against seven major oil companies and eleven other manufacturers, suppliers, refiners and pipeline operators alleging the defendants had tainted much of the city's drinking water supply with MTBE. In mid-July 2002, the city settled with two of the major oil companies. Under the terms of this settlement, the two defendants agreed to pay to design, build and operate a facility to treat the city's water (at a cost of approximately $200 million) and to pay $30 million in other damages. The court agencies involved in this case are reviewing this settlement. The city is still pursuing legal action against the remaining defendants.

In April 2002, a jury in California found three energy companies liable for polluting Lake Tahoe's drinking water with MTBE. While this decision sets no legal precedent, this was the first time that a jury has defined gasoline containing MTBE to be a "defective product". In August 2002, two of the defendants were ordered to pay $28 million to a Lake Tahoe-area utility district. The third defendant settled out of court for $4 million in July 2002.

In light of these developments, we and the other two owners of BEF are actively compiling a contingency plan for the BEF facility should MTBE be banned. We are currently evaluating a possible conversion of the facility from MTBE production to alkylate production. In addition to MTBE's value in reducing air pollution, it is a significant source of octane in the U.S. motor gasoline pool. Octane is a critical component of motor gasoline. Therefore, we believe that if MTBE usage is banned or significantly curtailed, the motor gasoline industry would need a substitute additive to maintain octane levels in gasoline and that alkylate would be an economic and effective substitute. We are currently conducting a detailed engineering study that is expected to be completed by the end of 2003, at which time we expect a more definitive conversion cost estimate will be available. The cost to convert the facility will depend on the type of alkylate process chosen and the level of production desired by the partnership.

Two-for-one split of Limited Partner Units

On February 27, 2002, we announced that the Board of Directors of the General Partner had approved a two-for-one split for each class of our Units. The partnership Unit split was accomplished by distributing one additional partnership Unit for each partnership Unit outstanding to holders of record on April 30, 2002. The Units were distributed on May 15, 2002. All references to number of Units or earnings per Unit contained in this document relate to the post-split Units, except if indicated otherwise.

Conversion of EPCO Subordinated Units and Shell Special Units to Common Units

As a result of the Company satisfying certain financial tests, 10,704,936 (or 25%) of EPCO's Subordinated Units converted to Common Units on May 1, 2002. If the financial criteria continue to be satisfied through the first quarter of 2003, an additional 25% of the Subordinated Units will undergo an early conversion on a one-for-one basis to Common Units on May 1, 2003. The remaining 50% of Subordinated Units will convert on August 1, 2003 if the balance of the conversion requirements are met. Subordinated Units have limited voting rights until converted to Common Units. The conversion(s) will have no impact upon our distributions or earnings per unit since the Subordinated Units are already distribution-bearing and included in both the basic and fully diluted calculations.

In accordance with existing agreements with Shell, 19.0 million of Shell's non-distribution bearing Special Units converted to distribution-bearing Common Units on August 1, 2002. The remaining 10.0 million Special Units will convert to Common Units on a one-for-one basis in August 2003. These conversions have a dilutive impact on basic earnings per Unit since they increase the number of Common Units used in the computation. As a result of the August 2002 conversion of the Shell Special Units to an equal number of Common Units, our basic earnings per Unit for 2002 were reduced by $0.03. Special Units are excluded from the computation of basic earnings per Unit because, under the terms of the Special Units, they do not share in income nor are they entitled to cash distributions until they are converted to Common Units.

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 Processing 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, see the Notes to our Consolidated Financial Statements.

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 Processing 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 Fractionation segment. In our Pipelines 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. 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 Other 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 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, 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 (values in thousands of dollars):

SCENARIO	RESULTING CLASSIFICATION	AT 12/31/01	AT 12/31/02	AT 03/03/03
FV assuming no change in quoted market prices	Asset (Liability)	$ 6,786	$ (26)	$ 84
FV assuming 10% increase in quoted market prices	Asset (Liability)	$ 844	$ (26)	$ 380
IE assuming 10% increase in quoted market prices	Income (Loss)	$(5,942)	$ -	$ 296
FV assuming 10% decrease in quoted market prices	Asset (Liability)	$ 12,599	$ (26)	$(211)
IE assuming 10% decrease in quoted market prices	Income (Loss)	$ 5,813	$ -	$(295)

At December 31, 2001, the net fair value of our commodity financial instruments portfolio was a $6.8 million asset, almost all of which was based upon quoted market prices. At December 31, 2002, the net fair value of this portfolio was a payable of $26 thousand, based entirely upon quoted market prices. Due to commodity hedging losses we incurred during the first quarter of 2002, we exited most of our positions (see our Processing segment discussion under "Our results of operations" in Item 7). At December 31, 2002, we had a limited number of commodity financial instruments outstanding. The fair value of the portfolio at March 3, 2003 was a $84 thousand asset and was again comprised of a limited number of positions.

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.

Product purchase commitments. We have long-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.

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. 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. We believe that it is prudent to maintain an appropriate balance of variable-rate and fixed-rate debt.

The following table shows the effect of hypothetical price movements on the fair value ("FV") of our interest rate swap portfolio and the related potential impact on our earnings ("IE") at the dates indicated (values in thousands of dollars):

SCENARIO	RESULTING CLASSIFICATION	AT 12/31/01	AT 12/31/02
FV assuming no change in quoted market prices	Asset (Liability)	$ 3,531	$ 1,634
FV assuming 10% increase in quoted market prices	Asset (Liability)	$ 3,345	$ 1,634
IE assuming 10% increase in quoted market prices	Income (Loss)	$ (186)	$ -
FV assuming 10% decrease in quoted market prices	Asset (Liability)	$ 3,717	$ 1,634
IE assuming 10% decrease in quoted market prices	Income (Loss)	$ 186	$ -

At December 31, 2002 and 2001, we had one interest rate swap outstanding having a notional amount of $54 million that extended through March 2010. Under the terms of the swap, the counterparty had the right to terminate the swap on March 1, 2003. The fair value of this swap was a $3.5 million asset at December 31, 2001. The fair value of this swap at December 31, 2002 was $1.6 million. The change in fair value of this swap during 2002 is primarily due to settlements. A change in interest rates at December 31, 2002 would have negligible effect on the fair value of this swap. The counterparty elected to terminate this swap as of March 1, 2003 and we received $1.6 million associated with the final settlement of this swap on that date.

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.

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 are 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 by early February 2003 in connection with our issuance of Senior Notes C and D (see "Management's Discussion and Analysis of Financial Condition and Results of Operations--Our liquidity and capital resource--Our debt obligations" under Item 7 of this annual report). The settlement of the treasury locks resulted in our receipt of $5.4 million of cash.

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 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 will be 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 our footnote titled "Financial Instruments" in the Notes to Consolidated Financial Statements under Item 8 of this annual report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The information for both registrants required hereunder is included in this report as set forth in the "Index to Financial Statements" beginning on page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF OUR REGISTRANTS.

As is commonly the case with publicly-traded limited partnerships, we do not directly employ any of the persons responsible for the management or operations of our business. These functions are performed by the employees of EPCO (pursuant to the EPCO Agreement, see page 69) under the direction of the Board of Directors and executive officers of the General Partner.

Notwithstanding any limitation on its obligations or duties, our General Partner is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to the General Partner. Whenever possible, the General Partner intends to make any such indebtedness or other obligations non-recourse to it.

Audit and Conflicts Committee

In accordance with NYSE rules, the Board of Directors of the General Partner has named three of its members to serve on its Audit and Conflicts Committee. The members of the Audit and Conflicts Committee are independent nonexecutive directors, free from any relationship with the Company or any of its subsidiaries that would interfere with the exercise of independent judgment. The Audit and Conflicts Committee has the authority to review specific matters as to which the Board of Directors believes there may be a conflict of interests in order to determine if the resolution of such conflict proposed by the General Partner is fair and reasonable to the Company. Any matters approved by the Audit and Conflicts Committee are conclusively deemed to be fair and reasonable to our business, approved by all of our partners and not a breach by the General Partner or its Board of Directors of any duties they may owe us or our Unitholders.

The members of the Audit and Conflicts Committee must have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements, and at least one member of the committee shall have accounting or related financial management expertise. Richard S. Snell, a certified public accountant, has been named by the Board of Directors of the General Partner as the independent financial expert serving on the Audit and Conflicts Committee. The other two members of the Audit and Conflicts Committee are Dr. Ralph S. Cunningham and Lee W. Marshall, Sr.

In addition to ruling in cases involving conflicts of interest, the primary responsibilities of the Audit and Conflicts Committee include:

- monitoring the integrity of the financial reporting process and its related systems of internal control;
- ensuring legal and regulatory compliance of the General Partner and the Company;
- overseeing the independence and performance of our independent public accountants;
- approving all services performed by our independent public accountants;
- providing for an avenue of communication among the independent public accountants, management, internal audit function and the Board of Directors;
- encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels;
- reviewing areas of potential significant financial risk to our businesses; and
- approving increases in the administrative service fee payable under the EPCO Agreement.

Pursuant to its formal written charter adopted in June 2000, the Audit and Conflicts committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to the independent public accountants as well as EPCO personnel. The Audit and Conflicts Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Directors, Executive Officers of the General Partner

Set forth below is the name, age and position of each of the directors and executive officers of the General Partner. Each member of the Board of Directors serves until such member's death, resignation or removal. The executive officers are elected for one-year terms and may be removed, with or without cause, only by the Board of Directors.

NAME	AGE	POSITION WITH GENERAL PARTNER
Dan L. Duncan (1,3)	70	Director and Chairman of the Board
O.S. Andras (1,3)	67	Director, President and Chief Executive Officer
Richard H. Bachmann (1,3)	50	Director, Executive Vice President, Chief Legal Officer and Secretary
Michael A. Creel (3)	49	Executive Vice President and Chief Financial Officer
A.J. Teague (3)	58	Executive Vice President
William D. Ray (3)	67	Executive Vice President
Charles E. Crain (3)	69	Senior Vice President
A. Monty Wells (3)	57	Senior Vice President
W. Ordemann (3)	43	Senior Vice President
Gil H. Radtke (3)	42	Senior Vice President
James M. Collingsworth (3)	48	Senior Vice President
James A. Cisarik (3)	45	Senior Vice President
Michael J. Knesek (3)	48	Vice President, Controller and Principal Accounting Officer
W. Randall Fowler (3)	46	Vice President and Treasurer
Randa D. Williams	41	Director
J.R. Eagan	48	Director
J.A. Berget (1)	50	Director
Dr. Ralph S. Cunningham (2)	62	Director
A. Y. Noojin, III (1)	55	Director
Lee W. Marshall, Sr. (2)	70	Director
Richard S. Snell (2)	60	Director

(1) Member of Executive Committee
(2) Member of Audit and Conflicts Committee
(3) Executive Officer

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

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

O.S. Andras was elected President, Chief Executive Officer and a Director of our General Partner in April 1998. Mr. Andras served as President and Chief Executive Officer of EPCO from 1996 to February 2001 and currently serves as Vice Chairman of the Board of EPCO. Mr. Andras devotes approximately 80% of his time to our business and affairs.

Richard H. Bachmann was elected a Director of our General Partner in June 2000. He has served as Executive Vice President, Chief Legal Officer and Secretary of our General Partner and EPCO since January 1999. Previously, he was a partner with the Snell & Smith P.C. law firm in Houston, Texas, from 1993 to 1999 and prior to that was a partner with the Butler & Binion law firm in Houston from 1988 to 1993. Mr. Bachmann devotes approximately 60% of his time to our business and affairs.

Michael A. Creel was elected an Executive Vice President of our General Partner and EPCO in February 2001, having served as a Senior Vice President of our General Partner and EPCO since November 1999. In June 2000, Mr. Creel, a certified public accountant, assumed the role of Chief Financial Officer of our General Partner and EPCO along with his other responsibilities. Previously, he served with Tejas Energy, LLC, a Shell affiliate, as Senior Vice President-Finance from 1997 to 1998, Senior Vice President, Chief Financial Officer and Treasurer from 1998 to 1999 and Senior Vice President from January to September 1999. From 1995 to 1997, Mr. Creel was Vice President and Treasurer of NorAm Energy Corp. Mr. Creel devotes approximately 55% of his time to our business and affairs.

A.J. Teague was elected an Executive Vice President of our General Partner in November 1999. From 1998 to 1999 he served as President of Tejas Natural Gas Liquids, LLC, then a Shell affiliate, and from 1997 to 1998 was President of Marketing and Trading for MAPCO, Inc.

William D. Ray was elected an Executive Vice President of our General Partner in April 1998. Mr. Ray served as EPCO's Executive Vice President of Supply and Marketing from 1985 to 1998. Mr. Ray continues to hold managerial responsibilities with respect to EPCO but devotes in excess of 95% of his time to our business and affairs.

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

A. Monty Wells was elected a Senior Vice President of our General Partner in June 2000 after serving as Manager - Marketing and Supply since 1998. Mr. Wells joined EPCO in 1980, and served as Manager of Marketing and Supply from 1990 to 1999 and Vice President of Marketing and Supply from 1999 to 2000.

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

Gil H. Radtke was elected a Senior Vice President of our General Partner in February 2002. Mr. Radtke joined us in connection with our purchase of Diamond-Koch's storage and propylene fractionation assets in January and February 2002. Before joining us, Mr. Radtke served as President of the Diamond-Koch joint venture from 1999 to 2002, where he was responsible for its storage, propylene fractionation, pipeline and NGL fractionation businesses. From 1997 to 1999 he was Vice President, Petrochemicals and Storage of Diamond-Koch. Mr. Radtke was previously employed by Ultramar Diamond-Shamrock Corporation (a partner in the Diamond-Koch joint venture) beginning in 1983.

James M. Collingsworth joined us as a Vice President in November 2001 and was elected a Senior Vice President of our General Partner in November 2002. Previously, he served as a board member of Texaco Canada Petroleum Inc. from July 1998 to October 2001 and was employed by Texaco from 1991 to 2001 in various management positions, including Senior Vice President of NGL Assets and Business Services from July 1998 to October 2001. Prior to joining Texaco, Mr. Collingsworth was director of feedstocks for Rexene Petrochemical Company from 1988 to 1991 and served previously in the MAPCO, Inc. organization from 1973 to 1988 in various capacities including customer service and business development manager of the Mid-America and Seminole pipelines.

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

Texas and Louisiana natural gas pipeline systems. Prior to his employment at Tejas Energy, LLC, he was employed from 1983 to 1997 by Tejas Gas Corporation and other previous owners of Acadian Gas.

Michael J. Knesek was elected Principal Accounting Officer and a Vice President of our General Partner in August 2000. Since 1990, Mr. Knesek, a certified public accountant, has been the Controller and a Vice President of EPCO. Mr. Knesek devotes approximately 70% of his time to our business and affairs.

W. Randall Fowler joined us as Director of Investor Relations in January 1999 and was elected to the additional positions of Treasurer and a Vice President of our General Partner and EPCO in August 2000. From May 1995 to December 1997, Mr. Fowler served as an Assistant Treasurer at NorAm Energy Corp. From January 1998 through December 1998, Mr. Fowler served as Director of Finance for Reliant Energy. Mr. Fowler devotes approximately 90% of his time to our business and affairs.

Randa D. Williams was elected a Director of our General Partner in April 1998. In February 2001, she was promoted to President and Chief Executive Officer of EPCO from her previous position of Group Executive Vice President of EPCO, a position she had held since 1994. Ms. Williams is the daughter of Dan L. Duncan.

J.R. Eagan was elected a Director of our General Partner in October 2000. Ms. Eagan has served in various executive-level positions with Shell, and since February 2002 she has held the office of Chief Financial Officer of Shell Oil Company and Vice President Finance & Commercial Operations of Shell Exploration and Production Company. From January 2000 to January 2002 she served as Vice President, Finance & Commercial Operations of Shell Exploration and Production Company. From January 1999 to December 1999 she was Vice President Finance of Shell Exploration and Production Company. From January 1998 to October 1998 she was Deputy Group Controller of Shell International Limited.

J.A. Berget was elected a Director of our General Partner in November 2000. Since 1995, Mr. Berget has served in various managerial capacities with the Royal Dutch/Shell Group of Companies, including General Manager of the Brent Business Unit of Shell U.K. from January 1997 to March 1999, General Manager, New Markets of the Brent Business Unit of Shell U.K. from March 1999 to October 2000 and Vice President and General Manager of Shell Exploration and Production Company from October 2000 to the present. Mr. Berget also serves as a director of Enventure Global Technologies (a joint venture between Shell and Halliburton Company).

Dr. Ralph S. Cunningham was elected a Director of our General Partner in April 1998. Dr. Cunningham retired in 1997 from CITGO Petroleum Corporation, where he had served as President and Chief Executive Officer since 1995. Dr. Cunningham serves as a director of Tetra Technologies, Inc. (a publicly traded energy services and chemicals company) and Agrium, Inc. (a Canadian publicly traded agricultural chemicals company) and was a director of EPCO from 1987 to 1997. Dr. Cunningham serves as Chairman of our Audit and Conflicts Committee.

A. Y. Noojin, III, was elected a Director of our General Partner in May 2002. Mr. Noojin became President and Chief Executive Officer of Shell U.S. Gas & Power, LLC, an affiliate of Shell, in May 2002. Previously, he served as President and Chief Executive Officer of Shell Oil Products Company from October 2000 to May 2002, Executive Vice President of Shell Chemicals Company from January 1998 to September 2000, and Vice President - Transportation of Shell Oil Products Company from January 1996 to December 1997.

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

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

Section 16(a) Beneficial Ownership Reporting Compliance

Under the federal securities laws, our General Partner, the General Partner's directors, executive (and certain other) officers, and any persons holding more than ten percent of our Common Units are required to report their ownership of Common Units and any changes in that ownership to us and the SEC. Specific due dates for these reports have been established by regulation, and we are required to disclose in this report any failure to file by these dates in 2002. We believe all of these filings were satisfied by our General Partner. We believe that during 2002 our reporting persons complied with all applicable filing requirements in a timely manner except: each of Dan L. Duncan and Enterprise Products Company filed three late Form 4 reports covering three transactions. Richard H. Bachmann filed one late Form 4 report covering one transaction. Each of Richard S. Snell, Lee S. Marshall and Dr. Ralph S. Cunningham filed one late Form 4 report covering one transaction.

In order to eliminate or reduce administrative and record keeping errors related to our Section 16(a) beneficial ownership reporting compliance, we have purchased new software to enable electronic filing of Forms 3, 4 and 5 and have instituted a new policy that prescribes procedures Section 16(a) officers must follow before engaging in transactions in our Units. The new procedures require a Section 16(a) officer to submit a notice of intent to engage in any reportable transaction to a Securities Transaction Committee composed of senior management officials of the General Partner and obtain the committee's clearance of the proposed transaction before it may take place.

ITEM 11. EXECUTIVE COMPENSATION.

We do not directly employ any of the persons responsible for managing or operating our businesses. Instead, our businesses are managed by the General Partner, the executive officers of which are employees of, and the compensation of whom is paid by, EPCO. We reimburse EPCO for our portion of the compensation EPCO pays individuals it employs as a result of our expansion-related activities (through business acquisitions, the construction of new facilities and the like). In addition, we pay EPCO an annual Administrative Services Fee (currently $17.6 million) to cover a portion of EPCO's total compensation costs for approximately 100 other individuals it employs for the management and operation of our businesses. For a more complete description of our relationship with EPCO, see Item 13 of this report.

That portion of the compensation of O.S. Andras, the General Partner's CEO, attributable to his services performed on our behalf is reimbursed to EPCO through our payment of the Administrative Services Fee. Of the EPCO employees serving our General Partner whose compensation is wholly or partially-reimbursed by us, the next four most highly compensated at December 31, 2002 were A.J. Teague, William D. Ray, Charles E. Crain and W. Ordemann. Collectively, these five individuals represent our "Named Executive Officers." The compensation of Mr. Ray and Mr. Crain is reimbursed to EPCO through our payment of the Administrative Services Fee. The compensation of Mr. Teague and Mr. Ordemann is wholly reimbursable by us apart from the Administrative Services Fee. The Named Executive Officers may have also received certain equity-based awards as part of their compensation from EPCO, the reimbursement of which by us is determined by whether or not their compensation is considered part of the Administrative Services Fee. As such, the cost of awards granted to Mr. Ray and Mr. Crain are the sole responsibility of EPCO; however, we are responsible for all of the costs associated with the awards granted to Mr. Teague and Mr. Ordemann. For additional information regarding our responsibilities under EPCO's equity-based award program, please see our footnote titled "Unit Option Plan Accounting" in the Notes to Financial Statements under Item 8 of this annual report.

The following table sets forth certain compensation information for our Named Executive Officers for the years ended December 31, 2002, 2001 and 2000. The Administrative Services Fee paid to EPCO for the years ended December 31, 2002, 2001 and 2000 was $16.6 million, $15.1 million and $13.8 million, respectively. Our payment of this annual fee is our maximum reimbursement to EPCO for the costs it incurs in managing and operating our business, apart from those expenses deemed attributable to our expansion and business development activities.

Summary Compensation Table

NAME AND PRINCIPAL POSITION	YEAR	ANNUAL COMPENSATION SALARY	BONUS	LONG-TERM COMPENSATION SECURITIES UNDERLYING OPTIONS (#)	ALL OTHER COMPENSATION (1)
O.S. Andras	2002(2)	$ 864,000	$ -	-	$ 13,671
Chief Executive Officer	2001(2)	$ 880,000	$ -	-	$ 10,078
	2000(2)	$ 880,000	$ -	-	$ 10,027
A. J. Teague,	2002	$ 370,000	$ 70,000	-	$ 17,240
Executive Vice President	2001	$ 345,000	$ 80,000	100,000	$ 11,160
	2000	$ 322,500	$ 35,000	100,000	$ 11,022
William D. Ray,	2002(2)	$ 225,000	$ 30,000	-	$ 17,089
Executive Vice President	2001(2)	$ 210,833	$ 40,000	20,000	$ 13,384
	2000(2)	$ 198,750	$ 25,000	-	$ 12,534
Charles E. Crain,	2002(2)	$ 240,000	$ 50,000	-	$ 17,089
Senior Vice President	2001(2)	$ 218,542	$ 60,000	20,000	$ 13,173
	2000(2)	$ 203,583	$ 25,000	-	$ 12,534
W. Ordemann,	2002	$ 209,000	$ 60,000	-	$ 14,398
Senior Vice President	2001(3)	$ 179,115	$160,000	40,000	$ 11,196
	2000	$ 156,094	$ 15,000	-	$ 10,428

(1) These amounts primarily represent contributions made by EPCO to the 401(k) plan of the Named Executive Officers.
(2) These amounts are included within Administrative Services Fee we pay to EPCO.
(3) Mr. Ordemann's 2001 bonuses include a $100,000 retention bonus agreed to when he joined us in connection with the TNGL acquisition in 1999.

Common Unit Option Grants during 2002. There were no individual grants of options to purchase Common Units granted to our Named Executive Officers during 2002.

Unit Options Exercised and Fiscal Year-End Values. The following table provides certain information concerning each exercise of options to purchase Common Units during the year ended December 31, 2002 by each of the Named Executive Officers and the value of unexercised options at December 31, 2002:

NAME	UNITS ACQUIRED ON EXERCISE (#)	VALUE REALIZED ($) (1)	NUMBER OF SECURITIES UNDERLYING UNEXERCISED OPTIONS AT DECEMBER 31, 2002		VALUE OF UNEXERCISED IN-THE-MONEY OPTIONS AT DECEMBER 31, 2002 (2)	
			EXERCISABLE	UNEXERCISABLE	EXERCISABLE	UNEXERCISABLE
O. S. Andras	-	$ -	-	-	$ -	$ -
A. J. Teague	-	$ -	-	200,000	$ -	$ 1,106,250
William D. Ray	-	$ -	20,000	20,000	$ 208,000	$ 69,500
Charlie E. Crain	-	$ -	40,000	20,000	$ 416,000	$ 69,500
W. Ordemann	-	$ -	20,000	40,000	$ 208,000	$ 139,000

(1) The "value realized" represents the difference between the exercise price of the Common Unit options and the market (sale) price of the Common Units on the date of exercise without considering any taxes which may have been owed by the beneficiary.
(2) The value is based on the $19.40 closing price of our Common Units at December 31, 2002.

Compensation of Directors. No additional compensation is paid to employees of EPCO or Shell who also serve as directors of the General Partner. The three independent outside directors are compensated for their services at the expense of the General Partner. During 2002, the three independent outside directors were paid collectively $85,500 by the General Partner for their service as directors.

The three independent outside directors have also been granted options to acquire our Common Units. During 2002, 40,000 of these Common Unit options were exercised by the independent directors at a cost of approximately $0.6 million to the General Partner. Collectively, these directors had 80,000 remaining Common Unit options outstanding at December 31, 2002.

Beginning in 2003, the compensation of our independent outside directors will increase. Specifically, each will receive (i) an annual retainer of $22,500, (ii) $1,250 for each meeting of the Board of Directors that they attend, (iii) $625 for each meeting of a committee of the Board of Directors that they attend and (iv) an annual retainer of $5,750 for those who serve as the chairman of a committee of the Board of Directors.

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

Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information as of March 1, 2003, regarding the beneficial ownership of our Common, Subordinated and Special Units by (i) all persons known by the General Partner to beneficially own more than five percent of the Common Units, (ii) the directors and certain executive officers of the General Partner and (iii) all directors, executive and other officers of the General Partner as a group.

	COMMON UNITS		SUBORDINATED UNITS		SPECIAL UNITS	
	NUMBER OF UNITS	PERCENT OF CLASS	NUMBER OF UNITS	PERCENT OF CLASS	NUMBER OF UNITS	PERCENT OF CLASS
Dan L. Duncan:						
Units owned by EPCO(1)	79,285,766	50.6%				
Units owned by Trusts(2)	2,478,236	1.6%				
Units owned directly	111,600	*				
Total for Dan L. Duncan	81,875,602	52.4%	32,114,804	100.0%		
Shell (3)	31,000,000	19.8%			10,000,000	100.0%
O.S. Andras (6)	2,941,200	1.9%				
Randa D. Williams (4)	1,000,000	*				
Lee W. Marshall, Sr.	13,340	*				
Richard S. Snell	1,200	*				
Richard H. Bachmann (5)	88,019	*				
A. J. Teague (6)	55,769	*				
William D. Ray (6,7)	40,108	*				
Charles E. Crain (6,8)	123,320	*				
W. Ordemann (6,9)	20,500	*				
All directors and executive officers as a group (21 persons)(10)	86,307,236	55.1%	32,114,804	100.0%		

* The beneficial ownership of each is less than 1% of our Common Units outstanding.

(1) EPCO owns its Units through a wholly-owned subsidiary, Enterprise Products Delaware Holdings, L.P. Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to the Units beneficially owned by EPCO. The remaining shares of EPCO capital stock are owned primarily by trusts for the benefit of the members of Mr. Duncan's family, including Randa D. Williams, a director of our General Partner. The address of EPCO and Mr. Duncan is 2727 North Loop West, Houston, Texas, 77008.

(2) In addition to the Units owned by EPCO, Dan L. Duncan has beneficial ownership of Common Units owned by the Duncan Family 1998 Trust and Duncan Family 2000 Trust.

(3) We issued Units to Shell US Gas & Power LLC (an affiliate of Shell) as part of the TNGL acquisition. The address of Shell US Gas & Power LLC is 1301 McKinney, Ste. 700, Houston, Texas 77010.

(4) Randa D. Williams is the trustee of four trusts set up for the benefit of the children of Dan L. Duncan. Ms. Williams is the daughter of Mr. Duncan. Of the 1,000,000 Common Units held by the four trusts, she has disclaimed beneficial ownership of 750,000 of these Units.

(5) Mr. Bachmann's beneficial ownership amount includes 80,000 Common Unit options issued under the equity compensation plan of EPCO that are exercisable within 60 days of the filing date of this report.

(6) These individuals are Named Executive Officers (see Item 11).

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

(8) Mr. Crain's beneficial ownership amount includes 40,000 Common Unit options issued under the equity compensation plan of EPCO that are exercisable within 60 days of the filing date of this report.

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

(10) Cumulatively, this group's beneficial ownership amount includes 260,000 Common Unit options issued under the equity compensation plan of EPCO that are exercisable within 60 days of the filing date of this report.

Subordinated Units and Special Units are non-voting until their conversion in Common Units. At present, we are not aware of any pledge of our securities or similar arrangement by owners our limited partnership interests, the operation of which at some future date may result in a change of control of our Company. For a discussion of our capital structure, see our footnote titled "Capital Structure" in the Notes to Consolidated Financial Statements under Item 8 of this annual report.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets for certain information as of December 31, 2002 regarding the equity compensation plan of our affiliate, EPCO, under which our Common Units are authorized for issuance to its key employees and to directors of the General Partner.

PLAN CATEGORY	NUMBER OF SECURITIES TO BE ISSUED UPON EXERCISE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	WEIGHTED-AVERAGE EXERCISE PRICE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	NUMBER OF SECURITIES REMAINING AVAILABLE FOR FUTURE ISSUANCE UNDER EQUITY COMPENSATION PLANS (EXCLUDING SECURITIES REFLECTED IN COLUMN (A))
	(A)	(B)	(C)
Equity compensation plans approved by Unitholders:			
None.	-	$ -	-
Equity compensation plans not approved by Unitholders:			
1998 Plan	2,310,078	$ 14.57	1,689,922
Total for equity compensation plans	2,310,078	$ 14.57	1,689,922

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

The 1998 Plan is governed by a committee formed by EPCO whose significant powers include, but are not limited to, (i) designating participants in the plan; (ii) determining the number of Common Units to be covered by the equity awards; (iii) determining the terms and conditions of any equity award; and (iv) determining, whether, to what extent, and under what circumstances participants may settle, exercise, cancel or forfeit any equity award. Subject to adjustment as provided in the 1998 Plan documents, the number of Common Units that may be awarded to participants is 4,000,000. The Common Units to be awarded under this plan may be obtained through purchases made on the open market or from affiliates of EPCO.

The exercise price of Common Unit options issued to participants is determined by the committee (at its discretion) at the date of grant and may be equal to, greater or less than its fair market value as of the date of grant. The committee determines the time or times at which the awards may be exercised in whole or in part, and the method or methods by which any payment of the exercise price with respect thereto may be made or deemed to have been made, which may include cash, notes receivable from the participant, or cashless-broker transactions or other acceptable forms of payment. In addition, to the extent provided by the committee, a Common Unit option grant may include a contingent right to receive an amount in cash equal to any cash distributions made by us with respect to the underlying Common Units during the period the award is outstanding. The 1998 Plan also provides for the issuance of restricted (or phantom) Common Units.

The 1998 Plan is effective until either all available Common Units under the plan have been paid to participants or the earlier termination of the Plan by EPCO. A second plan, the Enterprise Products 1999 Long-Term Incentive Plan, is inactive and has no options outstanding. At present, we have no intentions of issuing options under this second plan.

Commitments under equity compensation plans of EPCO

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

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

Equity-based awards granted to certain key expansion-related administrative and management employees. We also reimburse EPCO for the compensation of administrative and management 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 "expansion" group of EPCO employees. When these employees exercise Unit options, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the Units awarded to the employee. We may reimburse EPCO for these costs by either furnishing cash, reissuing Treasury Units or by issuing new Common Units.

Equity-based awards granted to other key administrative and management employees. In addition, we reimburse EPCO for our share of the costs of certain of its employees in administrative and management positions that were active at the time of our initial public offering in July 1998 who manage our business and affairs. Our reimbursement for the cost of equity-based awards to this "pre-expansion" group of employees is covered by the Administrative Services Fee we pay to EPCO. EPCO is responsible for the actual costs when the Unit awards granted to these pre-expansion employees are exercised. EPCO satisfies its equity-award obligations to these employees by arranging for Common Units to be purchased in the open market.

Our commitments at December 31, 2002

At December 31, 2002, there were 1,194,242 options outstanding to purchase Common Units under the 1998 Plan that had been granted to operations and expansion-related administrative and management employees for which we were responsible for reimbursing EPCO for the costs of such awards. The weighted-average strike price of the Unit option awards granted to this group was $15.73 per Common Unit. At December 31, 2002, 275,242 of these Unit options were exercisable. An additional 100,000, 570,000 and 249,000 of these Unit options will be exercisable in 2003, 2004 and 2005, respectively.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

Relationship with EPCO and its affiliates

We have an extensive and ongoing relationship with EPCO. EPCO is majority-owned and controlled by Dan L. Duncan, Chairman of the Board and a director of the General Partner. In addition, three other members of the Board of Directors (O.S. Andras, Randa D. Williams and Richard H. Bachmann) and the remaining executive and other officers (see Item 10 for a listing of these individuals) of the General Partner are employees of EPCO. 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 and Subordinated Units held by EPCO. The remaining shares of EPCO capital stock are held primarily by trusts for the benefit of the members of Mr. Duncan's family, including Ms. Williams (a director of the General Partner). In addition, EPCO and Dan Duncan, LLC collectively own 70% of the General Partner, which in turn owns a combined 2% interest in us.

In addition, trust affiliates of EPCO (the 1998 Trust and 2000 Trust) owned 2,478,236 Common Units at December 31, 2002. Collectively, EPCO, Dan L. Duncan, the 1998 Trust and the 2000 Trust owned 61.4% of our limited partnership interests at December 31, 2002.

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.

EPCO 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 EPCO Agreement. Under the terms of the EPCO Agreement, EPCO agrees to:

- employ the personnel necessary to manage our business and affairs (through the 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 of formulas 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 lease payments associated with these assets.

Operating costs and expenses (as shown in the Statements of Consolidated Operations) treat the lease payments being made by EPCO as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded a general contribution to the partnership. Should we decide to exercise the purchase options associated with the retained leases (which are at fair market value), up to $26.0 million will be payable in 2004, $3.4 million in 2008 and $3.1 million in 2016. In addition, operating costs and expenses include compensation charges for EPCO's employees who operate our facilities.

Pursuant to the EPCO Agreement, we reimburse 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 who manage our business and affairs. Our reimbursement of EPCO's administrative personnel expense is capped (currently at $17.6 million annually). The General Partner, with the approval and consent of the Audit and Conflicts Committee, may agree to increases of such fee up to ten percent per year during the 10-year term of the EPCO Agreement. Any difference between the actual costs of this "pre-expansion" group of administrative personnel (including costs associated with equity-based awards granted to certain individuals within this group) and the fee we pay will be born solely by EPCO. The actual amounts incurred by EPCO did not materially exceed the capped amounts for any periods. We also reimburse EPCO for the compensation of 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.

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.

- o EPCO is the operator of the facilities owned by BEF, of which we own 33.3%. In lieu of charging BEF for the actual cost of providing management services, EPCO charges BEF a management fee. EPCO charged BEF $0.6 million for such services during each of 2002, 2001 and 2000.

- o EPCO is also operator of the facilities owned by EPIK, of which we now wholly own. Prior to February 2003, we owned only 50% of EPIK. In lieu of charging EPIK for the actual cost of management services, EPCO charges EPIK a management fee. During 2002, 2001 and 2000, EPCO charged EPIK $0.3 million, $0.2 million and $0.3 million, respectively, for such services.

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

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

The following table summarizes our various related party transactions with EPCO for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
REVENUES FROM CONSOLIDATED OPERATIONS			
EPCO	$ 3,630	$ 5,439	$ 4,750
OPERATING COSTS AND EXPENSES			
EPCO	103,210	62,919	52,861
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES			
Base fees payable under EPCO Agreement	16,638	15,125	13,750
Other EPCO compensation reimbursement	7,566	4,824	1,930

Relationship with Shell

We have an extensive and ongoing commercial relationship with Shell as a partner, customer and vendor. Shell, through its subsidiary Shell US Gas & Power LLC, currently owns approximately 20.5% of our limited partnership interests and 30.0% of the General Partner. Currently, three members of the Board of Directors of the General Partner (J. A. Berget, J.R. Eagan, and A.Y. Noojin, III) are employees of Shell.

Shell is our single largest customer. During 2002, it accounted for 7.8% of our consolidated revenues. Our revenues from Shell reflect the sale of NGL and petrochemical products to them and the fees we charge them 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 (see below) and the purchase of NGL products from them. The following table shows our revenues and operating costs and expenses with Shell for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
REVENUES FROM CONSOLIDATED OPERATIONS			
Shell	$ 282,820	$ 333,333	$ 292,741
OPERATING COSTS AND EXPENSES			
Shell	531,712	705,440	736,655

The most significant contract affecting our natural gas processing business is the 20-year Shell processing agreement, which grants us the right to process Shell's current and future production from state and federal waters of the Gulf of Mexico on a keepwhole basis. This is a life of lease dedication, which may extend the agreement well beyond 20 years. Generally, this contract has the following rights and obligations:

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

- the exclusive right, but not the obligation, 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 plants from Shell's natural gas production from such leases; with

- the obligation to re-deliver to Shell the natural gas stream after the mixed NGL stream is extracted.

Under this contract, we are responsible for reimbursing Shell for the market value of the energy we extract from their natural gas stream in the course of performing natural gas processing services for them. Our reimbursement to Shell (which we record as an operating cost) is generally based upon the energy value of the fuel we consume and the NGLs we extract from their natural gas stream (in terms of its Btu content, a measure of heating value). In lieu of collecting a cash fee for our services under this contract, we take ownership of the NGLs we extract from their natural gas stream. These volumes (our "equity NGL production") become part of our inventory held for sale. We derive a profit to the extent that the revenues from the ultimate sale and delivery of these NGLs to customers exceeds the costs of extraction and any other ancillary costs such as fractionation fees.

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 $529 million (this purchase price includes both the $166 million in cash we paid to Shell and the value of the three issues of Special Units granted to Shell in connection with this acquisition);

- the purchase of the Lou-Tex Propylene Pipeline System for $100 million in 2000; and,

- the acquisition of Acadian Gas in 2001 for $244 million.

Shell is also a partner with us in the Gulf of Mexico natural gas pipelines we acquired from El Paso in 2001. 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 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 $2.2 million in letters of credit on behalf of Evangeline.

- We pay EPIK for export services to load product cargoes for our NGL and petrochemical marketing customers.

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

- We sell high purity isobutane to BEF as a feedstock and purchase certain of BEF's by-products. We also receive transportation fees for MTBE movements on our HSC pipeline and fractionation revenues for reprocessing mixed feedstock streams generated by BEF.

- 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.

The following table summarizes our related party transactions with unconsolidated affiliates for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
REVENUES FROM CONSOLIDATED OPERATIONS			
Evangeline	$ 131,635	$ 117,283	$
EPIK	259	297	5,070
BEF	50,494	45,778	56,216
Promix	12,697	8,952	57
Other unconsolidated affiliates	1,182	1,374	645
OPERATING COSTS AND EXPENSES			
EPIK	19,788	7,438	17,600
Dixie	12,184	12,695	11,763
BEF	9,794	8,073	10,640
Promix	18,408	12,676	18,200
Other unconsolidated affiliates	428	181	

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.

ITEM 14. CONTROLS AND PROCEDURES.

In the 90-day period before the filing of this report, the CEO and CFO of the General Partner of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. (collectively the "registrants") have evaluated the effectiveness of the registrants' disclosure controls and procedures. These disclosure controls and procedures are those controls and other procedures we maintain, which are designed to insure that all of the information required to be disclosed by the registrants in all of their combined and separate periodic reports filed with the SEC is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the registrants in their reports filed or submitted under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including the CEO and CFO of the General Partner, as appropriate to allow those persons to make timely decisions regarding required disclosure.

Subsequent to the date when the disclosure controls and procedures were evaluated, there have not been any significant changes in the registrants' controls or procedures or in other factors that could significantly affect such controls or procedures. No significant deficiencies or material weaknesses were detected, so no corrective actions needed to be taken.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

(a)(1) and (2) Financial Statements and Financial Statement Schedules.

See "Index to Financial Statements" set forth on page F-1.

(a)(3) Exhibits.

EXHIBIT NO.		EXHIBIT*
2.1	--	Purchase and Sale Agreement between Coral Energy, LLC and Enterprise Products Operating L.P. dated September 22, 2000 (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 26, 2000).
2.2	--	Purchase and Sale Agreement dated January 16, 2002 by and between Diamond-Koch, L.P. and Diamond-Koch III, L.P. and Enterprise Products Texas Operating L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 8, 2002.)
2.3	--	Purchase and Sale Agreement dated January 31, 2002 by and between D-K Diamond-Koch, L.L.C., Diamond-Koch, L.P. and Diamond-Koch III, L.P. as Sellers and Enterprise Products Operating L.P. as Buyer (incorporated by reference to Exhibit 10.2 to Form 8-K filed February 8, 2002).
2.4	--	Purchase Agreement by and between E-Birchtree, LLC and Enterprise Products Operating L.P. dated July 31, 2002 (incorporated by reference to Exhibit 2.2 to Form 8-K filed August 12, 2002).
2.5	--	Purchase Agreement by and between E-Birchtree, LLC and E-Cypress, LLC dated July 31, 2002 (incorporated by reference to Exhibit 2.1 to Form 8-K filed August 12, 2002).
3.1	--	First Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC dated as of September 17, 1999 (incorporated by reference to Exhibit 99.8 to the Form 8-K/A-l filed October 27, 1999).
3.2**	--	Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of the General Partner dated as of September 19, 2002.
3.3	--	Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated May 15, 2002 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 13, 2002).
3.4	--	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated August 7, 2002 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 13, 2002).
3.5	--	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated December 17, 2002 (incorporated by reference to Exhibit 3.5 to Form 8-K filed December 17, 2002).
3.6	--	Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. dated as of July 31, 1998 (incorporated by reference to Exhibit 3.2 to Registration Statement on Form S-1/A filed July 21, 1998).
4.1	--	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.2	--	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4 filed January 28, 2003).
4.3**	--	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee.
4.4	--	Global Note representing $350 million principal amount of 6.375% Series A Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4 filed January 28, 2003).
4.5**	--	Rule 144 A Global Note representing $499.2 million principal amount of 6.875% Series A Senior Notes due 2033 with attached Guarantee.

4.6**	--	Regulation S Global Note representing $800,000 principal amount of 6.875% Series A Senior Notes due 2033 with attached Guarantee.
4.7	--	Form of Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (included in Exhibit 4.2).
4.8**	--	Form of Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (included in Exhibit 4.3).
4.9	--	Registration Rights Agreement dated as of January 22, 2003, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.5 to Registration Statement on Form S-4 filed January 28, 2003).
4.10**	--	Registration Rights Agreement dated as of February 14, 2003, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein.
4.11	--	Global Note representing $350 million principal amount of 8.25% Senior Notes due 2005 (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 10, 2000).
4.12	--	Global Note representing $450 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.13	--	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.14	--	$250 Million Multi-Year Revolving Credit Facility dated as of November 17, 2000, among Enterprise Products Operating L.P., First Union National Bank, as Administrative Agent, Bank One, NA, as Documentation Agent, the Chase Manhattan Bank, as Syndication Agent, and the several banks from time to time parties thereto, with First Union Securities, Inc. and Chase Securities Inc. as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 4.2 to Form 8-K filed January 24, 2001).
4.15	--	$150 Million 364-Day Revolving Credit Facility November 17, 2000, among Enterprise Products Operating L.P., First Union National Bank, as Administrative Agent, Bank One, NA, as Documentation Agent, the Chase Manhattan Bank, as Syndication Agent, and the several banks from time to time parties thereto, with First Union Securities, Inc. and Chase Securities Inc. as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 24, 2001).
4.16	--	Guaranty Agreement dated as of November 17, 2000, by Enterprise Products Partners L.P. in favor of First Union National Bank, as Administrative Agent, with respect to the $250 Million Multi-Year Revolving Credit Facility included as Exhibit 4.4 above (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 24, 2001).
4.17	--	Guaranty Agreement dated as of November 17, 2000, by Enterprise Products Partners L.P. in favor of First Union National Bank, as Administrative Agent, with respect to the $150 Million 364-Day Revolving Credit Facility (incorporated by reference to Exhibit 4.5 to Form 8-K filed January 24, 2001).
4.18	--	First Amendment to Multi-Year Credit Facility dated April 19, 2001 (incorporated by reference to Exhibit 4.12 to Form 10-Q filed May 14, 2001).
4.19	--	Second Amendment to Multi-Year Revolving Credit Facility dated April 14, 2002 (incorporated by reference to Exhibit 4.14 to Form 10-Q filed May 14, 2002).
4.20	--	Third Amendment to Multi-Year Revolving Credit Facility dated July 31, 2002 (incorporated by reference to Exhibit 4.1 to Form 10-Q filed August 12, 2002).
4.21	--	Fourth Amendment to Multi-Year Revolving Credit Facility dated effective as of November 15, 2002 (incorporated by reference to Exhibit 4.21 to Form 10-Q filed November 13, 2002).
4.22	--	First Amendment to 364-Day Credit Facility dated November 6, 2001, effective as of November 16, 2001 (incorporated by reference to Exhibit 4.13 to Form 10-Q filed August 13, 2002).
4.23	--	Second Amendment to 364-Day Revolving Credit Facility dated April 24, 2002 (incorporated by reference to Exhibit 4.15 to Form 10-Q filed May 14, 2002).
4.24	--	Third Amendment to 364-Day Revolving Credit Facility dated July 31, 2002 (incorporated by reference to Exhibit 4.2 to Form 8-K filed August 12, 2002).
4.25	--	Contribution Agreement dated September 17, 1999 (incorporated by reference to Exhibit "B" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.26	--	Registration Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "E" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.27	--	Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "C" to

		Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
10.1	--	$1.2 Billion 364-Day Term Credit Facility dated as of July 31, 2002, among Enterprise Products Operating Partnership L.P., Wachovia Bank, National Association, as Administrative Agent, Lehman Commercial Paper Inc., as Co-Syndication Agent, Royal Bank of Canada, as Co- Syndication Agent and Arranger, with Wachovia Securities, Inc. and Lehman Brothers Inc., as Lead Arrangers and Joint Bookrunners and RBC Capital Markets, as Arranger (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 12, 2002).
10.2	--	Guaranty Agreement dated as of July 31, 2002 by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent, with respect to the $1.2 Billion 364-Day Term Credit Facility (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 12, 2002).
10.3	--	EPCO Agreement among Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products Company dated July 31, 1998 (incorporated by reference to Exhibit 10.3 to Registration Statement on Form S-4 filed January 28, 2003).
10.4	--	Transportation Contract between Enterprise Products Operating L.P. and Enterprise Transportation Company dated June 1, 1998 (incorporated by reference to Exhibit 10.3 to Registration Statement Form S-1/A filed July 8,1998).
10.5	--	Partnership Agreement among Sun BEF, Inc., Liquid Energy Fuels Corporation and Enterprise Products Company dated May 1, 1992 (incorporated by reference to Exhibit 10.5 to Registration Statement on Form S-1 filed May 13, 1998).
10.6	--	Propylene Facility and Pipeline Agreement between Enterprise Petrochemical Company and Hercules Incorporated dated December 13, 1978 (incorporated by reference to Exhibit 10.9 to Registration Statement on Form S-l filed May 13, 1998).
10.7	--	Restated Operating Agreement for the Mont Belvieu Fractionation Facilities Chambers County, Texas among Enterprise Products Company, Texaco Producing Inc., El Paso Hydrocarbons Company and Champlin Petroleum Company dated July 17, 1985 (incorporated by reference to Exhibit 10.10 to Registration Statement on Form S-l/A filed July 8,1998).
10.8	--	Amendment to Propylene Facility and Pipeline Agreement and Propylene Sales Agreement between HIMONT U.S.A., Inc. and Enterprise Products Company dated January 1, 1993 (incorporated by reference to Exhibit 10.12 to Registration Statement on Form S-l/A filed July 8, 1998).
10.9	--	Amendment to Propylene Facility and Pipeline Agreement and Propylene Sales Agreement between HIMONT U.S.A., Inc. and Enterprise Products Company dated January 1, 1995 (incorporated by reference to Exhibit 10.13 to Registration Statement on Form S-l/A filed July 8, 1998).
10.10	--	Fourth Amendment to Conveyance of Gas Processing Rights among Tejas Natural Gas Liquids, LLC and Shell Oil Company, Shell Exploration & Production Company, Shell Offshore Inc., Shell Deepwater Development Inc., Shell Land & Energy Company and Shell Frontier Oil & Gas Inc. dated August 1, 1999 (incorporated by reference to Exhibit 10.14 to Form 10-Q filed November 15, 1999).
10.11	--	Fifth Amendment to Conveyance of Gas Processing Rights dated as of April 1, 2001 among Enterprise Gas Processing, LLC, Shell Oil Company, Shell Exploration & Production Company, Shell Offshore Inc., Shell Consolidated Energy Resources, Inc., Shell Land & Energy Company and Shell Frontier Oil & Gas, Inc. (incorporated by reference to Exhibit 10.13 to Form 10-Q filed August 13, 2001).
10.12***	--	Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.1 to Post-Effective Amendment No. 1 to Registration Statement on Form S-8 filed March 13, 2003).
10.13***	--	Form of Option Grant Award under the 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.2 to Post-Effective Amendment No. 1 to Registration Statement on Form S-8 filed March 13, 2003).
12.1**	--	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2002, 2001, 2000, 1999 and 1998 for Enterprise Products Partners L.P.
12.2**	--	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2002, 2001, 2000, 1999 and 1998 for Enterprise Products Operating L.P.
21.1**	--	List of Subsidiaries of the Registrants.
23.1#	--	Consent of Deloitte & Touche LLP.

99.1**	--	Audited Balance Sheet of Enterprise Products GP, LLC, as of December 31, 2002.
99.2#	--	Section 1350 Certifications

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P. is 1-14323 and the Commission file number for Enterprise Products Operating L.P. is 333-93239-01.

** Previously filed with our original Form 10-K on March 31, 2003.

*** Identifies management contract and compensatory plan arrangements

\# Filed with this report.

(b) Reports on Form 8-K.

October 2, 2002 filing: (Items 5 and 7) We filed the General Partner's audited balance sheet as of December 31, 2001 and unaudited balance sheet as of June 30, 2002.

October 3, 2002 filing: (Items 5 and 7) On October 2, 2002, we entered into an underwriting agreement for a public offering of 9,800,000 Common Units. This included 1,809,200 common units to be offered to members of our senior management and affiliates. The underwriters were granted an option to purchase up to 1,470,000 additional partnership units to cover over-allotments.

December 11, 2002 filing: (Items 5 and 7) On December 11, 2002, we filed the General Partner's September 30, 2002 unaudited balance sheet.

December 17, 2002 filing: (Items 5, 7 and 9) On December 17, 2002, we announced that our partnership agreement was amended to eliminate the General Partner's incentive distribution right to receive 50% of total cash distributions with respect to that portion of quarterly cash distributions that exceed $0.392 per unit.

December 31, 2002 filing: (Item 7) On December 31, 2002, we filed certain pro forma consolidated financial statements and accompanying notes. The pro forma financial statements included in this Form 8-K reflected strategic acquisitions completed since January 2001 and the Common Unit offering we completed in October 2002.

INDEX TO FINANCIAL STATEMENTS

All schedules, except those listed above, have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of Enterprise Products GP, LLC
(the General Partner of Enterprise Products 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, 2002 and 2001, 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, 2002. Our audits also included the consolidated financial statement schedule of the Company listed in the Index to the Financial Statements. 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 auditing standards generally accepted in the United States of America. 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, 2002 and 2001, and the results of its consolidated operations and its consolidated cash flows for each of the three years in the period ended December 31, 2002 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 7, 2003

ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(DOLLARS IN THOUSANDS)

	DECEMBER 31,	
ASSETS	2002	2001
CURRENT ASSETS		
Cash and cash equivalents (includes restricted cash of $8,751 at December 31, 2002 and $5,752 at December 31, 2001)	$ 22,568	$ 137,823
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $21,196 at December 31, 2002 and $20,642 at December 31, 2001	399,187	256,024
Accounts receivable - affiliates	228	4,375
Inventories	167,369	62,942
Prepaid and other current assets	48,216	51,110
Total current assets	637,568	512,274
PROPERTY, PLANT AND EQUIPMENT, NET	2,810,839	1,306,790
INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES	396,993	398,201
INTANGIBLE ASSETS, NET OF ACCUMULATED AMORTIZATION OF $25,546 AT DECEMBER 31, 2002 AND $13,084 AT DECEMBER 31, 2001	277,661	202,226
GOODWILL	81,547	
DEFERRED TAX ASSET	15,846	
OTHER ASSETS	9,818	5,201
TOTAL	$ 4,230,272	$ 2,424,692
LIABILITIES AND PARTNERS' EQUITY		
CURRENT LIABILITIES		
Current maturities of long-term debt	$ 15,000	
Accounts payable - trade	$ 67,283	$ 54,269
Accounts payable - affiliates	40,772	29,885
Accrued gas payables	489,562	227,035
Accrued expenses	35,760	22,460
Accrued interest	30,338	24,302
Other current liabilities	42,641	44,764
Total current liabilities	721,356	402,715
LONG-TERM DEBT	2,231,463	855,278
OTHER LONG-TERM LIABILITIES	7,666	8,061
MINORITY INTEREST	68,883	11,716
COMMITMENTS AND CONTINGENCIES		
PARTNERS' EQUITY		
Common Units (141,694,766 Units outstanding at December 31, 2002 and 102,721,830 at December 31, 2001)	949,835	651,872
Subordinated Units (32,114,804 Units outstanding at December 31, 2002 and 42,819,740 at December 31, 2001)	116,288	193,107
Special Units (10,000,000 Units outstanding at December 31, 2002 and 29,000,000 December 31, 2001)	143,926	296,634
Treasury Units acquired by Trust, at cost (859,200 Common Units outstanding at December 31, 2002 and 327,200 at December 31, 2001)	(17,808)	(6,222)
General Partner	12,223	11,531
Accumulated Other Comprehensive Loss	(3,560)	
Total Partners' Equity	1,200,904	1,146,922
TOTAL	$ 4,230,272	$ 2,424,692

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,		
	2002	2001	2000
REVENUES			
Revenues from consolidated operations			
Third parties	$ 3,102,066	$ 2,641,913	$ 2,689,541
Related parties	482,717	512,456	359,479
Total revenues	3,584,783	3,154,369	3,049,020
COST AND EXPENSES			
Operating costs and expenses			
Third parties	2,686,982	2,052,309	1,953,341
Related parties	695,579	809,434	847,719
Selling, general and administrative			
Third parties	18,686	10,347	12,665
Related parties	24,204	19,949	15,680
Total costs and expenses	3,425,451	2,892,039	2,829,405
EQUITY IN INCOME OF UNCONSOLIDATED AFFILIATES	35,253	25,358	24,119
OPERATING INCOME	194,585	287,688	243,734
OTHER INCOME (EXPENSE)			
Interest expense	(101,580)	(52,456)	(33,329)
Interest income from related parties	139	31	1,787
Dividend income from unconsolidated affiliates	4,737	3,462	7,091
Interest income - other	2,313	7,029	3,748
Other, net	(113)	(1,104)	(272)
Other income (expense)	(94,504)	(43,038)	(20,975)
INCOME BEFORE PROVISION FOR INCOME TAXES AND MINORITY INTEREST	100,081	244,650	222,759
PROVISION FOR INCOME TAXES	(1,634)		
INCOME BEFORE MINORITY INTEREST	98,447	244,650	222,759
MINORITY INTEREST	(2,947)	(2,472)	(2,253)
NET INCOME	95,500	242,178	220,506
Cumulative transition adjustment related to financial instruments recorded upon adoption of SFAS No. 133 (see Note 1)		(42,190)	
Reclassification of cumulative transition adjustment to earnings		42,190	
Change in fair value of financial instruments recorded as cash flow hedges	(3,560)		
COMPREHENSIVE INCOME	$ 91,940	$ 242,178	$ 220,506
ALLOCATION OF NET INCOME TO:			
Limited partners	$ 84,837	$ 236,570	$ 217,909
General partner	$ 10,663	$ 5,608	$ 2,597
BASIC EARNINGS PER UNIT			
Income before minority interest	$ 0.56	$ 1.71	$ 1.64
Net income per Common and Subordinated unit	$ 0.55	$ 1.70	$ 1.62
DILUTED EARNINGS PER UNIT			
Income before minority interest	$ 0.50	$ 1.40	$ 1.34
Net income per Common, Subordinated and Special unit	$ 0.48	$ 1.39	$ 1.32

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(DOLLARS IN THOUSANDS)

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
OPERATING ACTIVITIES			
Net income	$ 95,500	$ 242,178	$ 220,506
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:			
Depreciation and amortization in operating costs and expenses	86,029	48,775	35,621
Depreciation in selling, general and administrative costs	77	2,341	1,689
Amortization in interest expense	8,819	787	3,735
Equity in income of unconsolidated affiliates	(35,253)	(25,358)	(24,119)
Distributions received from unconsolidated affiliates	57,662	45,054	37,267
Leases paid by EPCO	9,033	10,309	10,537
Minority interest	2,947	2,472	2,253
Loss (gain) on sale of assets	(1)	(390)	2,270
Deferred income tax expense	2,080		
Changes in fair market value of financial instruments (see Note 18)	10,213	(5,697)	
Net effect of changes in operating accounts	92,655	(37,143)	71,111
Operating activities cash flows	329,761	283,328	360,870
INVESTING ACTIVITIES			
Capital expenditures	(72,135)	(149,896)	(243,913)
Proceeds from sale of assets	165	568	92
Business acquisitions, net of cash received	(1,620,727)	(225,665)	
Acquisition of intangible asset	(2,000)		
Collection of note receivable from unconsolidated affiliate			6,519
Investments in and advances to unconsolidated affiliates	(13,651)	(116,220)	(31,496)
Investing activities cash flows	(1,708,348)	(491,213)	(268,798)
FINANCING ACTIVITIES			
Borrowings under debt agreements	1,968,000	449,717	598,818
Repayments of debt	(637,000)		(490,000)
Debt issuance costs	(19,329)	(3,125)	(4,043)
Distributions paid to partners	(214,869)	(164,308)	(139,577)
Distributions paid to minority interest by Operating Partnership	(3,324)	(1,687)	(1,429)
Contributions from minority interest	1,976	105	108
Common Units repurchased and retired			(770)
Proceeds from issuance of Common Units	180,666		
Treasury Units purchased	(12,788)	(18,003)	
Treasury Units reissued		22,600	
Increase in restricted cash	(2,999)	(5,752)	
Financing activities cash flows	1,260,333	279,547	(36,893)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(118,254)	71,662	55,179
CASH AND CASH EQUIVALENTS, JANUARY 1	132,071	60,409	5,230
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 13,817	$ 132,071	$ 60,409

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	SPECIAL UNITS	TREASURY UNITS	GENERAL PARTNER	ACCUM. OCI	TOTAL
Balance, December 31, 1999	$ 439,196	$ 136,618	$ 210,436	$ (4,727)	$ 7,942		$ 789,465
Net income	148,656	69,253			2,597		220,506
Leases paid by EPCO	7,117	3,315			105		10,537
Special Units issued to Shell under contingency agreement			55,241		557		55,798
Conversion of 2.0 million Shell Special Units to Common Units	14,513		(14,513)				-
Common Units repurchased and retired	(687)	(43)	(32)		(8)		(770)
Cash distributions to partners	(93,899)	(43,890)			(1,788)		(139,577)
Balance, December 31, 2000	514,896	165,253	251,132	(4,727)	9,405		935,959
Net income	163,795	72,775			5,608		242,178
Leases paid by EPCO	7,078	3,128			103		10,309
Special Units issued to Shell under contingency agreement			117,066		1,183		118,249
Conversion of 10.0 million Shell Special Units to Common Units	72,554		(72,554)				
Cash distributions to partners	(109,969)	(49,510)			(4,829)		(164,308)
Treasury Units purchased				(18,003)			(18,003)
Treasury Units reissued				16,508			16,508
Gain on reissuance of Treasury Units by consolidated Trust	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
Leases paid by EPCO	6,872	2,071			90		9,033
Conversion of 19.0 million Shell Special Units to Common Units	152,708		(152,708)				-
Conversion of 10.7 million EPCO Subord. Units to Common Units	44,265	(44,265)					-
Cash distributions to partners	(153,449)	(49,564)			(11,856)		(214,869)
Proceeds from issuance of Common Units in October 2002	178,859				1,807		180,666
Treasury Units purchased				(12,788)			(12,788)
Treasury Units reissued to satisfy EPCO Unit option plans	(928)	(262)		1,202	(12)		-
Change in fair value of financial instruments recorded as cash flow hedges (see Note 18)						(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

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 New York Stock Exchange under symbol "EPD". Unless the context requires otherwise, references to "we","us","our" or the "Company" within these notes are intended to mean Enterprise Products Partners L.P. and subsidiaries. We (including our operating subsidiary, Enterprise Products Operating L.P. (the "Operating Partnership")) were formed in April 1998 to own and operate the natural gas liquids ("NGL") business of Enterprise Products Company ("EPCO"). We conduct substantially all of our business through the Operating Partnership, in which we own a 98.9899% limited partner interest. Enterprise Products GP, LLC (the "General Partner") owns 1.0101% of the Operating Partnership and 1% of the Company and serves as the general partner of both entities. We and the General Partner are affiliates of EPCO.

Prior to their consolidation, EPCO and its affiliate companies were controlled by members of a single family, who collectively owned at least 90% of each of the entities for all periods prior to the formation of the Company. As of April 30, 1998, the owners of all the affiliated companies exchanged their ownership interests for shares of EPCO. Accordingly, each of the affiliated companies became a wholly-owned subsidiary of EPCO or was merged into EPCO as of April 30, 1998. In accordance with generally accepted accounting principles, the consolidation of the affiliated companies with EPCO was accounted for as a reorganization of entities under common control in a manner similar to a pooling of interests.

Under terms of a contract entered into on May 8, 1998 between EPCO and our Operating Partnership, EPCO contributed all of its NGL assets through the Company and the General Partner to the Operating Partnership and the Operating Partnership assumed certain of EPCO's debt. As a result, we became the successor to the NGL operations of EPCO. Effective July 27, 1998, we filed a registration statement pursuant to an initial public offering of 24,000,000 Common Units at $11 per unit. We received approximately $243.3 million net of underwriting commissions and offering costs.

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 the Company 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 other than a temporary decline. The Company considers events affecting its equity method investments such as if they had continuing operating losses or significant and long-term changes in their industry conditions as examples of indicators of potential impairment. 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 for 2002, 2001 and 2000.

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 results of consolidated operations.

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.

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. Specifically, basic earnings per Unit is calculated by dividing the amount of income allocated to limited partners by the weighted-average number of Common and Subordinated Units outstanding during the period. Diluted earnings per Unit is based on the amount of income allocated to limited partners and the weighted-average number of Common, Subordinated and Special Units outstanding during the period. The Special Units are excluded from the computation of basic earnings per Unit because, under the terms of the Special Units, they do not share in income nor are they entitled to cash distributions until they are converted to Common Units. Treasury Units are not considered to be outstanding; therefore, they are excluded from the computation of both basic and diluted earnings per Unit. 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, 2002 were not significant to the consolidated financial statements. Costs of environmental compliance and monitoring aggregated $1.7 million, $1.3 million and $1.3 million for the years ended December 31, 2002, 2001 and 2000, 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 investments in Promix, Dixie, Neptune, La Porte and Nemo. The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. 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.

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 the Company. 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. 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 (as amended and interpreted) 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.

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. We have not recognized any impairment losses for any of the periods presented.

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 adopted SFAS No. 144 on January 1, 2002, and there have been no events or circumstances indicating that the carrying value of any of our assets may not be recoverable.

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 the Company. We generally classify improvements and major renewals of existing assets as sustaining capital expenditures and all other capital spending (on existing and new assets) as expansion capital expenditures.

PROVISION FOR INCOME TAXES is only applicable to the tax obligation of our Seminole pipeline business, which is a corporation and the only entity subject to income taxes in the consolidated group. The income tax provision relates solely to Seminole's earnings before income taxes for the five month period ended December 31, 2002. Deferred income tax assets and liabilities for Seminole are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes (see Note 12).

In and of itself, 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, 2002 and 2001, cash and cash equivalents includes $8.8 million and $5.8 million of restricted cash related to these requirements, respectively.

REVENUE is recognized by our five reportable business segments 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. For additional information regarding our revenue recognition process, please see Note 2.

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 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 $21.2 million and $20.6 million at December 31, 2002 and 2001, respectively.

UNIT OPTION PLAN ACCOUNTING for reimbursement to EPCO under its 1998 Plan is accounted for by applying APB Opinion No. 25, "Accounting for Stock Issued to Employees," in accounting for equity-based awards granted to EPCO's employees whereby no compensation expense is recorded related to the options granted when the exercise price equals the market price of the underlying equity issue on the date of grant. See Note 15 for the pro forma effect on our net income and earnings per unit, as if compensation expense had been determined based on the Black-Scholes option pricing model value at the grant date for Unit option awards consistent with the provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." No compensation expense was recorded during the years ended December 31, 2002, 2001 and 2000, since the options were granted at exercise prices equal to the market prices at the date of grant.

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. REVENUE RECOGNITION

The following summarizes our revenue recognition process by business segment:

Pipelines segment revenues. In our Pipelines segment, 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 Federal Energy Regulatory Commission ("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.

Fractionation segment revenues. In our Fractionation segment, we enter into NGL fractionation, isomerization and propylene fractionation tolling arrangements, NGL fractionation in-kind 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, an in-kind tolling arrangement is utilized. An in-kind 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. Fractionation revenue is recognized and recorded on a monthly basis for transfers of "in-kind" retained NGL products to the NGL working inventory maintained within our Processing 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 Processing 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.

Processing segment revenues. As part of our Processing business, we have entered into a significant 20-year natural gas processing agreement with Shell (the "Shell Processing Agreement"), whereby we have the right to process Shell's current and future natural gas production (including deepwater developments) from the Gulf of Mexico within the state and federal waters off Texas, Louisiana, Mississippi, Alabama and Florida. In addition to the Shell Processing Agreement, we have contracts to process natural gas for other customers.

Under these natural gas processing contracts, the fee for our natural gas processing services is based upon contractual terms with Shell or other third parties and may be specified as either a cash fee or the retention of a percentage of the NGLs extracted from the natural gas stream. 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 Shell or other third parties (i.e., delivery has taken place).

If the natural gas processing contract stipulates that we retain a percentage of the extracted NGLs as payment for our services, revenue is recognized and recorded when the extracted NGLs are delivered out of our inventory and sold to customers on sales contracts. Our NGL marketing activities within this segment also use product sales contracts to sell and deliver out of inventory the NGLs transferred to it as a result of the Fractionation segment's in-kind 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 differing delivery locations.

Octane Enhancement segment revenues. The Octane Enhancement segment consists of our equity 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. Gross operating margin for this segment consists of our equity earnings from BEF, which in turn is dependent upon is BEF's general revenue recognition policy. 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.

Other segment revenues. Revenues shown for our Other segment are primarily derived from fee-based marketing services. 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.

Use of estimates in our revenue recognition process. The revenues that we record are not materially based on estimates. We believe the assumptions underlying any revenue estimates that we might use will not prove to be significantly different from actual amounts due to the routine nature of these estimates.

3. RECENTLY ISSUED ACCOUNTING STANDARDS

We adopted SFAS No. 142, "Goodwill and Other Intangible Assets", on January 1, 2002. This standard establishes accounting standards for all goodwill and other intangible assets recognized in our consolidated balance sheet. In addition, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" on January 1, 2002. This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. For information regarding our goodwill and intangible assets see Note 8. For information regarding our accounting policy for long-lived assets, please see Note 1.

We adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," on January 1, 2003. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation ("ARO") and the associated asset retirement cost. An ARO exists when a company determines that it has a clearly defined legal obligation upon retirement of a long-lived asset or any component part thereof and that the legal obligation will lead to the future payment of funds to a third party upon retirement of the asset. In general, legal obligations underlying AROs result from enacted laws and regulations or from contractual provisions related to long-lived assets. AROs can also arise through the normal course of operating a long-lived fixed asset.

An ARO liability will be recorded on the balance sheet if a reasonable estimate of fair value of the obligation can be made. Our estimate of fair value for each ARO is primarily dependent upon a clearly defined plan of retirement (dates, methods, etc.) and costs associated with the retirement activity. If a reasonable estimate cannot be made (i.e., no current or required plans for retirement of the asset, etc.), footnote disclosure is required but the ARO is not recorded until a reasonable estimate can be made. Any earnings impact resulting from the recognition of an ARO upon adoption of SFAS No. 143 should be reflected as the cumulative effect of a change in accounting principle.

Upon adoption of SFAS No. 143, we reviewed our long-lived assets for ARO's by segment. We identified, but have not recognized, ARO liabilities in several operational areas. These include ARO liabilities related to easements over property not currently owned by us. Our rights to the easements are renewable and only require retirement action upon nonrenewal of the easement agreements. We currently plan to renew all such easement agreements and use these properties indefinitely. Therefore, the ARO liability is not estimable for such easements. If we decide not to renew these agreements, an ARO liability would be recorded at that time.

ARO liabilities related to statutory regulatory requirements for abandonment or retirement of certain currently operated facilities were also identified. 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 occurred.

Certain Gulf of Mexico natural gas pipelines, in which we have an equity interest, have identified ARO's relating to regulatory requirements. There is no current intention to abandon or retire these pipelines. If these pipelines were abandoned or retired, an ARO liability would then be disclosed.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." This standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operations, plant closing, or other exit or disposal activity. Previous accounting guidance was provided by EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 replaces Issue 94-3. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002. We adopted this statement on January 1, 2003 and determined that it had no material impact on our financial statements.

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements from Guarantees, Including Indirect Guarantees of Indebtedness of Others". 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. The initial recognition and measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements in this interpretation are applicable for financial statements of interim or annual periods after December 15, 2002. See Note 9 for the disclosure of Parent-Subsidiary guarantor relationships.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure," which 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 in both annual and interim financial statements. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002, and financial reports containing condensed financial statements for interim periods beginning after December 15, 2002. EPCO has stock-based employee compensation plans for which we have a funding commitment for certain employees, see Note 15. We do not believe that the adoption of this statement will have a material effect on our financial statements.

4. BUSINESS ACQUISITIONS

ACQUISITION OF MID-AMERICA AND SEMINOLE IN JULY 2002

On July 31, 2002, we acquired equity interests in affiliates of Williams, which in turn, own controlling interests in Mid-America Pipeline Company, LLC ("Mid-America," formerly Mid-America Pipeline Company) and Seminole Pipeline Company ("Seminole"). The purchase price of the acquisitions was approximately $1.2 billion. The acquisition of Mid-America and Seminole significantly enhances our existing asset base by:

- accessing NGL-rich natural gas production in major North American natural gas producing regions;
- expanding our integrated natural gas and NGL network;
- providing access to new end markets for NGL products; and
- increasing our gross margins from fee-based businesses.

In addition to our current strategic position in the Gulf of Mexico, we now have access to major supply basins throughout North America, including the Rocky Mountain Overthrust, the San Juan and Permian basins, the Mid-Continent region and, through third-party pipeline connections, north into Canada's Western Sedimentary basin. The combination of these assets with our existing assets also creates a significant link between Mont Belvieu, Texas and Conway, Kansas, the two largest NGL hubs in the United States. They also provide additional access to new end markets for NGL products.

The acquisitions include a 98% ownership interest in Mapletree, LLC, which is the sole owner of Mid-America and certain propane terminals and storage facilities. Mid-America owns a regulated 7,226-mile major NGL pipeline system (the "Mid-America 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 Rocky Mountain system 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, through third-party pipeline connections, NGL supplies from Canada's Western Sedimentary basin.

The Conway South system 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 acquired a 98% ownership interest in E-Oaktree, LLC, owner of an 80% equity interest in Seminole. Seminole owns a regulated 1,281-mile pipeline (the "Seminole Pipeline System") 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 primary source of throughput for the Seminole system are those volumes originating from the Mid-America system.

The initial funding for these acquisitions was accomplished by entering into a $1.2 billion 364-day credit facility (the "364-Day Term Loan"; see Note 9 for a description of this debt). This temporary credit facility was extinguished in February 2003 when we completed our plans for the permanent financing of these acquisitions (see our discussion of subsequent events in Note 21). These acquisitions did not require any material governmental approvals.

ACQUISITION OF DIAMOND-KOCH PROPYLENE FRACTIONATION BUSINESS IN FEBRUARY 2002

In February 2002, we purchased various propylene fractionation assets and certain inventories of refinery grade propylene, propane, and polymer grade propylene from Diamond-Koch. These include a 66.7% interest in a polymer grade propylene fractionation facility located in Mont Belvieu, Texas (the "Splitter III" facility), a 50% interest in an entity which owns a polymer grade propylene export terminal located on the Houston Ship Channel in La Porte, Texas, and varying interests in several supporting distribution pipelines and related equipment. Splitter III has the capacity to produce approximately 41 MBPD of polymer grade propylene. These assets are part of our Mont Belvieu propylene fractionation operations, which is part of the Fractionation segment. The purchase price of $239.0 million was funded by a drawdown on our Multi-Year and 364-Day Revolving Credit facilities.

ACQUISITION OF DIAMOND-KOCH STORAGE BUSINESS IN JANUARY 2002

In January 2002, we purchased various hydrocarbon storage assets from Diamond-Koch. The storage facility consists of 25 operational salt dome storage caverns with a useable capacity of 64 million barrels, local distribution pipelines and related equipment. The facilities provide storage services for mixed natural gas liquids, ethane, propane, butanes, natural gasoline and olefins (such as ethylene), polymer grade propylene, chemical grade propylene and refinery grade propylene. The facilities are located in Mont Belvieu, Texas and serve the largest petrochemical and refinery complex in the United States. These assets are part of our Mont Belvieu storage operations, which is part of the Pipelines segment. The purchase price of $129.6 million was funded by utilizing cash on hand.

OTHER MINOR ACQUISITIONS COMPLETED DURING 2002

We completed the purchase of an additional interest in our Mont Belvieu NGL fractionator from ChevronTexaco, the acquisition of a gas processing plant and NGL fractionator in Louisiana from Western Resources and certain NGL terminal assets from CornerStone during 2002. Due to the immaterial nature of each of these acquisitions, our discussion of each is limited to the following:

Acquisition of ChevronTexaco's interest in our Mont Belvieu NGL fractionator. Effective June 2002,, we finalized the acquisition of a 12.5% undivided ownership interest in our Mont Belvieu, Texas NGL fractionator from an affiliate of ChevronTexaco. The purchase price of approximately $8.1 million was paid in May 2002. As a result of this transaction, our ownership interest in the Mont Belvieu NGL fractionator increased to 75.0% from 62.5%.

Acquisition of gas processing and NGL fractionator assets from Western Gas Resources, Inc. Effective June 2002, we acquired a 160 MMcf/d natural gas processing plant, a 14.2 MBPD NGL fractionator and supporting assets (including contracts) from Western Gas Resources, Inc. for approximately $32.6 million. The "Toca-Western" facilities are located in St. Bernard Parish, Louisiana near our existing Toca natural gas processing plant.

Acquisition of NGL terminals from CornerStone. In November 2002, we purchased four NGL terminals and existing propane inventories from an affiliate of CornerStone for approximately $11.5 million. The terminals are located in Bakersfield and Rocklin, California; Reno, Nevada and Albertville, Alabama. In addition, we acquired storage facilities related to these terminals with a capacity of 0.1 million barrels. These terminals will support our NGL marketing activities and fee-based marketing services.

ACADIAN GAS POST-CLOSING ADJUSTMENTS COMPLETED IN APRIL 2002

In April 2002, we finalized the post-closing purchase price adjustment associated with our April 2001 acquisition of Acadian Gas. Acadian Gas was acquired from an affiliate of Shell and is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. As a result, we paid Shell $18.0 million for various working capital items, the majority of which were related to natural gas inventories.

ALLOCATION OF AMOUNTS PAID DURING 2002

The acquisitions and post-closing adjustments described previously were accounted for under the purchase method of accounting and, accordingly, the cost of each has been allocated to the assets acquired and liabilities assumed based on their estimated fair values as follows:

	D-K STORAGE	D-K PROPYLENE FRACTIONATION	MID-AMERICA AND SEMINOLE	OTHER	TOTAL
Accounts and Notes receivable			$ 11,777	$ (120)	$ 11,657
Accounts receivable - affiliates			7,799		7,799
Inventories		$ 4,994	10,776	4,403	20,173
Prepaids and other current assets	$ 890	3,148	9,204	416	13,658
Property, plant and equipment	120,571	96,772	1,265,264	24,636	1,507,243
Investments in unconsolidated affiliates		7,550			7,550
Intangible assets	8,127	53,000		31,229	92,356
Goodwill		73,691			73,691
Deferred tax asset			17,307		17,307
Other assets			2,699		2,699
Accounts payable - affiliates			(7,799)		(7,799)
Accrued expenses			(5,529)		(5,529)
Accrued interest			(667)		(667)
Other current liabilities		(107)	(12,226)	8,581	(3,752)
Long-term debt			(60,000)		(60,000)
Other long-term			(90)		(90)
Minority interest			(55,569)		(55,569)
Total purchase price	$ 129,588	$ 239,048	$1,182,946	$ 69,145	$1,620,727

The fair value estimates for both Diamond-Koch transactions; Mid-America and Seminole; the Toca-Western and CornerStone acquisitions were developed by independent appraisers using recognized business valuation techniques. The Mid-America, Seminole and CornerStone allocations are preliminary pending completion of a final review of these businesses which is expected to be completed during the first quarter of 2003. The purchase price allocations related to the Acadian Gas post-closing adjustment and the acquisition of ChevronTexaco's interest in our Mont Belvieu NGL fractionator are based on previously issued fair value reports.

The purchase price paid for the propylene fractionation business resulted in goodwill of $73.7 million. The goodwill primarily represents the value management has attached to future earnings improvements and to the strategic location of the assets. Earnings from the propylene business are expected to improve substantially from the last few years with the years 2005 and 2006 projected to be peak years in the petrochemical business cycle based on industry forecasts. The propylene fractionation assets are located in Mont Belvieu, Texas on the Gulf Coast, the largest natural gas liquids and petrochemical marketplace in the U.S. The assets have access to substantial supply from major Gulf Coast and central U.S. producers of refinery grade propylene. The polymer grade products produced at the facility have competitive advantages because of distribution direct to customers via affiliated pipelines and through an affiliated export facility. For additional information regarding our goodwill, see Note 8.

COMBINED PRO FORMA EFFECT OF MID-AMERICA, SEMINOLE, DIAMOND-KOCH AND ACADIAN GAS BUSINESS ACQUISITIONS

The following table presents unaudited pro forma financial information incorporating the historical (pre-acquisition) financial results of the following acquired businesses:

- D-K storage (acquired January 1, 2002) and propylene fractionation (acquired February 1, 2002);
- Mid-America and Seminole (both acquired July 31, 2002); and
- Acadian Gas (acquired April 1, 2001).

Our historical Statements of Consolidated Operations and Comprehensive Income reflect the operations of each acquired business since their respective acquisition dates.

The following pro forma information has been prepared as if the acquisitions had been completed on January 1 of the respective periods presented as opposed to the actual dates that these acquisitions occurred. The pro forma information is based upon data currently available to and certain estimates and assumptions made by management. As a result, this information is not necessarily indicative of our financial results had the transactions actually occurred on these dates. Likewise, the unaudited pro forma information is not necessarily indicative of our future financial results.

Pro forma net income for each year includes (among other pro forma adjustments) the impact of interest expense associated with the 364-Day Term Loan we used to fund the Mid-America and Seminole acquisitions. The pro forma results for 2001 assume that the initial $1.2 billion borrowed under this facility was outstanding during the entire year. The pro forma results for 2002 reflect our actual repayment of a portion of this debt using proceeds and contributions related to our October 2002 equity offering. The pro forma earnings data do not reflect our January 2003 equity offering nor the Operating Partnership's January 2003 issuance of Senior Notes C or February 2003 issuance of Senior Notes D. The proceeds from these fiscal 2003 equity and debt offerings were used to fully repay the 364-Day Term Loan by the end of February 2003. For additional information regarding these subsequent events, see Note 21.

	FOR YEAR ENDED DECEMBER 31, 2002	2001
PRO FORMA EARNINGS DATA		
Revenues	$ 3,784,286	$ 3,952,896
Operating income	275,272	384,381
Net income	$ 130,528	$ 252,241
Income before minority interest	$ 137,391	$ 259,629
Less: General partner interest	(11,013)	(5,708)
Net income before minority interest available to Limited Partners	126,378	253,921
Less: Minority interest	(6,863)	(7,387)
Net income available to Limited Partners	$ 119,515	$ 246,534
PRO FORMA BASIC EARNINGS PER UNIT		
Numerator:		
Net income before minority interest available to Limited Partners	$ 126,378	$ 253,921
Net income available to Limited Partners	$ 119,515	$ 246,534
Denominator, weighted-average Units outstanding	155,454	139,452
Pro forma diluted earnings per Unit:		
Net income before minority interest available to Limited Partners	$ 0.81	$ 1.82
Net income available to Limited Partners	$ 0.77	$ 1.77
PRO FORMA DILUTED EARNINGS PER UNIT		
Numerator:		
Net income before minority interest available to Limited Partners	$ 126,378	$ 253,921
Net income available to Limited Partners	$ 119,515	$ 246,534
Denominator, weighted-average Units outstanding	176,490	170,786
Pro forma basic earnings per Unit:		
Net income before minority interest available to Limited Partners	$ 0.72	$ 1.49
Net income available to Limited Partners	$ 0.68	$ 1.44

5. INVENTORIES

Our inventories were as follows at the dates indicated:

	DECEMBER 31, 2002	2001
Working inventory	$ 131,769	$ 29,393
Forward-sales inventory	35,600	33,549
Inventory	$ 167,369	$ 62,942

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. 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 2), these volumes are valued at market-related prices during the month in which they are acquired. Like the third-party purchases described above, we inventory the various ancillary costs such as freight-in and other handling and processing amounts associated with owned volumes obtained through our in-kind and similar contracts.

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

- NGL inventory write-downs are recorded as a cost of the Processing segment's NGL marketing activities;
- Natural gas inventory write downs are recorded as a cost of the Pipeline segment's Acadian Gas operations; and
- Petrochemical inventory write downs are recorded as a cost of the Fractionation segment's petrochemical marketing activities.

For the years ended December 31, 2002, 2001 and 2000, we recognized LCM adjustments of approximately $6.3 million, $40.7 million and $6.9 million, respectively. The majority of these write-downs were taken against NGL inventories. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated (or 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, 2002	DECEMBER 31, 2001
Plants and pipelines	5-35	$ 2,860,180	$ 1,398,843
Underground and other storage facilities	5-35	283,114	127,900
Transportation equipment	3-35	5,118	3,736
Land		23,817	15,517
Construction in progress		49,586	98,844
Total		3,221,815	1,644,840
Less accumulated depreciation		410,976	338,050
Property, plant and equipment, net		$ 2,810,839	$ 1,306,790

Depreciation expense for the years ended December 31, 2002, 2001 and 2000 was $72.5 million, $43.4 million and $33.3 million, respectively.

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 method. The investments in and advances to these unconsolidated affiliates are grouped according to the operating 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:

	OWNERSHIP PERCENTAGE	DECEMBER 31, 2002	DECEMBER 31, 2001
Accounted for on equity basis:			
Fractionation:			
BRF	32.25%	$ 28,293	$ 29,417
BRPC	30.00%	17,616	18,841
Promix	33.33%	41,643	45,071
La Porte	50.00%	5,737	
OTC	50.00%	2,178	
Pipeline:			
EPIK	50.00%	11,114	14,280
Wilprise	37.35%	8,566	8,834
Tri-States	33.33%	25,552	26,734
Belle Rose	41.67%	11,057	11,624
Dixie	19.88%	36,660	37,558
Starfish	50.00%	28,512	25,352
Neptune	25.67%	77,365	76,880
Nemo	33.92%	12,423	12,189
Evangeline	49.50%	2,383	2,578
Octane Enhancement:			
BEF	33.33%	54,894	55,843
Accounted for on cost basis:			
Processing:			
VESCO	13.10%	33,000	33,000
Total		$ 396,993	$ 398,201

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

	OWNERSHIP PERCENTAGE	FOR YEAR ENDED DECEMBER 31, 2002	2001	2000
Fractionation:				
BRF	32.25%	$ 2,427	$ 1,583	$ 1,369
BRPC	30.00%	997	1,161	(284)
Promix	33.33%	3,936	4,201	5,306
La Porte	50.00%	(559)		
OTC	50.00%	378		
Pipelines:				
EPIK	50.00%	4,688	345	3,273
Wilprise	37.35%	948	472	497
Tri-States	33.33%	1,959	1,565	2,499
Belle Rose	41.67%	203	103	301
Dixie	19.88%	1,231	2,092	751
Starfish	50.00%	7,346	4,122	
Ocean Breeze	25.67%	-	32	
Neptune	25.67%	2,111	4,081	
Nemo	33.92%	1,077	75	
Evangeline	49.50%	(58)	(145)	
Octane Enhancement:				
BEF	33.33%	8,569	5,671	10,407
Total		$ 35,253	$ 25,358	$ 24,119

At December 31, 2002, our share of accumulated earnings of equity method unconsolidated affiliates that had not been remitted to us was approximately $15.4 million. In addition, our initial investment in Promix, La Porte, Dixie, Neptune and Nemo 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, 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 goodwill inherent in Dixie's excess cost is subject to periodic impairment testing; therefore, it and is not amortized. The following table summarizes our excess cost information:

	INITIAL EXCESS COST	UNAMORTIZED BALANCE AT DECEMBER 31, 2002	UNAMORTIZED BALANCE AT DECEMBER 31, 2001	AMORTIZATION CHARGED AGAINST EQUITY EARNINGS DURING 2002	AMORTIZATION PERIOD
Fractionation segment:					
Promix	$ 7,955	$ 6,596	$ 7,083	$ 398	20 years
La Porte	873	833	n/a	40	35 years
Pipelines segment:					
Dixie					
Attributable to pipeline assets	28,448	26,074	26,887	813	35 years
Goodwill	9,246	8,827	8,827	n/a	n/a
Neptune	12,768	12,039	12,404	365	35 years
Nemo	727	697	718	21	35 years

As used in the following condensed financial data, gross operating margin represents operating income before applicable depreciation and amortization expense and selling, general and administrative costs. Gross operating margin is an important measure of the profitability of assets owned by our unconsolidated affiliates. We regularly evaluate our consolidated operations on the same basis. Operating income represents earnings before non-operating income and expense items such interest expense and interest income. The equity earnings we record from these investments represent our share of the net income of each.

FRACTIONATION SEGMENT:

At December 31, 2002, the Fractionation segment included the following unconsolidated affiliates accounted for using the equity method:

- Baton Rouge Fractionators LLC ("BRF") - an approximate 32.25% interest in an NGL fractionator located in southeastern Louisiana.
- Baton Rouge Propylene Concentrator, LLC ("BRPC") - a 30.0% interest in a propylene fractionator located in southeastern Louisiana.
- K/D/S Promix LLC ("Promix") - a 33.33% interest in an NGL fractionator and related storage and pipeline assets located in south Louisiana.
- 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 are precluded from consolidating its financial statements with our financial statements.
- Olefins Terminal Corporation ("OTC") - a 50% interest in a polymer grade propylene export facility located in Seabrook, Texas. As with La Porte, we do not exercise management control over OTC and are precluded from consolidating its financial statements with our financial statements.

The combined balance sheet information for the last two years and results of operations data for the last three years of the Fractionation segment's equity method investments are summarized below.

	AS OF OR FOR THE YEAR ENDED DECEMBER 31,		
	2002	2001	2000
BALANCE SHEET DATA:			
Current assets	$ 23,496	$ 27,424	
Property, plant and equipment, net	250,096	251,519	
Total assets	$ 273,592	$ 278,943	
Current liabilities	$ 11,229	$ 9,950	
Other liabilities	6,800		
Combined equity	255,563	268,993	
Total liabilities and combined equity	$ 273,592	$ 278,943	
INCOME STATEMENT DATA:			
Revenues	$ 78,350	$ 76,480	$ 71,287
Gross operating margin	40,215	36,321	33,240
Operating income	23,464	22,396	19,997
Net income	23,399	22,738	20,661

PIPELINES SEGMENT:

At December 31, 2002, our Pipelines operating segment included the following unconsolidated affiliates accounted for using the equity method:

- EPIK Terminalling L.P. and EPIK Gas Liquids, LLC (collectively, "EPIK") - a 50% aggregate interest in an NGL export terminal located in southeast Texas. In March 2003, we purchased the remaining ownership interests in EPIK for $19 million plus certain post-closing purchase price adjustments, at which time EPIK became a consolidated subsidiary of ours (see Note 21). Prior to our purchase of the remaining interests, we did not exercise management control over EPIK and were precluded from consolidating its financial statements with our financial statements.
- Wilprise Pipeline Company, LLC ("Wilprise") - a 37.35% interest in an NGL pipeline system located in southeastern Louisiana.
- Tri-States NGL Pipeline LLC ("Tri-States") - an aggregate 33.33% interest in an NGL pipeline system located in Louisiana, Mississippi and Alabama.
- Belle Rose NGL Pipeline LLC ("Belle Rose") - a 41.67% interest in an NGL pipeline system located in south Louisiana.
- Dixie Pipeline Company ("Dixie") - an aggregate 19.88% interest in a 1,301-mile propane pipeline and associated facilities extending from Mont Belvieu, Texas to North Carolina.
- Starfish Pipeline Company LLC ("Starfish") - a 50% interest in a natural gas gathering system 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 LLC ("Neptune") - a 25.67% interest in the natural gas gathering and transmission 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 33.92% interest in a natural gas gathering system located in the Gulf of Mexico offshore Louisiana that became operational in August 2001.
- 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.

The combined balance sheet information for the last two years and results of operations data for the last three years of the Pipelines segment's equity method investments are summarized below:

	AS OF OR FOR THE YEAR ENDED DECEMBER 31,		
	2002	2001	2000
BALANCE SHEET DATA:			
Current assets	$ 76,930	$ 68,325	
Property, plant and equipment, net	510,483	515,327	
Other assets	47,501	50,265	
Total assets	$ 634,914	$ 633,917	
Current liabilities	$ 60,484	$ 62,347	
Other liabilities	56,230	57,965	
Combined equity	518,200	513,605	
Total liabilities and combined equity	$ 634,914	$ 633,917	
INCOME STATEMENT DATA:			
Revenues	$ 303,567	$ 305,404	$ 96,270
Gross operating margin	112,455	98,682	51,414
Operating income	65,855	54,459	41,757
Net income	56,736	41,015	31,241

OCTANE ENHANCEMENT SEGMENT:

At December 31, 2002, the Octane Enhancement segment included our 33.33% interest in Belvieu Environmental Fuels ("BEF"), a facility located in southeast Texas that produces motor gasoline additives to enhance octane. The BEF facility currently produces MTBE. The production of MTBE is driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990 and other legislation and as an additive to increase octane in motor gasoline. Any changes to these oxygenated fuel programs that enable localities to elect to not participate in these programs, lessen the requirements for oxygenates or favor the use of non-isobutane based oxygenated fuels will reduce the demand for MTBE and could have an adverse effect on our results of operations.

In recent years, MTBE has been detected in municipal and private water supplies resulting in various legal actions. BEF has not been named in any MTBE legal action to date. In light of these developments, we and the other two partners of BEF are actively compiling a contingency plan for the BEF facility should MTBE be banned. We are currently evaluating a possible conversion of the facility from MTBE production to alkylate production. In addition to MTBE's value in reducing air pollution, it is a significant source of octane in the U.S. motor gasoline pool. Octane is a critical component of motor gasoline. Therefore, we believe that if MTBE usage is banned or significantly curtailed, the motor gasoline industry would need a substitute additive to maintain octane levels in gasoline and that alkylate would be an economic and effective substitute. We are currently conducting a detailed engineering study that is expected to be completed by the end of 2003, at which time we expect a more definitive conversion cost estimate will be available. The cost to convert the facility will depend on the type of alkylate process chosen and level of alkylate production desired by the partnership.

Balance sheet information for the last two years and results of operations data for the last three years for BEF are summarized below:

	AS OF OR FOR THE YEAR ENDED DECEMBER 31,		
	2002	2001	2000
BALANCE SHEET DATA:			
Current assets	$ 37,237	$ 29,301	
Property, plant and equipment, net	129,019	140,009	
Other assets	9,050	10,067	
Total assets	$ 175,306	$ 179,377	
Current liabilities	$ 16,787	$ 13,352	
Other liabilities	4,017	3,438	
Partners' equity	154,502	162,587	
Total liabilities and Partners' equity	$ 175,306	$ 179,377	
INCOME STATEMENT DATA:			
Revenues	$ 229,358	$ 213,734	$ 258,180
Gross operating margin	71,537	28,701	43,328
Operating income	25,461	15,984	30,529
Net income	25,707	17,014	31,220

PROCESSING SEGMENT:

At December 31, 2002, 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.

8. INTANGIBLE ASSETS AND GOODWILL

INTANGIBLE ASSETS

The following table summarizes our intangible assets at December 31, 2002 and 2001:

		AT DECEMBER 31, 2002		AT DECEMBER 31, 2001	
	GROSS VALUE	ACCUM. AMORT.	CARRYING VALUE	ACCUM. AMORT.	CARRYING VALUE
Shell natural gas processing agreement	$ 206,331	$ (23,015)	$ 183,201	$ (11,962)	$ 194,369
Mont Belvieu Storage II contracts	8,127	(232)	7,895		
Mont Belvieu Splitter III contracts	53,000	(1,388)	51,612		
Toca-Western natural gas processing contracts	11,096	(326)	10,861		
Toca-Western NGL fractionation contracts	20,041	(585)	19,457		
Venice contracts (a)	4,639		4,635		
MBA acquisition goodwill (b)	8,979			(1,122)	7,857
Total	$ 312,213	$ (25,546)	$ 277,661	$ (13,084)	$ 202,226

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(a) Amortization will commence when contracted-volumes begin to be processed in 2003.
(b) Amount reclassified to Goodwill on January 1, 2002 per transition provisions of SFAS 142.

At December 31, 2002, our intangible assets consisted of:

- the Shell natural gas processing agreement that we acquired as part of the TNGL acquisition in August 1999;
- certain storage and propylene fractionation contracts we acquired in connection with the Diamond-Koch acquisitions in January and February 2002;
- certain natural gas processing and NGL fractionation contracts we acquired in connection with the Toca-Western acquisition in June 2002; and
- certain NGL-related contracts (the "Venice contracts") we acquired during the third quarter of 2002.

The following table shows amortization expense associated with our intangible assets for the years ended December 31, 2002, 2001 and 2000:

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Shell natural gas processing agreement	$ 11,054	$ 7,260	$ 3,576
Mont Belvieu Storage II contracts	232		
Mont Belvieu Splitter III contracts	1,388		
Toca-Western natural gas processing contracts	326		
Toca-Western NGL fractionation contracts	585		
MBA acquisition goodwill (a)		449	453
Total	$ 13,585	$ 7,709	$ 4,029

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(a) Our MBA acquisition goodwill is no longer subject to amortization under SFAS 142 guidelines.

The value of the Shell natural gas processing agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term (currently $11.1 million annually from 2002 through 2019). The values of the propylene fractionation and storage contracts acquired from Diamond-Koch are being amortized on a straight-line basis over the economic life of the assets to which they relate, which is currently estimated at 35 years. The Toca-Western natural gas processing contracts are being amortized over the expected 20-year remaining life of the natural gas supplies supporting these contracts. The value of the Toca-Western NGL fractionation contracts is being amortized over the expected 20-year remaining life of the assets to which they relate. The value of the Venice contracts will be amortized over 14 years beginning in the third quarter of 2003.

For 2003, amortization expense attributable to these intangible assets is currently estimated at $14.5 million. Based on information currently available, we expect that amortization expense relating to existing intangibles will increase to $14.7 million during each of the years 2004 through 2007.

GOODWILL

At December 31, 2002, the value of goodwill was $81.5 million. Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired and is comprised of the following (values as of December 31, 2002):

- $73.6 million associated with the purchase of propylene fractionation assets from Diamond-Koch in February 2002; and,
- $7.9 million related to the July 1999 purchase of an additional ownership interest in MBA, which in turn owned an interest in our Mont Belvieu NGL fractionation facility.

Our goodwill amounts are classified as part of the Fractionation segment since they are related to assets recorded in this operating segment. At December 31, 2001, the goodwill associated with the MBA acquisition was recorded as part of our intangible assets.

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 adoption of SFAS No. 142, the only goodwill amortization we recorded was that associated with the MBA acquisition from July 1999. Due to the immaterial nature of such amortization expense (approximately $0.4 million per year), the pro forma effect of not amortizing this goodwill in 2001 or 2000 would have had a negligible effect on our net income and earnings per Unit (both basic and diluted).

9. DEBT OBLIGATIONS

Our debt consisted of the following at:

	DECEMBER 31, 2002	DECEMBER 31, 2001
Borrowings under:		
364-Day Term Loan, variable rate, due July 2003	$ 1,022,000	
364-Day Revolving Credit facility, variable rate, due November 2004	99,000	
Multi-Year Revolving Credit facility, variable rate, due November 2005	225,000	
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	$ 350,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	450,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 2005	45,000	
Total principal amount	2,245,000	854,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,774	1,653
Less unamortized discount on:		
Senior Notes A	(81)	(117)
Senior Notes B	(230)	(258)
Less current maturities of debt	(15,000)	-
Long-term debt	$ 2,231,463	$ 855,278

The table above does not reflect the issuance of our $350 million principal amount Senior Notes C in January 2003 and $500 million principal amount Senior Notes D in February 2003 nor does it reflect the repayment of debt using proceeds from our January 2003 equity offering. We used a combination of proceeds from the issuance of Senior Notes C and D and the January 2003 equity offering to completely repay the 364-Day Term Loan by the end of February 2003 (see the section titled "General description of debt--364-Day Term Loan" within this note for additional information regarding the use of proceeds to extinguish this debt). For additional information regarding subsequent events affecting our debt balances, see Note 21.

As to the assets of our subsidiary, Seminole Pipeline Company, our $2.2 billion in senior indebtedness at December 31, 2002 is structurally subordinated and ranks junior in right of payment to the $45 million of indebtedness of Seminole Pipeline Company. 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, 2002 reflect the classification of such debt obligations at March 7, 2003.

LETTERS OF CREDIT

At December 31, 2002, we had a total of $75 million of standby letters of credit capacity under our Multi-Year Revolving Credit facility, of which $2.4 million was outstanding.

PARENT-SUBSIDIARY GUARANTOR RELATIONSHIPS

Enterprise Products Partners L.P. (the "MLP", on a stand-alone basis) acts as guarantor of certain of the Operating Partnership's debt obligations. These parent-subsidiary guaranty provisions exist under all of our debt obligations with the exception of the Seminole Notes. The Seminole Notes are unsecured obligations solely of

Seminole Pipeline Company. If the Operating Partnership were to default on any guaranteed debt obligation, the MLP would be responsible for full payment of that obligation.

GENERAL DESCRIPTION OF DEBT

The following is a summary of the significant aspects of our debt obligations at December 31, 2002.

364-Day Term Loan. The Operating Partnership entered into a $1.2 billion senior unsecured 364-day term loan to fund the Mid-America and Seminole acquisitions in July 2002. We applied proceeds of $178.8 million from our October 2002 equity offering to partially repay this loan. We used $252.8 million of the $258.9 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 completely repay the 364-Day Term Loan by end of February 2003 (see Note 21). Base variable interest rates under this facility generally bore interest at either (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent or (2) a Eurodollar rate. Whichever base interest rate we selected, the rate was increased by an appropriate applicable margin (as defined within the loan agreement). During 2002, the weighted-average interest rate charged was 3.10%, with the range of rates being between 4.88% and 2.88%. This facility contained various covenants similar to those of our revolving credit facilities. We were in compliance with these covenants at December 31, 2002.

364-Day Revolving Credit facility. In November 2000, , our Operating Partnership entered in a 364-Day revolving credit agreement. Currently, the stand-alone borrowing capacity under this credit facility is $230 million with the maturity date for any amount outstanding being November 2003. We have the option to convert any revolving credit balance outstanding at maturity to a one-year term loan (due November 2004) in accordance with the terms of the credit agreement. This credit facility is guaranteed by the MLP through an unsecured guarantee. In addition, our borrowings under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. We applied $60.0 million in proceeds from our February 2003 issuance of Senior Notes D to reduce the balance outstanding under this facility during 2003 (see Note 21).

As defined by the credit agreement, variable interest rates charged under this facility generally bear interest at either (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent 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. During 2002, the weighted-average interest rate charged for borrowings under this facility was 2.51%, with the range of rates being between 4.75% and 2.37%.

The 364-Day Revolving Credit facility 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 quarter. As defined within 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, 2002. The MLP has entered into an unsecured and unsubordinated guarantee of this debt. This debt is non-recourse to the General Partner.

Multi-Year Revolving Credit facility. In conjunction with the 364-Day Revolving Credit facility, our Operating Partnership entered into a five-year revolving credit facility that includes a sublimit capacity of $75 million for standby letters of credit. Currently, the stand-alone borrowing capacity under this credit facility is $270 million. This credit facility is guaranteed by the MLP through an unsecured guarantee. In addition, our borrowings under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. The interest rates charged under this facility are determined in the same manner as that described under our 364-Day Revolving Credit facility. During 2002, the weighted-average interest rate charged for borrowings under this facility was 2.37%, with the range of rates being between 4.75% and 2.00%.

This facility contains various covenants similar to those of our 364-Day Revolving Credit facility. (please refer to our discussion regarding restrictive covenants of the "364-Day Revolving Credit facility" within this "General description of debt" section). We were in compliance with these covenants at December 31, 2002.

Senior Notes A and B. These fixed-rate notes are an unsecured obligation of the Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. Both notes are guaranteed by the MLP through an unsecured and unsubordinated guarantee and are non-recourse to the General Partner. These notes were issued under an indenture containing certain covenants and are subject to a make-whole redemption right. 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, 2002.

MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, our Operating Partnership entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). This loan is subject to a make-whole redemption right and is guaranteed by MLP through an unsecured and unsubordinated guarantee. The indenture agreement for this loan contains an acceleration clause whereby the outstanding principal and interest on the loan may become due and payable within 120 days if our credit ratings decline below a Baa3 rating by Moody's (currently Baa2) and below a BBB- rating by Standard and Poors (currently BBB). Under these circumstances, the trustee (as defined within the loan agreement) may, and if requested to do so by holders of at least 25% of the principal amount of the underlying bonds, accelerate the maturity of the MBFC Loan. Should this acceleration occur, the entire principal balance of the MBFC Loan and all related accrued and unpaid interest would become immediately due and payable. If such an event occurred, we would have the option of (1) to redeem the MBFC Loan or (2) to provide an alternate credit agreement to support our obligation under the MBFC Loan. We would have 120 days to exercise these options upon receiving notice of the decline in our credit ratings.

The MBFC Loan agreement contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility and restrictions regarding mergers. We were in compliance with these covenants at December 31, 2002.

Seminole Notes. As a result of our acquisition of 78.4% of Seminole in July 2002, we are required to consolidate its debt with our other debt obligations. At December 31, 2002, Seminole had $45 million in fixed-rate senior unsecured notes, of which $15 million is due annually each December through December 2005. The Seminole notes contain various covenants, such as minimum net worth requirements and those restricting Seminole's ability to borrow additional funds. Seminole was in compliance with these covenants at December 31, 2002.

10. CAPITAL STRUCTURE

Our Common Units, Subordinated Units and the convertible Special Units represent limited partner interests in the Company, which entitle the holders thereof to participate in distributions and exercise the rights or privileges available to limited partners 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". Subordinated Units and Special Units are non-voting until their conversion to Common Units.

On February 27, 2002, our General Partner approved a two-for-one split of each class of the partnership Units. The partnership 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. In October 2002, we completed a public offering of 9,800,000 Common Units from which we received net proceeds before offering expenses of approximately $183.3 million, including our General Partner's $3.6 million in capital contributions. The proceeds from this offering were primarily used to repay debt. In January 2003, we completed a public offering of 14,662,500 Common Units from which we received net proceeds of approximately $258.9 million, including our General Partner's $5.3 million in capital contributions (see Note 21).

Our Partnership Agreement sets forth the calculation to be used to determine the amount and priority of cash distributions that the Common and Subordinated Unitholders and the General Partner will receive. 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. Normal allocations according to percentage interests are done only, however, after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated 100% to the General Partner.

As an incentive, the General Partner's percentage interest in quarterly distributions is increased after certain specified target levels are met. On December 17, 2002, we amended our Partnership Agreement to eliminate the General Partner's right to receive 50% of the total cash distributions with respect to that portion of quarterly cash distributions that exceeds $0.392 per Unit. Under the terms of this amendment, our General Partner capped its incentive distribution rights at 25% of the total cash distributions with respect to that portion of quarterly cash distributions that exceeds $0.3085 per Unit. No consideration was paid to the General Partner to give up this right. As amended, the General Partner's quarterly incentive distribution thresholds are as follows:

- 1% of quarterly cash distributions up to $0.253 per Units;
- 14.1% of quarterly cash distributions that exceed $0.253 per Unit up to $0.3085 per Unit; and
- 24.2% of quarterly cash distributions that exceed $0.3085 per Unit.

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 without the approval of Unitholders. During the Subordination Period (as described under "Subordinated Units" below), however, we are limited with regards to the number of equity securities that we may issue that rank senior to Common Units or an equivalent number of securities ranking on a parity with our Common Units, without the approval of the holders of at least a Unit Majority. This limitation does not apply to the issuance of Common Units upon conversion of EPCO's Subordinated Units, issuances pursuant to employee benefit plans, the conversion of the General Partner interest as a result of its withdrawal, or issuances in connection with acquisitions or capital improvements that are accretive on a pro forma per Unit basis (as defined within the Partnership Agreement). A Unit Majority is defined as at least a majority of the outstanding Common Units during the Subordination Period, excluding Common Units held by the General Partner and its affiliates, and at least a majority of the outstanding Common Units after the Subordination Period. For those acquisitions and other transactions that do not meet the aforementioned exceptions, we have 54,550,000 Units available (and unreserved) at December 31, 2002 for general partnership purposes during the Subordination Period.

Subordinated Units. The Subordinated Units have no voting rights until converted into Common Units at the end of the Subordination Period. The Subordination Period will generally extend until the first day of any quarter beginning after June 30, 2003 when the Conversion Tests have been satisfied. Generally, the Conversion Test will have been satisfied when we have paid from Operating Surplus and generated from Adjusted Operating Surplus the minimum quarterly distribution on all Units for each of the three preceding four-quarter periods. Upon expiration of the Subordination Period, all remaining Subordinated Units will convert into Common Units on a one-for-one basis and will thereafter participate pro rata with the other Common Units in distributions of Available Cash.

The Partnership Agreement stipulates that 50% of these may undergo an early conversion into Common Units should certain criteria be satisfied. As a result of meeting the initial criteria, 10,704,936 Subordinated Units (or 25%) converted into Common Units on May 1, 2002. Should the remaining criteria continue to be satisfied through the first quarter of 2003, an additional 25% of these Units would undergo an early conversion into Common Units on May 1, 2003. After that, the remaining 50% would convert on August 1, 2003 if the balance of the conversion requirements are met.

Special Units. The Special Units issued to Shell in conjunction with the 1999 TNGL acquisition and a related contingent unit agreement do not accrue distributions and are not entitled to cash distributions until their conversion into Common Units on a one for one basis. For financial accounting and tax purposes, the Special Units are not allocated any portion of net income; however, for tax purposes, the Special Units are allocated a certain amount of depreciation until their conversion into Common Units.

We issued 29 million Special Units to Shell in August 1999 in connection with TNGL acquisition. Subsequently, Shell met certain performance criteria in 2000 and 2001 that obligated us to issue an additional 12 million Special Units to Shell - 6.0 million were issued in August 2000 and 6.0 million in August 2001 under a contingent unit agreement. Of the cumulative 41 million Special Units issued, 31 million have already converted to Common Units (2.0 million in August 2000, 10.0 million in August 2001 and 19.0 million in August 2002). The remaining 10.0 million Special Units will convert to Common Units on a one for one basis in August 2003. These conversions have a dilutive impact on basic earnings per Unit since they increase the number of Common Units used in the computation. Special Units are excluded from the computation of basic earnings per Unit because, under the terms of the Special Units, they do not share in income nor are they entitled to cash distributions until they are converted to Common Units.

Under the rules of the New York Stock Exchange, the conversion of Special Units into Common Units required the approval of a majority of Common Unitholders. An affiliate of EPCO, which owns in excess of 55% of the outstanding Common Units, voted its Units in favor of such conversion, which provided the necessary votes for approval.

Treasury Units. During the first quarter of 1999, the 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. The Common Units purchased by 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 held by the Company and the 1999 Trust are not considered to be outstanding.

The 1999 Trust purchased 792,800 Common Units during 2001 at a cost of $18.0 million and 100,000 Common Units during 2002 at a cost of $2.4 million. In November 2001, the 1999 Trust sold 1,000,000 Common Units previously held in treasury to EPCO for $22.6 million. The sales price of the treasury Common Units sold exceeded the purchase price of the Treasury Units by $6.0 million and was credited to Partners' Equity accounts in a manner similar to additional paid-in capital. At December 31, 2002, the 1999 Trust held 427,200 Common Units that are classified as Treasury Units.

Beginning in July 2000 and later modified in September 2001, the General Partner authorized the Company (specifically, "Enterprise Products Partners L.P.", in this context) and the 1999 Trust to repurchase up to two million of our publicly-held Common Units (the "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 the Company were to be retired and Common Units repurchased by the 1999 Trust were to remain outstanding and be accounted for as Treasury Units.

In April 2002, management modified the Buy-Back Program to treat Common Units repurchased by the Company as Treasury Units. For accounting purposes, Units repurchased by the Company will be held in treasury . The Company purchased 432,000 Common Units during 2002 at a cost of $10.3 million. At December 31, 2002, an additional 618,400 Common Units could be repurchased under the Buy-Back Program.

During 2002, 51,959 Common Units were reissued from treasury at their weighted-average cost of $1.2 million to fulfill our obligations under certain employee Common Unit option agreements of EPCO.

Unit History. The following table details the outstanding balance of each class of Units at the end of the periods indicated:

	LIMITED PARTNERS			
	COMMON UNITS	SUBORDINATED UNITS	SPECIAL UNITS	TREASURY UNITS
Balance, December 31, 1999	90,571,430	42,819,740	29,000,000	534,400
Additional Special Units issued to Coral Energy, LLC in connection with contingency agreement			6,000,000	
Conversion of 2.0 million Coral Energy, LLC Special Units to Common Units	2,000,000		(2,000,000)	
Units repurchased and retired in connection with buy-back program	(56,800)			
Balance, December 31, 2000	92,514,630	42,819,740	33,000,000	534,400
Additional Special Units issued to Coral Energy, LLC in connection with contingency agreement			6,000,000	
Conversion of 10.0 million Coral Energy, LLC Special Units to Common Units	10,000,000		(10,000,000)	
Treasury Units purchased by consolidated Trust	(792,800)			792,800
Treasury Units reissued by consolidated Trust	1,000,000			(1,000,000)
Balance, December 31, 2001	102,721,830	42,819,740	29,000,000	327,200
Conversion of 19.0 million Coral Energy, LLC Special Units to Common Units	19,000,000		(19,000,000)	
Conversion of 10.7 million Subordinated Units to Common Units	10,704,936	(10,704,936)		
Common Units issued in October 2002	9,800,000			
Treasury Units purchased by consolidated Trust and Company	(532,000)			532,000
Balance, December 31, 2002	141,694,766	32,114,804	10,000,000	859,200

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 $0.2250 per Common Unit. The minimum quarterly distribution is not guaranteed and is subject to adjustment as set forth in the Partnership Agreement. With respect to each quarter during the Subordination Period, the Common Unitholders will generally have the right to receive the minimum quarterly distribution, plus any arrearages thereon, and the General Partner will have the right to receive the related distribution on its interest before any distributions of available cash from Operating Surplus are made to the Subordinated Unitholders.

As an incentive, the General Partner's interest in our quarterly distributions is increased after certain specified target levels are met. We made incentive distributions to the General Partner of $9.8 million, $3.2 million and $0.4 million during the years ended December 31, 2002, 2001 and 2000, respectively.

The following table is a summary of cash distributions per Common and Subordinated Unit and related record and payment dates since January 1, 2000:

CASH DISTRIBUTION HISTORY

	PER COMMON UNIT	PER SUBORDINATED UNIT	RECORD DATE	PAYMENT DATE
2000				
1st Quarter	$0.2500	$0.2500	Apr. 28, 2000	May 10, 2000
2nd Quarter	$0.2625	$0.2625	Jul. 31, 2000	Aug. 10, 2000
3rd Quarter	$0.2625	$0.2625	Oct. 31, 2000	Nov. 10, 2000
4th Quarter	$0.2750	$0.2750	Jan. 31, 2001	Feb. 9, 2001
2001				
1st Quarter	$0.2750	$0.2750	Apr. 30, 2001	May 10, 2001
2nd Quarter	$0.2938	$0.2938	Jul. 31, 2001	Aug. 10, 2001
3rd Quarter	$0.3125	$0.3125	Oct. 31, 2001	Nov. 9, 2001
4th Quarter	$0.3125	$0.3125	Jan. 31, 2002	Feb. 11, 2002
2002				
1st Quarter	$0.3350	$0.3350	Apr. 30, 2002	May 10, 2002
2nd Quarter	$0.3350	$0.3350	Jul. 31, 2002	Aug. 12, 2002
3rd Quarter	$0.3450	$0.3450	Oct. 31, 2002	Nov. 12, 2002
4th Quarter	$0.3450	$0.3450	Jan. 31, 2003	Feb. 12, 2003

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

Provision for income taxes is only applicable to the tax obligation of our Seminole pipeline business, which is a corporation and the only entity subject to income taxes in the consolidated group. The following is a summary of the provision for income taxes for Seminole for the period August 1, 2002 through December 31, 2002:

Current:	
Federal tax benefit	($391)
State tax benefit	(55)
	(446)
Deferred:	
Federal	1,812
State	268
	2,080
Provision for Income Taxes	$1,634

The following is a reconciliation of the provision for income taxes at the federal statutory rate to the provision for income taxes:

Taxes computed by applying the federal statutory rate	$1,488
State income taxes (net of federal benefit)	138
Other	8
Provision for income taxes	$1,634

Significant components of deferred income tax assets and liabilities at December 31, 2002 are as follows:

Deferred tax assets:	
Property, plant and equipment	$15,846
Deferred tax liabilities:	
Other	(619)
Net deferred tax assets	$15,227

Based upon the periods in which taxable temporary differences are anticipated to reverse, we believe it is more likely than not that the Company will realize the benefits of these deductible differences. Accordingly, we believe that no valuation allowance is required for the deferred tax assets. However, the amount of the deferred tax asset considered realizable could be adjusted in the future if estimates of reversing taxable temporary differences are revised.

13. EARNINGS PER UNIT

Basic earnings per Unit is computed by dividing net income available to limited partner interests by the weighted-average number of Common and Subordinated Units outstanding during the period. In general, diluted earnings per Unit is computed by dividing net income available to limited partner interests by the weighted-average number of Common, Subordinated and Special Units outstanding during the period. In a period of net operating losses, the Special 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 amount of Common Units outstanding in the following table does not include Treasury Units (either owned by the Company or the Trust, see Note 10). The following table reconciles the number of Units used in the calculation of basic earnings per Unit and diluted earnings per Unit for the years ended December 31, 2002, 2001 and 2000. See Note 21 for information regarding our January 2003 issuance of 14.7 million Common Units.

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Income before minority interest	$ 98,447	$ 244,650	$ 222,759
General partner interest	(10,663)	(5,608)	(2,597)
Income before minority interest available to Limited Partners	87,784	239,042	220,162
Minority interest	(2,947)	(2,472)	(2,253)
Net income available to Limited Partners	$ 84,837	$ 236,570	$ 217,909
BASIC EARNINGS PER UNIT			
NUMERATOR			
Income before minority interest available to Limited Partners	$ 87,784	$ 239,042	$ 220,162
Net income available to Limited Partners	$ 84,837	$ 236,570	$ 217,909
DENOMINATOR			
Common Units outstanding	119,820	96,633	91,395
Subordinated Units outstanding	35,634	42,820	42,820
Total	155,454	139,453	134,215
BASIC EARNINGS PER UNIT			
Income before minority interest available to Limited Partners	$ 0.56	$ 1.71	$ 1.64
Net income available to Limited Partners	$ 0.55	$ 1.70	$ 1.62
DILUTED EARNINGS PER UNIT			
NUMERATOR			
Income before minority interest available to Limited Partners	$ 87,784	$ 239,042	$ 220,162
Net income available to Limited Partners	$ 84,837	$ 236,570	$ 217,909
DENOMINATOR			
Common Units outstanding	119,820	96,633	91,395
Subordinated Units outstanding	35,634	42,820	42,820
Special Units outstanding	21,036	31,334	30,672
Total	176,490	170,787	164,887
DILUTED EARNINGS PER UNIT			
Income before minority interest available to Limited Partners	$ 0.50	$ 1.40	$ 1.34
Net income available to Limited Partners	$ 0.48	$ 1.39	$ 1.32

14. RELATED PARTY TRANSACTIONS

Relationship with EPCO and its affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates. EPCO is majority-owned and controlled by Dan L. Duncan, Chairman of the Board and a director of the General Partner. In addition, three other members of the Board of Directors (O.S. Andras, Randa D. Williams and Richard H. Bachmann) and the remaining executive and other officers of the General Partner are employees of EPCO. 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 and Subordinated Units held by EPCO. The remaining shares of EPCO capital stock are held primarily by trusts for the benefit of the members of Mr. Duncan's family, including Ms. Williams (a director of the General Partner). In addition, EPCO and Dan Duncan, LLC collectively own 70% of the General Partner, which in turn owns a combined 2% interest in us.

In addition, trust affiliates of EPCO (the 1998 Trust and 2000 Trust) owned 2,478,236 Common Units at December 31, 2002. Collectively, EPCO, Dan L. Duncan, the 1998 Trust and the 2000 Trust owned 61.4% of our limited partnership interests at December 31, 2002. We neither direct the actions of either the 1998 Trust or the 2000 Trust nor exercise any measure of control over their actions. Accordingly, these two trusts are not consolidated with our businesses and their Common Unit holdings are deemed to be outstanding for purposes of our earnings per Unit computations.

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.

EPCO 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 EPCO Agreement. Under the terms of the EPCO Agreement, EPCO agrees to:

- employ the personnel necessary to manage our business and affairs (through the 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 of formulas 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;
- indemnify us against any losses resulting from certain lawsuits; 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 lease payments associated with these assets.

Operating costs and expenses (as shown in the Statements of Consolidated Operations) treat the lease payments being made by EPCO as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded as a general contribution to the partnership. In addition, operating costs and expenses include compensation charges for EPCO's employees who operate our facilities.

Pursuant to the EPCO Agreement, we reimburse 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 who manage our business and affairs. Our reimbursement of EPCO's administrative personnel expense is capped (currently at $17.6 million annually - the "Administrative Services Fee"). The General Partner, with the approval and consent of the Audit and Conflicts Committee, may agree to increases of such fee up to ten percent per year during the 10-year term of the EPCO Agreement. Any difference between the actual costs of this "pre-expansion" group of administrative personnel (including costs associated with equity-based awards granted to certain individuals within this group) and the fee we pay will be borne solely by EPCO. The actual amounts incurred by EPCO did not materially exceed the capped amounts for any periods. We also reimburse EPCO for the compensation of 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.

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.

- EPCO is the operator of the facilities owned by BEF, of which we own 33.3%. In lieu of charging BEF for the actual cost of providing management services, EPCO charges BEF a management fee. EPCO charged BEF $0.6 million for such services during each of 2002, 2001 and 2000.
- EPCO is also operator of the facilities owned by EPIK, which we now wholly own. Prior to February 2003, we owned only 50% of EPIK. In lieu of charging EPIK for the actual cost of management services, EPCO charges EPIK a management fee. During 2002, 2001 and 2000, EPCO charged EPIK $0.3 million, $0.2 million and $0.3 million, respectively, for such services.
- We have entered into an agreement with EPCO to provide trucking services to us for the loading and transportation of products.
- In the normal course of business, we also buy from and sell NGL products to EPCO's Canadian affiliate.

The following table summarizes our various related party transactions with EPCO for the years ended December 31, 2002, 2001 and 2000:

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
REVENUES FROM CONSOLIDATED OPERATIONS			
EPCO	$ 3,630	$ 5,439	$ 4,750
OPERATING COSTS AND EXPENSES			
EPCO	103,210	62,919	52,861
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES			
Base fees payable under EPCO Agreement	16,638	15,125	13,750
Other EPCO compensation reimbursement	7,566	4,824	1,930

Relationship with Shell

We have an extensive and ongoing commercial relationship with Shell as a partner, customer and vendor. Shell, through its subsidiary Shell US Gas & Power LLC, currently owns approximately 20.5% of our limited partnership interests and 30.0% of the General Partner. Currently, three members of the Board of Directors of the General Partner (J. A. Berget, J.R. Eagan, and A.Y. Noojin, III) are employees of Shell.

Shell is our single largest customer. During 2002, it accounted for 7.8% of our consolidated revenues. Our revenues from Shell reflect the sale of NGL and petrochemical products to them and the fees we charge them 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 (see below) and the purchase of NGL products from them. The following table shows our revenues and operating costs and expenses with Shell for the years ended December 31, 2002, 2001 and 2000:

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
REVENUES FROM CONSOLIDATED OPERATIONS			
Shell	$ 282,820	$ 333,333	$ 292,741
OPERATING COSTS AND EXPENSES			
Shell	531,712	705,440	736,655

The most significant contract affecting our natural gas processing business is the 20-year Shell processing agreement, which grants us the right to process Shell's current and future production from state and federal waters of the Gulf of Mexico on a keepwhole basis. This is a life of lease dedication, which may extend the agreement well beyond 20 years. Generally, this contract has the following rights and obligations:

- the exclusive right, but not the obligation, to process substantially all of Shell's Gulf of Mexico natural gas production; plus
- the exclusive right, but not the obligation, 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 plants from Shell's natural gas production from such leases; with
- the obligation to re-deliver to Shell the natural gas stream after the mixed NGL stream is extracted.

Under this contract, we are responsible for reimbursing Shell for the market value of the energy we extract from their natural gas stream in the course of performing natural gas processing services for them. Our reimbursement to Shell (which we record as an operating cost) is generally based upon the energy value of the fuel we consume and the NGLs we extract from their natural gas stream (in terms of its Btu content, a measure of heating value). In lieu of collecting a cash fee for our services under this contract, we take ownership of the NGLs we extract from their natural gas stream. These volumes (our "equity NGL production") become part our inventory held for sale. We derive a profit to the extent that the revenues from the ultimate sale and delivery to customers of these NGLs exceeds the costs of extraction and any other ancillary costs such as fractionation fees.

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 three issues of Special Units granted to Shell in connection with this acquisition);
- the purchase of the Lou-Tex Propylene Pipeline System 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 the Gulf of Mexico natural gas pipelines we acquired from El Paso in 2001. 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 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 $2.2 million in letters of credit on behalf of Evangeline.
- We pay EPIK for export services to load product cargoes for our NGL and petrochemical marketing customers.
- We pay Dixie transportation fees for propane movements on their system initiated by our NGL marketing activities.
- We sell high purity isobutane to BEF as a feedstock and purchase certain of BEF's by-products. We also receive transportation fees for MTBE movements on our HSC pipeline and fractionation revenues for reprocessing mixed feedstock streams generated by BEF.
- 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.

The following table summarizes our related party transactions with unconsolidated affiliates for the years ended December 31, 2002, 2001 and 2000:

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
REVENUES			
Evangeline	$ 131,635	$ 117,283	
EPIK	259	297	$ 5,070
BEF	50,494	45,778	56,216
Promix	12,697	8,952	57
Other unconsolidated affiliates	1,182	1,374	645
OPERATING COSTS AND EXPENSES			
EPIK	19,788	7,438	17,600
Dixie	12,184	12,695	11,763
BEF	9,794	8,073	10,640
Promix	18,408	12,676	18,200
Other unconsolidated affiliates	482	193	

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 the 1998 Plan, non-qualified incentive options to purchase a fixed number of our Common Units (the "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 funds the purchase of the Units under the 1998 Plan at fair value in the open market.

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

Equity-based awards granted to certain key operations personnel. Under the EPCO Agreement (see Note 14), we reimburse EPCO for the compensation of all operations personnel it employs on our behalf. This includes the costs attributable to equity-based awards granted to these personnel. When these employees exercise Unit options, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price for the Units awarded to the employee. We may reimburse EPCO for these costs by either furnishing cash, reissuing Treasury Units or by issuing new Common Units. We record the expense associated with these awards in our operating costs and expenses as shown on our Statements of Consolidated Operations.

Equity-based awards granted to certain key expansion-related administrative and management employees. We also reimburse EPCO for the compensation of administrative and management 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 "expansion" group of EPCO employees. When these employees exercise Unit options, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price for the Units awarded to the employee. We may reimburse EPCO for these costs by either furnishing cash, reissuing Treasury Units or by issuing new Common Units. We record the expense associated with these awards in our selling, general and administrative costs as shown on our Statements of Consolidated Operations.

Equity-based awards granted to other key administrative and management employees. In addition, we reimburse EPCO for our share of the costs of certain of its employees in administrative and management positions that were active at the time of our initial public offering in July 1998 who manage our business and affairs. Our reimbursement for the cost of equity-based awards to this "pre-expansion" group of administrative EPCO employees is covered by the Administrative Services Fee we pay to EPCO. EPCO is responsible for the actual costs when the

Unit options granted to these pre-expansion administrative employees are exercised. EPCO satisfies its equity-award obligations to these employees by arranging for Common Units to be purchased in the open market. We record the Administrative Service Fee paid to EPCO as a selling, general and administrative expense as shown on our Statements of Consolidated Operations.

Summary of 1998 Plan activity and amounts related to Employees who perform activities on our behalf

EPCO's 1998 Plan is used to issue Unit option awards to the three categories of employees discussed above. The information in the following table shows (i) Unit option activity for all operations and expansion -related administrative/management personnel and (ii) Unit option activity of the pre-expansion administrative/management employees allocable to us under the EPCO Agreement (based on each pre-expansion employee's percentage of time worked on our behalf).

	NUMBER OF UNITS	WEIGHTED-AVERAGE STRIKE PRICE
Outstanding at December 31, 1999	178,611	$ 1.95
Granted	664,000	$ 9.26
Exercised	(38,180)	$ 1.84
Forfeited	(20,000)	$ 9.00
Outstanding at December 31, 2000	784,431	$ 7.96
Granted	680,000	$ 16.67
Exercised	(150,585)	$ 6.01
Forfeited	(20,000)	$ 9.00
Outstanding at December 31, 2001	1,293,846	$ 12.74
Granted	249,000	$ 23.76
Exercised	(102,604)	$ 6.16
Outstanding at December 31, 2002	1,440,242	$ 15.12
Options exercisable at:		
December 31, 2000	140,431	
December 31, 2001	155,846	
December 31, 2002	383,742	

RANGE OF STRIKE PRICES	OPTIONS OUTSTANDING AT DECEMBER 31, 2002	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE(IN YEARS)	WEIGHTED AVERAGE STRIKE PRICE	OPTIONS EXERCISABLE AT DECEMBER 31, 2002: NUMBER EXERCISABLE AT DECEMBER 31, 2002	WEIGHTED AVERAGE STRIKE PRICE
$.69 - $2.23	52,242	2.16	$ 1.58	52,242	$ 1.98
$7.75 -$9.00	331,500	6.75	$ 8.82	331,500	$ 8.82
$11.81	127,500	7.09	$ 11.81	-	-
$15.93 - $17.63	615,000	8.10	$ 16.30	-	-
$21.22 - $24.73	314,000	9.09	$ 23.61	-	-
	1,440,242			383,742	

The weighted average fair value of options granted was $3.17, $1.86, and $2.23 per option for the fiscal years ended December 31, 2002, 2001, and 2000, respectively.

We apply Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees", in accounting for employee Unit option awards whereby no compensation expense is recorded related to the options granted equal to the market value of the Unit on the date of grant. If compensation expense had been determined based on the Black-Scholes option pricing model value at the grant date for Unit option awards consistent with the provisions of SFAS No. 123, "Accounting for Stock-Based Compensation", our net income and earnings per unit would have been as follows:

	2002	2001	2000
Net income:			
As reported........................	$95,500	$242,178	$220,506
Pro forma..........................	94,406	241,348	219,844
Basic earnings per unit:			
As reported........................	$ .55	$ 1.70	$ 1.62
Pro forma..........................	.54	1.69	1.62
Diluted earnings per unit:			
As reported........................	$ .48	$ 1.39	$ 1.32
Pro forma..........................	.48	1.38	1.32

The effects of applying SFAS No. 123 in the pro forma disclosure above may not be indicative of future amounts as additional awards in future years are anticipated.

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

	2002	2001	2000
Expected life of options................	7 years	7 years	7 years
Risk-free interest rate.................	3.10%	3.83%	6.44%
Expected dividend yield.................	5.65%	5.30%	10.00%
Expected Unit price volatility..........	25%	20%	30%

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, 2002, NGL and petrochemical volumes aggregating 4.2 million barrels were due to be redelivered to their owners along with 664 BBtus of natural gas.

Lease Commitments

We lease certain equipment and processing facilities under noncancelable and cancelable operating leases. Minimum future rental payments on such leases with terms in excess of one year at December 31, 2002 are as follows:

2003	$ 7,148
2004	5,081
2005	759
2006	676
2007	506
Thereafter	3,623
Total minimum obligations	$ 17,793

Third-party lease and rental expense included in operating income for the years ended December 31, 2002, 2001 and 2000 was approximately $16.4 million, $13.0 million and $10.6 million.

The operating lease commitments shown above 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 $12.6 million for 2003, $2.1 million for each of the years 2004 through 2009 and $0.7 million from 2010 through 2016. EPCO has assigned to us the purchase options associated with the retained leases. Should we decide to exercise our purchase options under the retained leases (which are at fair market value), up to $26.0 million is expected to be payable in 2004, $3.4 million in 2008 and $3.1 million in 2016.

Purchase Commitments

Product purchase commitments. We have long-term purchase commitments for NGLs, petrochemicals and natural gas with several 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 long-term volume commitments under these contracts.

	NGLS	PETROCHEMICALS	NATURAL GAS
	(MBbls)	(MBbls)	(BBtus)
2003	15,986	25,428	23,053
2004	13,172	22,857	20,439
2005	9,580	19,287	18,645
2006	5,910	13,399	18,645
2007	5,400	1,125	18,250
Thereafter	10,800		91,250
	60,848	82,096	190,282

Capital spending commitments. As of December 31, 2002, we had capital expenditure commitments totaling approximately $7.8 million, of which $6.3 million relates to our share of capital projects of unconsolidated affiliates.

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 (see Note 15). At December 31, 2002, there were 1,194,242 options outstanding to purchase Common Units under the 1998 Plan that had been granted to operational and expansion-related administrative employees for which we were responsible for reimbursing EPCO for the costs of such awards. The weighted-average strike price of the Unit option awards granted to this group was $15.73 per Common Unit. At December 31, 2002, 275,242 of these Unit options were exercisable. An additional 100,000, 570,000 and 249,000 of these Unit options will be exercisable in 2003, 2004 and 2005, respectively.

When these operations and expansion-related administrative employees exercise a Unit option, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price paid for the Units awarded to the employee. We may reimburse EPCO for these costs by either furnishing cash, reissuing Treasury Units or by issuing new Common Units.

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,		
	2002	2001	2000
(Increase) decrease in:			
Accounts and notes receivable	$ (127,365)	$ 231,532	$ (93,716)
Inventories	(84,254)	11,048	(13,044)
Prepaid and other current assets	15,340	(26,427)	2,352
Intangible assets			(5,226)
Other assets	(3,322)	162	(1,410)
Increase (decrease) in:			
Accounts payable	23,901	(82,075)	18,723
Accrued gas payable	262,527	(178,102)	135,049
Accrued expenses	7,884	(1,576)	4,978
Accrued interest	5,369	14,234	8,743
Other current liabilities	(6,921)	3,073	6,540
Other liabilities	(504)	(9,012)	8,122
Net effect of changes in operating accounts	$ 92,655	$ (37,143)	$ 71,111
Cash payments for interest, net of $1,083, $2,946 and $3,277 capitalized in 2002, 2001 and 2000, respectively	$ 82,535	$ 37,536	$ 17,774

During 2002 and 2001, we completed $1.8 billion in business acquisitions of which the purchase price allocation of each affected various balance sheet accounts. See Note 4 for information regarding the purchase price allocations of these transactions during 2002. During 2001, we acquired Acadian Gas from Shell. Its $225.7 million purchase price was allocated as follows: $83.1 million to current assets, $225.2 million to property, plant and equipment, $2.7 million to investments in unconsolidated affiliates, $83.9 million to current liabilities and $1.4 million to other long-term liabilities.

We record various financial instruments relating to commodity positions and interest rate hedging activities at their respective fair values using mark-to-market accounting. 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 2002, we made the first of two cash payments to acquire certain processing-related contract rights connected to Venice gas processing facility. Of the initial $4.6 million value of this intangible asset, $2.6 million was reclassified from construction-in-progress and $2.0 million represented the actual cash payment made to the third-party. 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. The remaining $2.0 million is scheduled to be paid during the third quarter of 2003.

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, 2002 and 2001 was $8.8 million and $5.8 million, respectively.

We did not have any cash payments for income taxes during 2002, 2001 or 2000. For additional information regarding our partnership and income taxes, see Note 1 and Note 12.

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 Processing 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 Processing 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 Fractionation segment. In our Pipelines 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. 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 Other 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 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, 2002, we had open commodity financial instruments that settle at different dates through December 2003. 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 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, 2002. The fair value of these open positions was a liability of $26 thousand (based on market prices at that date).

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 will be 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.

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 are accounted for as cash flow hedges under 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 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 21). The settlement of these instruments resulted in our receipt of $5.4 million of cash. This amount will be 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 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 estimated amount to be reclassified from accumulated other comprehensive income to earnings during 2003 is $0.4 million. With the settlement of the treasury locks, the $3.6 million non-cash mark-to-market liability recorded at December 31, 2002 will be 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, the FASB is continuing to provide guidance about implementation issues. Since this guidance is still continuing, our initial conclusions regarding the application of SFAS No. 133 upon adoption may be altered. As a result, additional SFAS No. 133 transition 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, 2002 and 2001:

FINANCIAL INSTRUMENTS	AT DECEMBER 31, 2002		AT DECEMBER 31, 2001	
	CARRYING VALUE	FAIR VALUE	CARRYING VALUE	FAIR VALUE
Financial assets:				
Cash and cash equivalents	$ 22,568	$ 22,568	$ 137,823	$ 137,823
Accounts receivable	399,415	399,415	260,399	260,399
Commodity financial instruments (1)	513	513	9,992	9,992
Interest rate hedging financial instruments (2)	203	203	2,324	2,324
Financial liabilities:				
Accounts payable and accrued expenses	663,715	663,715	357,951	357,951
Fixed-rate debt (principal amount)	899,000	1,027,749	854,000	894,005
Variable-rate debt	1,346,000	1,346,000		
Commodity financial instruments (1)	539	539	3,206	3,206
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 have 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

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 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. As a result, we established a $10.7 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.

Nature of Operations. 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.

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 five reportable operating segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. The reportable segments are generally organized according to the type of services rendered (or process employed) and products produced and/or sold, as applicable. The segments are regularly evaluated by the Chief Executive Officer of the General Partner. Pipelines consists of NGL, petrochemical and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization, and polymer grade propylene fractionation services. Processing includes the natural gas processing business and its related NGL marketing activities. Octane Enhancement represents our equity interest in BEF, a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other operating segment consists of fee-based marketing services and various operational support activities.

We evaluate segment performance based on our measurement of segment gross operating margin. Gross operating margin reported for each segment represents operating income before depreciation and amortization, lease expense obligations retained by EPCO, gains and losses on the sale of assets and general and administrative expenses. In addition, segment gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges.

Gross operating margin by segment includes intersegment and intrasegment revenues (offset by corresponding intersegment and intrasegment expenses within the segments), which are generally based on transactions made at market-related rates. Our intersegment and intrasegment activities include, but are not limited to, the following types of transactions:

- NGL fractionation revenues from separating our NGL raw-make inventories into distinct NGL products using our fractionation plants for our NGL marketing activities (an intersegment revenue of Fractionation offset by an intersegment expense of Processing);
- liquids pipeline revenues from transporting our NGL volumes from gas processing plants on our pipelines to our NGL fractionation facilities (an intersegment revenue of Pipelines offset by an intersegment expense of Processing); and,
- the transfer sale of our NGL equity production extracted by our gas processing plants to our NGL marketing activities (an intrasegment revenue of Processing offset by an intrasegment expense of Processing).

For additional information regarding our revenue recognition policies, see Note 2.

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries, after elimination of all material intercompany (both intersegment and intrasegment) accounts and 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 and a means by which we conduct our operations to align our interests with a supplier of raw materials to a facility or a consumer of finished products from a facility. 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 our equity investees (see Note 7) perform supporting or complementary roles to our other business operations. For example, we use the Promix NGL fractionator to process NGLs extracted by our gas plants. The NGLs received from Promix then can be sold by our Processing segment's NGL marketing activities. Another example would be our relationship with the BEF MTBE facility. Our isomerization facilities process normal butane for this plant and our HSC pipeline transports MTBE for delivery to BEF's storage facility on the Houston Ship Channel. For additional information regarding our related party relationships with unconsolidated affiliates, see Note 14.

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 primarily along the western Gulf Coast in Texas, Louisiana and Mississippi. Our pipelines and related operations are in a number of regions of the United States including the Gulf of Mexico offshore Louisiana (certain natural gas pipelines); the south and southeastern United States (primarily in the Texas, Louisiana and Mississippi regions); and certain regions of the central and western United States. The Mid-America pipeline system extends from the Hobbs hub located on the Texas-New Mexico border to Wyoming along one route and to Minnesota, Wisconsin and Illinois along other routes. 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 property is construction-in-progress. Segment property represents those facilities and projects that contribute to gross operating margin and is net of accumulated depreciation on these assets. Since assets under construction do not generally contribute to segment gross operating margin, these assets are not included in the operating segment totals until they are deemed operational. Consolidated intangible assets and goodwill are allocated to the segments based on the classification of the assets to which they relate.

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

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Revenues (1)	$ 3,584,783	$ 3,154,369	$ 3,049,020
Operating costs and expenses (1)	(3,382,561)	(2,861,743)	(2,801,060)
Equity in income of unconsolidated affiliates (2)	35,253	25,358	24,119
Subtotal	237,475	317,984	272,079
Add: Depreciation and amortization in operating costs and expenses (3)	86,029	48,775	35,621
Retained lease expense, net in operating costs and expenses (4)	9,124	10,414	10,645
(Gain) loss on sale of assets in operating costs and expenses (3)	(1)	(390)	2,270
Total segment gross operating margin	$ 332,627	$ 376,783	$ 320,615

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(1) Amounts are comprised of both third party and related party totals from the Statements of Consolidated Operations and Comprehensive Income

(2) Amount taken from Statements of Consolidated Operations and Comprehensive Income

(3) Amount taken from Statements of Consolidated Cash Flows

(4) Amount represents leases paid by EPCO and the related contribution by the minority interest as reflected on the Statements of Consolidated Cash Flows

A reconciliation of our measurement of total segment gross operating margin to consolidated income before provision for income taxes and minority interest follows:

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Total segment gross operating margin	$ 332,627	$ 376,783	$ 320,615
Depreciation and amortization	(86,029)	(48,775)	(35,621)
Retained lease expense, net	(9,124)	(10,414)	(10,645)
Gain (loss) on sale of assets	1	390	(2,270)
Selling, general and administrative	(42,890)	(30,296)	(28,345)
Consolidated operating income	194,585	287,688	243,734
Interest expense	(101,580)	(52,456)	(33,329)
Interest income from unconsolidated affiliates	139	31	1,787
Dividend income from unconsolidated affiliates	4,737	3,462	7,091
Interest income - other	2,313	7,029	3,748
Other, net	(113)	(1,104)	(272)
Consolidated income before provision for income taxes and minority interest	$ 100,081	$ 244,650	$ 222,759

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

	Operating Segments						
	Fractionation	Pipelines	Processing	Octane Enhancement	Other	Adjs. and Elims.	Consol. Totals
Revenues from third parties:							
2002	$ 592,681	$ 458,427	$ 2,049,202		$ 1,756		$ 3,102,066
2001	301,263	239,489	2,100,224		937		2,641,913
2000	361,919	15,648	2,310,706		1,268		2,689,541
Revenues from related parties:							
2002	19,121	161,727	301,747		122		482,717
2001	23,013	163,941	324,057		1,445		512,456
2000	35,076	12,524	310,269		1,610		359,479
Intersegment and intrasegment revenues:							
2002	203,750	102,330	604,981		401	$ (911,462)	-
2001	158,853	89,907	683,524		389	(932,673)	-
2000	177,963	55,690	630,155		375	(864,183)	-
Total revenues:							
2002	815,552	722,484	2,955,930		2,279	(911,462)	3,584,783
2001	483,129	493,337	3,107,805		2,771	(932,673)	3,154,369
2000	574,958	83,862	3,251,130		3,253	(864,183)	3,049,020
Equity income in unconsolidated affiliates:							
2002	7,179	19,505		$ 8,569			35,253
2001	6,945	12,742		5,671			25,358
2000	6,391	7,321		10,407			24,119
Total gross operating margin by segment:							
2002	129,000	214,932	(17,633)	8,569	(2,241)		332,627
2001	118,610	96,569	154,989	5,671	944		376,783
2000	129,376	56,099	122,240	10,407	2,493		320,615
Segment property (see Note 6):							
2002	444,016	2,166,524	133,888		16,825	49,586	2,810,839
2001	357,122	717,348	124,555		8,921	98,844	1,306,790
Investments in and advances to unconsolidated affiliates (see Note 7):							
2002	95,467	213,632	33,000	54,894			396,993
2001	93,329	216,029	33,000	55,843			398,201
Intangible Assets (see Note 8):							
2002	71,069	7,895	198,697				277,661
2001	7,857		194,369				202,226
Goodwill (see Note 8):							
2002	81,547						81,547

In general, our consolidated results of operations and financial position have been materially affected by acquisitions since late 1999. Our more significant acquisitions during this period were:

- William's Mid-America and Seminole pipelines in July 2002 for $1.2 billion;
- Diamond-Koch's propylene fractionation business in February 2002 for $239 million ;
- Diamond-Koch's NGL and petrochemical storage business in January 2002 for $129.6 million;
- Shell's Acadian Gas pipeline business in April 2001 for $243.7 million;
- El Paso's equity interests in four Gulf of Mexico natural gas pipelines in January 2001 for $113 million; and
- Shell's TNGL natural gas processing and related businesses in August 1999 for approximately $528.8 million.

See Note 4 for a description of acquisitions we completed during 2002.

21. SUBSEQUENT EVENTS

January 2003 Common Unit Offering. In January 2003, we completed a public offering of 14,662,500 Common Units (including 1,912,500 Common Units sold pursuant to the underwriters' over-allotment option) from which we received net proceeds before offering expenses of approximately $258.9 million, including our General Partner's $5.3 million in capital contributions. We used $252.8 million of the proceeds from this offering to repay a portion of the indebtedness outstanding under the 364-Day Term Loan. The remaining balance of proceeds was used for working capital purposes and offering expenses.

January 2003 Senior Notes Offering. In January 2003, our Operating Partnership issued $350 million in principal amount of 6.375% Senior Notes due 2013 ("Senior Notes C"), from which we received net proceeds before offering expenses of approximately $347.7 million. We used $347.0 million of the proceeds from this offering to repay a portion of the indebtedness outstanding under the 364-Day Term Loan. The remaining balance of proceeds was used for offering expenses.

February 2003 Senior Notes Offering. In February 2003, our Operating Partnership issued $500 million in principal amount of 6.875% Senior Notes due 2033 ("Senior Notes D"), from which we received net proceeds before offering expenses of approximately $489.8 million. We used $421.4 million of the proceeds from this offering to repay the remaining principal balance outstanding under the 364-Day Term Loan. An additional $60.0 million in proceeds was used to reduce the amount outstanding under the 364-Day Revolving Credit facility. The remaining balance of proceeds was used for working capital purposes and offering expenses.

Purchase of remaining 50% interest in EPIK. In March 2003, we purchased the remaining ownership interests in EPIK from Idemitsu LPG USA Corporation for $19.0 million. The purchase price is subject to certain post-closing adjustments that we expect to finalize during the second quarter of 2003.

22. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table contains selected quarterly financial data for 2002 and 2001.

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
FOR THE YEAR ENDED DECEMBER 31, 2001:				
Revenues	$ 836,315	$ 959,397	$ 723,329	$ 635,328
Operating income	54,417	109,071	87,406	36,794
Income before minority interest	52,804	93,975	75,774	22,097
Minority interest	(534)	(944)	(767)	(227)
Net income	52,270	93,031	75,007	21,870
Net income per Unit, basic	$ 0.38	$ 0.68	$ 0.52	$ 0.14
Net income per Unit, diluted	$ 0.30	$ 0.54	$ 0.43	$ 0.12
FOR THE YEAR ENDED DECEMBER 31, 2002:				
Revenues	$ 662,054	$ 786,257	$ 943,313	$ 1,193,159
Operating income	(1,104)	39,964	68,356	87,369
Income before minority interest	(17,376)	22,523	36,146	57,154
Minority interest	173	(203)	(1,296)	(1,621)
Net income (loss)	(17,203)	22,320	34,850	55,533
Net income (loss) per Unit, basic	$ (0.13)	$ 0.14	$ 0.20	$ 0.30
Net income (loss) per Unit, diluted	$ (0.13)	$ 0.11	$ 0.18	$ 0.28

We recorded a net loss during the first quarter of 2002 due to commodity hedging losses resulting from an unexpected increase in natural gas prices. Overall, we recorded $51.3 million of commodity hedging losses during 2002 compared to $101.3 million of income from such activities during 2001 (see Note 18). Net income for the second half of 2002 improved relative to the first half of 2002 primarily due to the acquisition of Mid-America and Seminole in July 2002 (see Note 4).

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					
2002	$ 20,642		$ 5,367 (b)	$ (4,813) (d)	$ 21,196
2001	10,916	$ 6,200 (a)	6,522 (c)	(2,996) (d)	20,642
2000	15,871			(4,955) (d)	10,916
OTHER CURRENT ASSETS:					
Additional credit reserve for Enron					
2002	$ 4,305			$ (4,305) (b)	
2001			4,305 (a)		4,305
OTHER CURRENT LIABILITIES:					
Reserve for environmental liabilities					
2002			102 (e)	(93) (e)	9
Reserve for inventory gains and losses (f)					
2002	2,029	500 (g)		(1,258) (h)	1,271
2001	5,690	500 (g)		(4,161) (h)	2,029
2000	2,894	500 (g)	2,296 (h)		5,690
OTHER LONG-TERM LIABILITIES:					
Reserve for environmental liabilities					
2002		45 (e)	90 (e)		135

The following explanations describe significant transactions affecting the amounts shown in the table above:

(a) In December 2001, Enron North America filed for protection under Chapter 11 of the U.S. Bankruptcy Code. As a result, we established a $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, $6.3 million offsets billed amounts due from Enron recorded in Accounts Receivable-Trade. The remaining $4.3 million in reserve offsets various unbilled commodity financial instrument positions, which were reclassified to "Additional credit reserve from Enron".

(b) The $4.3 million in unbilled positions was invoiced in early 2002 as the financial instruments settled (see Note 19). These amounts were reclassified from the "Additional credit reserve for Enron" account to "Allowance for doubtful accounts" accordingly.

(c) The allowance account was increased in April 2001 as a result of accounts acquired from Acadian Gas.

(d) In the normal course of business, we charged the allowance account for customer amounts that have been deemed uncollectible.

(e) In July 2002, we acquired the Mid-America pipeline from Williams. This operation had existing minor environmental liabilities that were of a current and long-term nature that we recorded using purchase accounting. Since the acquisition, various vendor invoices have been charged against the current portion of the reserve. In addition, the long-term portion of the reserve has been increased due to revisions in management estimates of the future liability to remediate the sites involved.

(f) 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.

(g) The reserve is increased based on management's estimate of annual net product storage losses.

(h) Product losses are charged against and reduce the reserve balance. 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 adjusted by $2.4 million.

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Enterprise Products Operating L.P. and subsidiaries (the "Company") as of December 31, 2002 and 2001, and the related statements of consolidated operations and other comprehensive income, consolidated cash flows and consolidated partners' equity for each of the three years in the period ended December 31, 2002. Our audits also included the consolidated financial statement schedule of the Company listed in the Index to the Financial Statements. 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 auditing standards generally accepted in the United States of America. 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, 2002 and 2001, and the results of its consolidated operations and its consolidated cash flows for each of the three years in the period ended December 31, 2002 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 7, 2003

ENTERPRISE PRODUCTS OPERATING L.P.
CONSOLIDATED BALANCE SHEETS
(DOLLARS IN THOUSANDS)

	DECEMBER 31, 2002	DECEMBER 31, 2001
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents (includes restricted cash of $8,751 at December 31, 2002 and $5,752 at December 31, 2001)	$ 20,795	$ 137,823
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $21,196 at December 31, 2002 and $20,642 at December 31, 2001	399,187	256,024
Accounts receivable - affiliates	3,369	4,405
Inventories	167,369	62,942
Prepaid and other current assets	48,137	51,110
Total current assets	638,857	512,304
PROPERTY, PLANT AND EQUIPMENT, NET	2,810,839	1,306,790
INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES	396,993	398,201
INTANGIBLE ASSETS, NET OF ACCUMULATED AMORTIZATION OF $25,546 AT DECEMBER 31, 2002 AND $13,084 AT DECEMBER 31, 2001	277,661	202,226
GOODWILL	81,547	
DEFERRED TAX ASSET	15,846	
OTHER ASSETS	9,818	5,201
TOTAL	$ 4,231,561	$ 2,424,722
LIABILITIES AND PARTNERS' EQUITY		
CURRENT LIABILITIES		
Current maturities of long-term debt	$ 15,000	
Accounts payable - trade	67,283	$ 54,269
Accounts payable - affiliates	40,773	33,691
Accrued gas payables	489,562	227,035
Accrued expenses	35,760	22,233
Accrued interest	30,338	24,302
Other current liabilities	42,644	44,767
Total current liabilities	721,360	406,297
LONG-TERM DEBT	2,231,463	855,278
OTHER LONG-TERM LIABILITIES	7,666	8,061
MINORITY INTEREST	59,336	1,468
COMMITMENTS AND CONTINGENCIES		
PARTNERS' EQUITY		
Limited Partner	1,211,593	1,148,124
General Partner	12,363	11,716
Parent's Units acquired by Trust	(8,660)	(6,222)
Accumulated Other Comprehensive Loss	(3,560)	
Total Partners' Equity	1,211,736	1,153,618
TOTAL	$ 4,231,561	$ 2,424,722

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS OPERATING L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS AND COMPREHENSIVE INCOME
(DOLLARS IN THOUSANDS)

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
REVENUES			
Revenues from consolidated operations			
Third parties	$ 3,102,066	$ 2,641,913	$ 2,689,541
Related parties	482,717	512,456	359,479
Total revenues	3,584,783	3,154,369	3,049,020
COST AND EXPENSES			
Operating costs and expenses			
Third parties	2,686,982	2,052,321	1,953,341
Related parties	695,579	809,422	847,719
Selling, general and administrative			
Third parties	18,460	10,863	12,665
Related parties	24,204	19,949	15,680
Total costs and expenses	3,425,225	2,892,555	2,829,405
EQUITY IN INCOME OF UNCONSOLIDATED AFFILIATES	35,253	25,358	24,119
OPERATING INCOME	194,811	287,172	243,734
OTHER INCOME (EXPENSE)			
Interest expense	(101,580)	(52,456)	(33,329)
Interest income from related parties	139	15	1,662
Dividend income from unconsolidated affiliates	4,737	3,462	7,091
Interest income - other	2,846	7,773	4,295
Other, net	(230)	(1,104)	(272)
Other income (expense)	(94,088)	(42,310)	(20,553)
INCOME BEFORE PROVISION FOR INCOME TAXES AND MINORITY INTEREST	100,723	244,862	223,181
PROVISION FOR INCOME TAXES	(1,634)		
INCOME BEFORE MINORITY INTEREST	99,089	244,862	223,181
MINORITY INTEREST	(2,137)	(144)	(113)
NET INCOME	96,952	244,718	223,068
Cumulative transition adjustment related to financial instruments recorded upon adoption of SFAS No. 133 (see Note 16)		(42,190)	
Reclassification of cumulative transition adjustment to earnings		42,190	
Change in fair value of financial instruments recorded as cash flow hedges	(3,560)		
COMPREHENSIVE INCOME	$ 93,392	$ 244,718	$ 223,068

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS OPERATING L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(DOLLARS IN THOUSANDS)

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
OPERATING ACTIVITIES			
Net income	$ 96,952	$ 244,718	$ 223,068
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:			
Depreciation and amortization in operating costs and expenses	86,029	48,775	35,621
Depreciation in selling, general and administrative costs	77	2,341	1,689
Amortization in interest expense	8,819	787	3,735
Equity in income of unconsolidated affiliates	(35,253)	(25,358)	(24,119)
Distributions received from unconsolidated affiliates	57,662	45,054	37,267
Leases paid by EPCO	9,125	10,414	10,644
Minority interest	2,137	144	113
Loss (gain) on sale of assets	(1)	(390)	2,270
Deferred income tax expense	2,080		
Changes in fair market value of financial instruments (see Note 16)	10,213	(5,697)	
Net effect of changes in operating accounts	86,045	(34,663)	68,635
Operating activities cash flows	323,885	286,125	358,923
INVESTING ACTIVITIES			
Capital expenditures	(72,135)	(149,896)	(243,913)
Proceeds from sale of assets	165	568	92
Business acquisitions, net of cash acquired	(1,620,727)	(225,665)	
Acquisition of intangible asset	(2,000)		
Collection of note receivable from unconsolidated affiliate			6,519
Investments in and advances to unconsolidated affiliates	(13,651)	(116,220)	(31,496)
Investing activities cash flows	(1,708,348)	(491,213)	(268,798)
FINANCING ACTIVITIES			
Borrowings under debt agreements	1,968,000	449,717	598,818
Repayments of debt	(637,000)		(490,000)
Debt issuance costs	(19,329)	(3,125)	(4,043)
Cash distributions to partners	(224,470)	(167,044)	(141,472)
Cash distributions to minority interest	(1,191)	(59)	(146)
Cash contributions from partners	182,509		
Cash contributions from minority interest	1,354	379	5
Parent's Units acquired by consolidated Trust	(2,438)	(18,003)	
Parent's Units reissued by consolidated Trust		22,600	
Increase in restricted cash	(2,999)	(5,752)	
Financing activities cash flows	1,264,436	278,713	(36,838)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(120,027)	73,625	53,287
CASH AND CASH EQUIVALENTS, JANUARY 1	132,071	58,446	5,159
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 12,044	$ 132,071	$ 58,446

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS OPERATING L.P.
STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(DOLLARS IN THOUSANDS)

	LIMITED PARTNER	GENERAL PARTNER	PARENT'S UNITS	ACCUM. OCI	TOTAL
Balances, December 31, 1999	$ 791,279	$ 8,074	$ (4,727)		$ 794,626
Net income	220,815	2,253			223,068
Leases paid by EPCO	10,537	107			10,644
Asset contributions by partners related to business acquisitions	55,241	564			55,805
Cash distributions to partners	(140,043)	(1,429)			(141,472)
Balances, December 31, 2000	937,829	9,569	(4,727)		942,671
Net income	242,246	2,472			244,718
Leases paid by EPCO	10,309	105			10,414
Asset contributions by partners related to business acquisitions	117,067	1,195			118,262
Cash distributions to partners	(165,357)	(1,687)			(167,044)
Treasury Units acquired by consolidated Trust			(18,003)		(18,003)
Treasury Units reissued by consolidated Trust			16,508		16,508
Gain on reissuance of Treasury Units by consolidated Trust	6,030	62			6,092
Cumulative transition adjustment recorded per SFAS No. 133				$ 42,190	42,190
Reclassification of cumulative transition adjustment to earnings				(42,190)	(42,190)
Balances, December 31, 2001	1,148,124	11,716	(6,222)	-	1,153,618
Net income	95,973	979			96,952
Leases paid by EPCO	9,033	92			9,125
Contributions from partners	180,665	1,844			182,509
Cash distributions to partners	(222,202)	(2,268)			(224,470)
Treasury Units acquired by consolidated Trust			(2,438)		(2,438)
Change in fair value of financial instruments recorded as cash flow hedges (see Note 16)				(3,560)	(3,560)
Balances, December 31, 2002	$ 1,211,593	$ 12,363	$ (8,660)	$ (3,560)	$ 1,211,736

See Notes to Consolidated Financial Statements

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ENTERPRISE PRODUCTS OPERATING L.P. (a Delaware limited partnership) was formed in April 1998 to acquire, own and operate all of the NGL processing and distribution assets of Enterprise Products Company ("EPCO"). We conduct substantially all of the business of our Limited Partner and parent, Enterprise Products Partners L.P. ("EPPLP"), which owns 98.9899% of our equity interests. Enterprise Products GP, LLC (the "General Partner") owns the remaining 1.0101% of our equity interests. Both the Limited Partner and General Partner are affiliates of EPCO. Our principal executive offices are located at 2727 North Loop West, Houston, Texas 77008-1038 and our telephone number is 713-880-6500. Unless the context requires otherwise, references to "we","us","our" or the "Company" are intended to mean Enterprise Products Operating L.P. and subsidiaries.

Prior to their consolidation, EPCO and its affiliate companies were controlled by members of a single family, who collectively owned at least 90% of each of the entities for all periods prior to the formation of the Company. As of April 30, 1998, the owners of all the affiliated companies exchanged their ownership interests for shares of EPCO. Accordingly, each of the affiliated companies became a wholly-owned subsidiary of EPCO or was merged into EPCO as of April 30, 1998. In accordance with generally accepted accounting principles, the consolidation of the affiliated companies with EPCO was accounted for as a reorganization of entities under common control in a manner similar to a pooling of interests.

On May 8, 1998, EPCO contributed all of its NGL assets to us (through our Limited and General Partners) and we assumed certain of EPCO's debt. As a result, we became the successor to the NGL operations of EPCO.

Effective July 27, 1998, our Limited Partner filed a registration statement pursuant to an initial public offering ("IPO") of 24,000,000 Common Units. The Common Units sold for $11 per unit. As a result, our Limited Partner contributed the proceeds of its IPO of approximately $243.3 million net of underwriting commissions and offering costs to the Company.

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 the Company 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 other than a temporary decline. The Company considers events affecting its equity method investments such as if they had continuing operating losses or significant and long-term changes in their industry conditions as examples of indicators of potential impairment. 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 for 2002, 2001 and 2000.

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 results of consolidated operations.

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 presented in the tabulations within the notes to our financial statements are stated in thousands of dollars, unless otherwise indicated.

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, 2002 were not significant to the consolidated financial statements. Costs of environmental compliance and monitoring aggregated $1.7 million, $1.3 million and $1.3 million for the years ended December 31, 2002, 2001 and 2000, 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 investments in Promix, Dixie, Neptune, La Porte and Nemo. The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. 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.

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 the Company. 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. 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 (as amended and interpreted) 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.

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. We have not recognized any impairment losses for any of the periods presented.

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 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 adopted SFAS 144 on January 1, 2002, and there have been no events or circumstances indicating that the carrying value of any of our assets may not be recoverable.

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 the Company. We generally classify improvements and major renewals of existing assets as sustaining capital expenditures and all other capital spending (on existing and new assets) as expansion capital expenditures.

PROVISION FOR INCOME TAXES is only applicable to the tax obligation of our Seminole pipeline business, which is a corporation and the only entity subject to income taxes in the consolidated group. The income tax provision relates solely to Seminole's earnings before income taxes for the five month period ended December 31, 2002. Deferred income tax assets and liabilities for Seminole are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes (see Note 11).

In and of itself, our partnership structure is not subject to federal income taxes. Accordingly, our owners are individually responsible for the taxes on their allocable share of our consolidated taxable income.

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, 2002 and 2001, cash and cash equivalents includes $8.8 million and $5.8 million of restricted cash related to these requirements, respectively.

REVENUE is recognized by our five reportable business segments 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. For additional information regarding our revenue recognition process, please see Note 2.

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 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 $21.2 million and $20.6 million at December 31, 2002 and 2001, respectively.

UNIT OPTION PLAN ACCOUNTING for reimbursement to EPCO under its 1998 Plan is accounted for by applying APB Opinion No. 25, "Accounting for Stock Issued to Employees," in accounting for equity-based awards granted to EPCO's employees whereby no compensation expense is recorded related to the options granted when the exercise price equals the market price of the underlying equity issue on the date of grant. See Note 13 for the pro forma effect on our net income, as if compensation expense had been determined based on the Black-Scholes option pricing model value at the grant date for equity-based awards consistent with the provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." No compensation expense was recorded during the years ended December 31, 2002, 2001 and 2000, since the equity-based awards were granted at exercise prices equal to the market prices at the date of grant.

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. REVENUE RECOGNITION

The following summarizes our revenue recognition process by business segment:

Pipelines segment revenues. In our Pipelines segment, 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 Federal Energy Regulatory Commission ("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.

Fractionation segment revenues. In our Fractionation segment, we enter into NGL fractionation, isomerization and propylene fractionation tolling arrangements, NGL fractionation in-kind 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, an in-kind tolling arrangement is utilized. An in-kind 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. Fractionation revenue is recognized and recorded on a monthly basis for transfers of "in-kind" retained NGL products to the NGL working inventory maintained within our Processing 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 Processing 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.

Processing segment revenues. As part of our Processing business, we have entered into a significant 20-year natural gas processing agreement with Shell (the "Shell Processing Agreement"), whereby we have the right to process Shell's current and future natural gas production (including deepwater developments) from the Gulf of Mexico within the state and federal waters off Texas, Louisiana, Mississippi, Alabama and Florida. In addition to the Shell Processing Agreement, we have contracts to process natural gas for other customers.

Under these natural gas processing contracts, the fee for our natural gas processing services is based upon contractual terms with Shell or other third parties and may be specified as either a cash fee or the retention of a percentage of the NGLs extracted from the natural gas stream. 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 Shell or other third parties (i.e., delivery has taken place).

If the natural gas processing contract stipulates that we retain a percentage of the extracted NGLs as payment for our services, revenue is recognized and recorded when the extracted NGLs are delivered out of our inventory and sold to customers on sales contracts. Our NGL marketing activities within this segment also use product sales contracts to sell and deliver out of inventory the NGLs transferred to it as a result of the Fractionation segment's in-kind 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 differing delivery locations.

Octane Enhancement segment revenues. The Octane Enhancement segment consists of our equity 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. Gross operating margin for this segment consists of our equity earnings from BEF, which in turn is dependent upon is BEF's general revenue recognition policy. 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.

Other segment revenues. Revenues shown for our Other segment are primarily derived from fee-based marketing services. 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.

Use of estimates in our revenue recognition process. The revenues that we record are not materially based on estimates. We believe the assumptions underlying any revenue estimates that we might use will not prove to be significantly different from actual amounts due to the routine nature of these estimates.

3. RECENTLY ISSUED ACCOUNTING STANDARDS

We adopted SFAS No. 142, "Goodwill and Other Intangible Assets", on January 1, 2002. This standard establishes accounting standards for all goodwill and other intangible assets recognized in our consolidated balance sheet. In addition, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" on January 1, 2002. This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. For information regarding our goodwill and intangible assets see Note 8. For information regarding our accounting policy for long-lived assets, please see Note 1.

We adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," on January 1, 2003. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation ("ARO") and the associated asset retirement cost. An ARO exists when a company determines that it has a clearly defined legal obligation upon retirement of a long-lived asset or any component part thereof and that the legal obligation will lead to the future payment of funds to a third party upon retirement of the asset. In general, legal obligations underlying AROs result from enacted laws and regulations or from contractual provisions related to long-lived assets. AROs can also arise through the normal course of operating a long-lived fixed asset.

An ARO liability will be recorded on the balance sheet if a reasonable estimate of fair value of the obligation can be made. Our estimate of fair value for each ARO is primarily dependent upon a clearly defined plan of retirement (dates, methods, etc.) and costs associated with the retirement activity. If a reasonable estimate cannot be made (i.e., no current or required plans for retirement of the asset, etc.), footnote disclosure is required but the ARO is not recorded until a reasonable estimate can be made. Any earnings impact resulting from the recognition of an ARO upon adoption of SFAS No. 143 should be reflected as the cumulative effect of a change in accounting principle.

Upon adoption of SFAS No. 143, we reviewed our long-lived assets for ARO's by segment. We identified, but have not recognized, ARO liabilities in several operational areas. These include ARO liabilities related to easements over property not currently owned by us. Our rights to the easements are renewable and only require retirement action upon nonrenewal of the easement agreements. We currently plan to renew all such easement agreements and use these properties indefinitely. Therefore, the ARO liability is not estimable for such easements. If we decide not to renew these agreements, an ARO liability would be recorded at that time.

ARO liabilities related to statutory regulatory requirements for abandonment or retirement of certain currently operated facilities were also identified. 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 occurred.

Certain Gulf of Mexico natural gas pipelines, in which we have an equity interest, have identified ARO's relating to regulatory requirements. There is no current intention to abandon or retire these pipelines. If these pipelines were abandoned or retired, an ARO liability would then be disclosed.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." This standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operations, plant closing, or other exit or disposal activity. Previous accounting guidance was provided by EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 replaces Issue 94-3. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002. We adopted this statement on January 1, 2003 and determined that it had no material impact on our financial statements.

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements from Guarantees, Including Indirect Guarantees of Indebtedness of Others". 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. The initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements in this interpretation are applicable for financial statements of interim or annual periods after December 15, 2002. See Note 9 for the disclosure of Parent-Subsidiary guarantor relationships.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure," which 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 in both annual and interim financial statements. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002, and financial reports containing condensed financial statements for interim periods beginning after December 15, 2002. EPCO has stock-based employee compensation plans for which we have a funding commitment for certain employees, see Note 13. We do not believe that the adoption of this statement will have a material effect on our financial statements.

4. BUSINESS ACQUISITIONS

ACQUISITION OF MID-AMERICA AND SEMINOLE IN JULY 2002

On July 31, 2002, we acquired equity interests in affiliates of Williams, which in turn, own controlling interests in Mid-America Pipeline Company, LLC ("Mid-America," formerly Mid-America Pipeline Company) and Seminole Pipeline Company ("Seminole"). The purchase price of the acquisitions was approximately $1.2 billion. The acquisition of Mid-America and Seminole significantly enhances our existing asset base by:

- accessing NGL-rich natural gas production in major North American natural gas producing regions;
- expanding our integrated natural gas and NGL network;
- providing access to new end markets for NGL products; and
- increasing our gross margins from fee-based businesses.

In addition to our current strategic position in the Gulf of Mexico, we now have access to major supply basins throughout North America, including the Rocky Mountain Overthrust, the San Juan and Permian basins, the Mid-Continent region and, through third-party pipeline connections, north into Canada's Western Sedimentary basin. The combination of these assets with our existing assets also creates a significant link between Mont Belvieu, Texas and Conway, Kansas, the two largest NGL hubs in the United States. They also provide additional access to new end markets for NGL products.

The acquisitions include a 98% ownership interest in Mapletree, LLC, which is the sole owner of Mid-America and certain propane terminals and storage facilities. Mid-America owns a regulated 7,226-mile major NGL pipeline system (the "Mid-America 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 Rocky Mountain system 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, through third-party pipeline connections, NGL supplies from Canada's Western Sedimentary basin. The Conway South system 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 acquired a 98% ownership interest in E-Oaktree, LLC, owner of an 80% equity interest in Seminole. Seminole owns a regulated 1,281-mile pipeline (the "Seminole Pipeline System") 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 primary source of throughput for the Seminole system are those volumes originating from the Mid-America system.

The initial funding for these acquisitions was accomplished by entering into a $1.2 billion 364-day credit facility (the "364-Day Term Loan"; see Note 9 for a description of this debt). This temporary credit facility was extinguished in February 2003 when we completed our plans for the permanent financing of these acquisitions (see our discussion of subsequent events in Note 19). These acquisitions did not require any material governmental approvals.

ACQUISITION OF DIAMOND-KOCH PROPYLENE FRACTIONATION BUSINESS IN FEBRUARY 2002

In February 2002, we purchased various propylene fractionation assets and certain inventories of refinery grade propylene, propane, and polymer grade propylene from Diamond-Koch. These include a 66.7% interest in a polymer grade propylene fractionation facility located in Mont Belvieu, Texas (the "Splitter III" facility), a 50% interest in an entity which owns a polymer grade propylene export terminal located on the Houston Ship Channel in La Porte, Texas, and varying interests in several supporting distribution pipelines and related equipment. Splitter III has the capacity to produce approximately 41 MBPD of polymer grade propylene. These assets are part of our Mont Belvieu propylene fractionation operations, which is part of the Fractionation segment. The purchase price of $239.0 million was funded by a drawdown on our Multi-Year and 364-Day Revolving Credit facilities.

ACQUISITION OF DIAMOND-KOCH STORAGE BUSINESS IN JANUARY 2002

In January 2002, we purchased various hydrocarbon storage assets from Diamond-Koch. The storage facility consists of 25 operational salt dome storage caverns with a useable capacity of 64 million barrels, local distribution pipelines and related equipment. The facilities provide storage services for mixed natural gas liquids, ethane, propane, butanes, natural gasoline and olefins (such as ethylene), polymer grade propylene, chemical grade propylene and refinery grade propylene. The facilities are located in Mont Belvieu, Texas and serve the largest petrochemical and refinery complex in the United States. These assets are part of our Mont Belvieu storage operations, which is part of the Pipelines segment. The purchase price of $129.6 million was funded by utilizing cash on hand.

OTHER MINOR ACQUISITIONS COMPLETED DURING 2002

We completed the purchase of an additional interest in our Mont Belvieu NGL fractionator from ChevronTexaco, the acquisition of a gas processing plant and NGL fractionator in Louisiana from Western Resources and certain NGL terminal assets from CornerStone during 2002. Due to the immaterial nature of each of these acquisitions, our discussion of each is limited to the following:

Acquisition of ChevronTexaco's interest in our Mont Belvieu NGL fractionator. Effective June 2002, we finalized the acquisition of a 12.5% undivided ownership interest in our Mont Belvieu, Texas NGL fractionator from an affiliate of ChevronTexaco. The purchase price of approximately $8.1 million was paid in May 2002. As a result of this transaction, our ownership interest in the Mont Belvieu NGL fractionator increased to 75.0% from 62.5%.

Acquisition of gas processing and NGL fractionator assets from Western Gas Resources, Inc. Effective June 2002, we acquired a 160 MMcf/d natural gas processing plant, a 14.2 MBPD NGL fractionator and supporting assets (including contracts) from Western Gas Resources, Inc. for approximately $32.6 million. The "Toca-Western" facilities are located in St. Bernard Parish, Louisiana near our existing Toca natural gas processing plant.

Acquisition of NGL terminals from CornerStone. In November 2002, we purchased four NGL terminals and existing propane inventories from an affiliate of CornerStone for approximately $11.5 million. The terminals are located in Bakersfield and Rocklin, California; Reno, Nevada and Albertville, Alabama. In addition, we acquired storage facilities related to these terminals with a capacity of 0.1 million barrels. These terminals will support our NGL marketing activities and fee-based marketing services.

ACADIAN GAS POST-CLOSING ADJUSTMENTS COMPLETED IN APRIL 2002

In April 2002, we finalized the post-closing purchase price adjustment associated with our April 2001 acquisition of Acadian Gas. Acadian Gas was acquired from an affiliate of Shell and is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. As a result, we paid Shell $18.0 million for various working capital items, the majority of which were related to natural gas inventories.

ALLOCATION OF AMOUNTS PAID DURING 2002

The acquisitions and post-closing adjustments described previously were accounted for under the purchase method of accounting and, accordingly, the cost of each has been allocated to the assets acquired and liabilities assumed based on their estimated fair values as follows:

	D-K STORAGE	D-K PROPYLENE FRACTIONATION	MID-AMERICA AND SEMINOLE	OTHER	TOTAL
Accounts and notes receivable			$ 11,777	$ (120)	$ 11,657
Accounts receivable - affiliates			7,799		7,799
Inventories		$ 4,994	10,776	4,403	20,173
Prepaids and other current assets	$ 890	3,148	9,204	416	13,658
Property, plant and equipment	120,571	96,772	1,265,264	24,636	1,507,243
Investments in unconsolidated affiliates		7,550			7,550
Intangible assets	8,127	53,000		31,229	92,356
Goodwill		73,691			73,691
Deferred tax asset			17,307		17,307
Other assets			2,699		2,699
Accounts payable - affiliates			(7,799)		(7,799)
Accrued expenses			(5,529)		(5,529)
Accrued interest			(667)		(667)
Other current liabilities		(107)	(12,226)	8,581	(3,752)
Long-term debt			(60,000)		(60,000)
Other long-term liabilities			(90)		(90)
Minority interest			(55,569)		(55,569)
Total purchase price	$ 129,588	$ 239,048	$1,182,946	$ 69,145	$1,620,727

The fair value estimates for both Diamond-Koch transactions; Mid-America and Seminole; the Toca-Western and CornerStone acquisitions were developed by independent appraisers using recognized business valuation techniques. The Mid-America, Seminole and CornerStone allocations are preliminary pending completion of a final review of these businesses which is expected to be completed during the first quarter of 2003. The purchase price allocations related to the Acadian Gas post-closing adjustment and the acquisition of ChevronTexaco's interest in our Mont Belvieu NGL fractionator are based on previously issued fair value reports.

The purchase price paid for the propylene fractionation business resulted in goodwill of $73.7 million. The goodwill primarily represents the value management has attached to future earnings improvements and to the strategic location of the assets. Earnings from the propylene business are expected to improve substantially from the last few years with the years 2005 and 2006 projected to be peak years in the petrochemical business cycle based on industry forecasts. The propylene fractionation assets are located in Mont Belvieu, Texas on the Gulf Coast, the largest natural gas liquids and petrochemical marketplace in the U.S. The assets have access to substantial supply from major Gulf Coast and central U.S. producers of refinery grade propylene. The polymer grade products produced at the facility have competitive advantages because of distribution direct to customers via affiliated pipelines and through an affiliated export facility. For additional information regarding our goodwill, see Note 8.

COMBINED PRO FORMA EFFECT OF MID-AMERICA, SEMINOLE, DIAMOND-KOCH AND ACADIAN GAS BUSINESS ACQUISITIONS

The following table presents unaudited pro forma financial information incorporating the historical (pre-acquisition) financial results of the following acquired businesses:

- D-K storage (acquired January 1, 2002) and propylene fractionation (acquired February 1, 2002);
- Mid-America and Seminole (both acquired July 31, 2002); and
- Acadian Gas (acquired April 1, 2001).

Our historical Statements of Consolidated Operations and Comprehensive Income reflect the operations of each acquired business since their respective acquisition dates.

The following pro forma information has been prepared as if the acquisitions had been completed on January 1 of the respective periods presented as opposed to the actual dates that these acquisitions occurred. The pro forma information is based upon data currently available to and certain estimates and assumptions made by management. As a result, this information is not necessarily indicative of our financial results had the transactions actually occurred on these dates. Likewise, the unaudited pro forma information is not necessarily indicative of our future financial results.

	FOR YEAR ENDED DECEMBER 31,	
	2002	2001
PRO FORMA EARNINGS DATA		
Revenues	$ 3,784,286	$ 3,952,896
Operating income	$ 275,498	$ 383,865
Net income	$ 132,334	$ 254,968
PRO FORMA EARNINGS ALLOCATION		
To Limited Partner	$ 130,997	$ 252,393
To General Partner	$ 1,337	$ 2,575

Pro forma net income for each year includes (among other pro forma adjustments) the impact of interest expense associated with the 364-Day Term Loan we used to fund the Mid-America and Seminole acquisitions. The pro forma results for 2001 assume that the initial $1.2 billion borrowed under this facility was outstanding during the entire year. The pro forma results for 2002 reflect our actual repayment of a portion of this debt using contributions related to our Limited Partner's October 2002 equity offering and our General Partner's related contribution. The pro forma earnings data do not reflect contributions from our Limited Partner's January 2003 equity offering nor our January 2003 issuance of Senior Notes C or February 2003 issuance of Senior Notes D. The proceeds from these equity and debt offerings were used to fully repay the 364-Day Term Loan by the end of February 2003. For additional information regarding these subsequent events, see Note 19.

5. INVENTORIES

Our inventories were as follows at the dates indicated:

	DECEMBER 31,	
	2002	2001
Working inventory	$ 131,769	$ 29,393
Forward-sales inventory	35,600	33,549
Inventory	$ 167,369	$ 62,942

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. 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 2), these volumes are valued at market-related prices during the month in which they are acquired. Like the third-party purchases described above, we inventory the various ancillary costs such as freight-in and other handling and processing amounts associated with owned volumes obtained through our in-kind and similar contracts.

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

- NGL inventory write-downs are recorded as a cost of the Processing segment's NGL marketing activities;

- Natural gas inventory write downs are recorded as a cost of the Pipeline segment's Acadian Gas operations; and

- Petrochemical inventory write downs are recorded as a cost of the Fractionation segment's propylene fractionation business.

For the years ended December 31, 2002, 2001 and 2000, we recognized LCM adjustments of approximately $6.3 million, $40.7 million and $6.9 million, respectively. The majority of these write-downs were taken against NGL inventories. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated (or in some cases, offset). See Note 16 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, 2002	DECEMBER 31, 2001
Plants and pipelines	5-35	$ 2,860,180	$ 1,398,843
Underground and other storage facilities	5-35	283,114	127,900
Transportation equipment	3-35	5,118	3,736
Land		23,817	15,517
Construction in progress		49,586	98,844
Total		3,221,815	1,644,840
Less accumulated depreciation		410,976	338,050
Property, plant and equipment, net		$ 2,810,839	$ 1,306,790

Depreciation expense for the years ended December 31, 2002, 2001 and 2000 was $72.5 million, $43.4 million and $33.3 million, respectively.

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 method. The investments in and advances to these unconsolidated affiliates are grouped according to the operating segment to which they relate. For a general discussion of our business segments, see Note 18. The following table shows our investments in and advances to unconsolidated affiliates at:

	OWNERSHIP PERCENTAGE	DECEMBER 31, 2002	DECEMBER 31, 2001
Accounted for on equity basis:			
Fractionation:			
BRF	32.25%	$ 28,293	$ 29,417
BRPC	30.00%	17,616	18,841
Promix	33.33%	41,643	45,071
La Porte	50.00%	5,737	
OTC	50.00%	2,178	
Pipeline:			
EPIK	50.00%	11,114	14,280
Wilprise	37.35%	8,566	8,834
Tri-States	33.33%	25,552	26,734
Belle Rose	41.67%	11,057	11,624
Dixie	19.88%	36,660	37,558
Starfish	50.00%	28,512	25,352
Neptune	25.67%	77,365	76,880
Nemo	33.92%	12,423	12,189
Evangeline	49.50%	2,383	2,578
Octane Enhancement:			
BEF	33.33%	54,894	55,843
Accounted for on cost basis:			
Processing:			
VESCO	13.10%	33,000	33,000
Total		$ 396,993	$ 398,201

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

	OWNERSHIP PERCENTAGE	FOR YEAR ENDED DECEMBER 31, 2002	2001	2000
Fractionation:				
BRF	32.25%	$ 2,427	$ 1,583	$ 1,369
BRPC	30.00%	997	1,161	(284)
Promix	33.33%	3,936	4,201	5,306
La Porte	50.00%	(559)		
OTC	50.00%	378		
Pipelines:				
EPIK	50.00%	4,688	345	3,273
Wilprise	37.35%	948	472	497
Tri-States	33.33%	1,959	1,565	2,499
Belle Rose	41.67%	203	103	301
Dixie	19.88%	1,231	2,092	751
Starfish	50.00%	7,346	4,122	
Ocean Breeze	25.67%	-	32	
Neptune	25.67%	2,111	4,081	
Nemo	33.92%	1,077	75	
Evangeline	49.50%	(58)	(145)	
Octane Enhancement:				
BEF	33.33%	8,569	5,671	10,407
Total		$ 35,253	$ 25,358	$ 24,119

At December 31, 2002, our share of accumulated earnings of equity method unconsolidated affiliates that had not been remitted to us was approximately $15.4 million. In addition, our initial investment in Promix, La Porte, Dixie, Neptune and Nemo 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, 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 goodwill inherent in Dixie's excess cost is subject to periodic impairment testing; therefore, it is not amortized. The following table summarizes our excess cost information:

	INITIAL EXCESS COST	UNAMORTIZED BALANCE AT DECEMBER 31, 2002	UNAMORTIZED BALANCE AT DECEMBER 31, 2001	AMORTIZATION CHARGED AGAINST EQUITY EARNINGS DURING 2002	AMORTIZATION PERIOD
Fractionation segment:					
Promix	$ 7,955	$ 6,596	$ 7,083	$ 398	20 years
La Porte	873	833	n/a	40	35 years
Pipelines segment:					
Dixie					
Attributable to pipeline assets	28,448	26,074	26,887	813	35 years
Goodwill	9,246	8,827	8,827	n/a	n/a
Neptune	12,768	12,039	12,404	365	35 years
Nemo	727	697	718	21	35 years

As used in the following condensed financial data tables, gross operating margin represents operating income before applicable depreciation and amortization expense and selling, general and administrative costs. Gross operating margin is an important measure of the profitability of assets owned by our unconsolidated affiliates. We regularly evaluate our consolidated operations on the same basis. Operating income represents earnings before non-operating income and expense items such interest expense and interest income. The equity earnings we record from these investments represent our share of the net income or loss of each.

FRACTIONATION SEGMENT:

At December 31, 2002, the Fractionation segment included the following unconsolidated affiliates accounted for using the equity method:

- Baton Rouge Fractionators LLC ("BRF") - an approximate 32.25% interest in an NGL fractionator located in southeastern Louisiana.
- Baton Rouge Propylene Concentrator, LLC ("BRPC") - a 30.0% interest in a propylene fractionator located in southeastern Louisiana.
- K/D/S Promix LLC ("Promix") - a 33.33% interest in an NGL fractionator and related storage and pipeline assets located in south Louisiana.
- 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 are precluded from consolidating its financial statements with our financial statements.
- Olefins Terminal Corporation ("OTC") - a 50% interest in a polymer grade propylene export facility located in Seabrook, Texas. As with La Porte, we do not exercise management control over OTC and are precluded from consolidating its financial statements with our financial statements.

The combined balance sheet information for the last two years and results of operations data for the last three years of the Fractionation segment's equity method investments are summarized below.

	AS OF OR FOR THE YEAR ENDED DECEMBER 31,		
	2002	2001	2000
BALANCE SHEET DATA:			
Current assets	$ 23,496	$ 27,424	
Property, plant and equipment, net	250,096	251,519	
Total assets	$ 273,592	$ 278,943	
Current liabilities	$ 11,229	$ 9,950	
Other liabilities	6,800		
Combined equity	255,563	268,993	
Total liabilities and combined equity	$ 273,592	$ 278,943	
INCOME STATEMENT DATA:			
Revenues	$ 78,350	$ 76,480	$ 71,287
Gross operating margin	40,215	36,321	33,240
Operating income	23,464	22,396	19,997
Net income	23,399	22,738	20,661

PIPELINES SEGMENT:

At December 31, 2002, our Pipelines operating segment included the following unconsolidated affiliates accounted for using the equity method:

- EPIK Terminalling L.P. and EPIK Gas Liquids, LLC (collectively, "EPIK") - a 50% aggregate interest in an NGL export terminal located in southeast Texas. In March 2003, we purchased the remaining ownership interests in EPIK for $19 million plus certain post-closing purchase price adjustments, at which time EPIK became a consolidated subsidiary of ours (see Note 19). Prior to our purchase of the remaining interests, we did not exercise management control over EPIK and were precluded from consolidating its financial statements with our financial statements.
- Wilprise Pipeline Company, LLC ("Wilprise") - a 37.35% interest in an NGL pipeline system located in southeastern Louisiana.
- Tri-States NGL Pipeline LLC ("Tri-States") - an aggregate 33.33% interest in an NGL pipeline system located in Louisiana, Mississippi and Alabama.
- Belle Rose NGL Pipeline LLC ("Belle Rose") - a 41.67% interest in an NGL pipeline system located in south Louisiana.
- Dixie Pipeline Company ("Dixie") - an aggregate 19.88% interest in a 1,301-mile propane pipeline and associated facilities extending from Mont Belvieu, Texas to North Carolina.
- Starfish Pipeline Company LLC ("Starfish") - a 50% interest in a natural gas gathering system 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 LLC ("Neptune") - a 25.67% interest in the natural gas gathering and transmission 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 33.92% interest in a natural gas gathering system located in the Gulf of Mexico offshore Louisiana that became operational in August 2001.
- 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.

The combined balance sheet information for the last two years and results of operations data for the last three years of the Pipelines segment's equity method investments are summarized below:

	AS OF OR FOR THE YEAR ENDED DECEMBER 31,		
	2002	2001	2000
BALANCE SHEET DATA:			
Current assets	$ 76,930	$ 68,325	
Property, plant and equipment, net	510,483	515,327	
Other assets	47,501	50,265	
Total assets	$ 634,914	$ 633,917	
Current liabilities	$ 60,484	$ 62,347	
Other liabilities	56,230	57,965	
Combined equity	518,200	513,605	
Total liabilities and combined equity	$ 634,914	$ 633,917	
INCOME STATEMENT DATA:			
Revenues	$ 303,567	$ 305,404	$ 96,270
Gross operating margin	112,455	98,682	51,414
Operating income	65,855	54,459	41,757
Net income	56,736	41,015	31,241

OCTANE ENHANCEMENT SEGMENT:

At December 31, 2002, the Octane Enhancement segment included our 33.33% interest in Belvieu Environmental Fuels ("BEF"), a facility located in southeast Texas that produces motor gasoline additives to enhance octane. The BEF facility currently produces MTBE. The production of MTBE is driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990 and other legislation and as an additive to increase octane in motor gasoline. Any changes to these oxygenated fuel programs that enable localities to elect to not participate in these programs, lessen the requirements for oxygenates or favor the use of non-isobutane based oxygenated fuels will reduce the demand for MTBE and could have an adverse effect on our results of operations.

In recent years, MTBE has been detected in municipal and private water supplies resulting in various legal actions. BEF has not been named in any MTBE legal action to date. In light of these legal and regulatory developments, we and the other two partners of BEF are actively compiling a contingency plan for the BEF facility should MTBE be banned. We are currently evaluating a possible conversion of the facility from MTBE production to alkylate production. In addition to MTBE's value in reducing air pollution, it is a significant source of octane in the U.S. motor gasoline pool. Octane is a critical component of motor gasoline. Therefore, we believe that if MTBE usage is banned or significantly curtailed, the motor gasoline industry would need a substitute additive to maintain octane levels in gasoline and that alkylate would be an economic and effective substitute. We are currently conducting a detailed engineering study that is expected to be completed by the end of 2003, at which time we expect a more definitive conversion cost estimate will be available. The cost to convert the facility will depend on the type of alkylate process chosen and level of alkylate production desired by the partnership.

Balance sheet information for the last two years and results of operations data for the last three years for BEF are summarized below:

	AS OF OR FOR THE YEAR ENDED DECEMBER 31,		
	2002	2001	2000
BALANCE SHEET DATA:			
Current assets	$ 37,237	$ 29,301	
Property, plant and equipment, net	129,019	140,009	
Other assets	9,050	10,067	
Total assets	$ 175,306	$ 179,377	
Current liabilities	$ 16,787	$ 13,352	
Other liabilities	4,017	3,438	
Partners' equity	154,502	162,587	
Total liabilities and partners' equity	$ 175,306	$ 179,377	
INCOME STATEMENT DATA:			
Revenues	$ 229,358	$ 213,734	$ 258,180
Gross operating margin	71,537	28,701	43,328
Operating income	25,461	15,984	30,529
Net income	25,707	17,014	31,220

PROCESSING SEGMENT:

At December 31, 2002, 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.

8. INTANGIBLE ASSETS AND GOODWILL

INTANGIBLE ASSETS

The following table summarizes our intangible assets at December 31, 2002 and 2001:

		AT DECEMBER 31, 2002		AT DECEMBER 31, 2001	
	GROSS VALUE	ACCUM. AMORT.	CARRYING VALUE	ACCUM. AMORT.	CARRYING VALUE
Shell natural gas processing agreement	$ 206,331	$ (23,015)	$ 183,201	$ (11,962)	$ 194,369
Mont Belvieu Storage II contracts	8,127	(232)	7,895		
Mont Belvieu Splitter III contracts	53,000	(1,388)	51,612		
Toca-Western natural gas processing contracts	11,096	(326)	10,861		
Toca-Western NGL fractionation contracts	20,041	(585)	19,457		
Venice contracts (a)	4,639		4,635		
MBA acquisition goodwill (b)	8,979			(1,122)	7,857
Total	$ 312,213	$ (25,546)	$ 277,661	$ (13,084)	$ 202,226

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(a) Amortization will commence when contracted-volumes begin to be processed in 2003.

(b) Amount reclassified to Goodwill on January 1, 2002 per transition provisions of SFAS 142.

At December 31, 2002, our intangible assets consisted of:

- the Shell natural gas processing agreement that we acquired as part of the TNGL acquisition in August 1999;
- certain storage and propylene fractionation contracts we acquired in connection with the Diamond-Koch acquisitions in January and February 2002;
- certain natural gas processing and NGL fractionation contracts we acquired in connection with the Toca-Western acquisition in June 2002; and
- certain NGL-related contracts (the "Venice contracts") we acquired during the third quarter of 2002.

The following table shows amortization expense associated with our intangible assets for the years ended December 31, 2002, 2001 and 2000:

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Shell natural gas processing agreement	$ 11,054	$ 7,260	$ 3,576
Mont Belvieu Storage II contracts	232		
Mont Belvieu Splitter III contracts	1,388		
Toca-Western natural gas processing contracts	326		
Toca-Western NGL fractionation contracts	585		
MBA acquisition goodwill (a)		449	453
Total	$ 13,585	$ 7,709	$ 4,029

(a) Our MBA acquisition goodwill is no longer subject to amortization under SFAS 142 guidelines.

The value of the Shell natural gas processing agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term (currently $11.1 million annually from 2002 through 2019). The values of the propylene fractionation and storage contracts acquired from Diamond-Koch are being amortized on a straight-line basis over the economic life of the assets to which they relate, which is currently estimated at 35 years. The Toca-Western natural gas processing contracts are being amortized over the expected 20-year remaining life of the natural gas supplies supporting these contracts. The value of the Toca-Western NGL fractionation contracts is being amortized over the expected 20-year remaining life of the assets to which they relate. The value of the Venice contracts will be amortized over 14 years beginning in the third quarter of 2003.

For 2003, amortization expense attributable to these intangible assets is currently estimated at $14.5 million. Based on information currently available, we expect that amortization expense relating to existing intangibles will increase to $14.7 million during each of the years 2004 through 2007.

GOODWILL

At December 31, 2002, the value of goodwill was $81.5 million. Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired and is comprised of the following (values as of December 31, 2002):

- $73.6 million associated with the purchase of propylene fractionation assets from Diamond-Koch in February 2002; and,
- $7.9 million related to the July 1999 purchase of an additional ownership interest in MBA, which in turn owned an interest in our Mont Belvieu NGL fractionation facility.

Our goodwill amounts are classified as part of the Fractionation segment since they are related to assets recorded in this operating segment. At December 31, 2001, the goodwill associated with the MBA acquisition was recorded as part of our intangible assets.

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 adoption of SFAS No. 142, the only goodwill amortization we recorded was that associated with the MBA acquisition from July 1999. Due to the immaterial nature of such amortization expense (approximately $0.4 million per year), the pro forma effect of not amortizing this goodwill in 2001 or 2000 would have had a negligible effect on our net income.

9. DEBT OBLIGATIONS

Our debt consisted of the following at:

	DECEMBER 31,	
	2002	2001
Borrowings under:		
364-Day Term Loan, variable rate, due July 2003	$ 1,022,000	
364-Day Revolving Credit facility, variable rate, due November 2004	99,000	
Multi-Year Revolving Credit facility, variable rate, due November 2005	225,000	
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	$ 350,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	450,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 2005	45,000	
Total principal amount	2,245,000	854,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,774	1,653
Less unamortized discount on:		
Senior Notes A	(81)	(117)
Senior Notes B	(230)	(258)
Less current maturities of debt	(15,000)	-
Long-term debt	$ 2,231,463	$ 855,278

The table above does not reflect the issuance of our $350 million principal amount Senior Notes C in January 2003 and $500 million principal amount Senior Notes D in February 2003 nor does it reflect the repayment of debt using contributions from our Limited Partner related to its January 2003 equity offering. We used a combination of proceeds from the issuance of our Senior Notes C and D and the Limited Partner's contribution related to its January 2003 equity offering to completely repay the 364-Day Term Loan by the end of February 2003 (see the section titled "General description of debt--364-Day Term Loan" within this note for additional information regarding the use of proceeds to extinguish this debt). For additional information regarding subsequent events affecting our debt balances, see Note 19.

As to the assets of our subsidiary, Seminole Pipeline Company, our $2.2 billion in senior indebtedness at December 31, 2002 is structurally subordinated and ranks junior in right of payment to the $45 million of indebtedness of Seminole Pipeline Company. 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, 2002 reflect the classification of such debt obligations at March 7, 2003.

LETTERS OF CREDIT

At December 31, 2002, we had a total of $75 million of standby letters of credit capacity under our Multi-Year Revolving Credit facility, of which $2.4 million was outstanding.

PARENT-SUBSIDIARY GUARANTOR RELATIONSHIPS

Enterprise Products Partners L.P. (the "MLP", on a stand-alone basis) acts as guarantor of certain of our debt obligations. These parent-subsidiary guaranty provisions exist under all of our debt obligations with the exception of the Seminole Notes. The Seminole Notes are unsecured obligations solely of Seminole Pipeline Company. If we were to default on any guaranteed debt obligation, the MLP would be responsible for full payment of that obligation.

GENERAL DESCRIPTION OF DEBT

The following is a summary of the significant aspects of our debt obligations at December 31, 2002.

364-Day Term Loan. We entered into a $1.2 billion senior unsecured 364-day term loan to fund the Mid-America and Seminole acquisitions in July 2002. We applied $178.8 million in cash contributions received from our Limited Partner related to its October 2002 equity offering to partially repay this loan. In addition, we used $252.8 million of the $258.9 million in cash contributions received from Limited Partner related to its 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 completely repay the 364-Day Term Loan by the end of February 2003 (see Note 19). Base variable interest rates under this facility generally bore interest at either (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent or (2) a Eurodollar rate. Whichever base interest rate we selected, the rate was increased by an appropriate applicable margin (as defined within the loan agreement). During 2002, the weighted-average interest rate charged was 3.10%, with the range of rates being between 4.88% and 2.88%. This facility contained various covenants similar to those of our revolving credit facilities. We were in compliance with these covenants at December 31, 2002.

364-Day Revolving Credit facility. In November 2000, we entered in a 364-Day revolving credit agreement. Currently, the stand-alone borrowing capacity under this credit facility is $230 million with the maturity date for any amount outstanding being November 2003. We have the option to convert any revolving credit balance outstanding at maturity to a one-year term loan (due November 2004) in accordance with the terms of the credit agreement. This credit facility is guaranteed by the MLP through an unsecured guarantee. In addition, our borrowings under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. We applied $60.0 million in proceeds from our February 2003 issuance of Senior Notes D to reduce the balance outstanding under this facility during 2003 (see Note 19).

As defined by the credit agreement, variable interest rates charged under this facility generally bear interest at either (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent 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. During 2002, the weighted-average interest rate charged for borrowings under this facility was 2.51%, with the range of rates being between 4.75% and 2.37%.

The 364-Day Revolving Credit facility 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 quarter. As defined within 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, 2002. The MLP has entered into an unsecured and unsubordinated guarantee of this debt. This debt is non-recourse to the General Partner.

Multi-Year Revolving Credit facility. In conjunction with the 364-Day Revolving Credit facility, we entered into a five-year revolving credit facility that includes a sublimit capacity of $75 million for standby letters of credit. Currently, the stand-alone borrowing capacity under this credit facility is $270 million. This credit facility is guaranteed by the MLP through an unsecured guarantee. In addition, our borrowings under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. The interest rates charged under this facility are determined in the same manner as that described under our 364-Day Revolving Credit facility. During 2002, the weighted-average interest rate charged for borrowings under this facility was 2.37%, with the range of rates being between 4.75% and 2.00%.

This facility contains various covenants similar to those of our 364-Day Revolving Credit facility. (please refer to our discussion regarding restrictive covenants of the "364-Day Revolving Credit facility" within this "General description of debt" section). We were in compliance with these covenants at December 31, 2002.

Senior Notes A and B. These fixed-rate notes are an unsecured obligation of ours and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. Both notes are guaranteed by the MLP through an unsecured and unsubordinated guarantee and are non-recourse to the General Partner. These notes were issued under an indenture containing certain covenants and are subject to a make-whole redemption right. 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, 2002.

MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, we entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). This loan is subject to a make-whole redemption right and is guaranteed by MLP through an unsecured and unsubordinated guarantee. The indenture agreement for this loan contains an acceleration clause whereby the outstanding principal and interest on the loan may become due and payable within 120 days if our credit ratings decline below a Baa3 rating by Moody's (currently Baa2) and below a BBB- rating by Standard and Poors (currently BBB). Under these circumstances, the trustee (as defined within the loan agreement) may, and if requested to do so by holders of at least 25% of the principal amount of the underlying bonds, accelerate the maturity of the MBFC Loan. Should this acceleration occur, the entire principal balance of the MBFC Loan and all related accrued and unpaid interest would become immediately due and payable. If such an event occurred, we would have the option of (1) to redeem the MBFC Loan or (2) to provide an alternate credit agreement to support our obligation under the MBFC Loan. We would have 120 days to exercise these options upon receiving notice of the decline in our credit ratings.

The MBFC Loan agreement contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility and restrictions regarding mergers. We were in compliance with these covenants at December 31, 2002.

Seminole Notes. As a result of our acquisition of 78.4% of Seminole in July 2002, we are required to consolidate its debt with our other debt obligations. At December 31, 2002, Seminole had $45 million in fixed-rate senior unsecured notes, of which $15 million is due annually each December through December 2005. The Seminole Notes contain various covenants, such as minimum net worth requirements and those restricting Seminole's ability to borrow additional funds. Seminole was in compliance with these covenants at December 31, 2002.

10. CAPITAL STRUCTURE

We are owned 98.9899% by our Limited Partner and 1.0101% by our General Partner. For purposes of maintaining partner capital accounts, our partnership agreement generally specifies that items of income or loss shall be allocated among the partners in accordance with their respective ownership percentages. Net losses are first allocated to the partners in accordance with their respective percentages to the extent that the allocations do not cause the Limited Partner to have a deficit balance in its capital account. Any net loss not allocated to the Limited Partner is allocated to the General Partner. Normal allocations of net income to percentage interests are done only, however, after giving effect to any priority income allocations to the General Partner in an amount equal to any aggregate net losses incurred by the General Partner for all previous years. For the years ended December 31, 2002, 2001 and 2000, the allocation of earnings has been based solely on the respective ownership interests of the partners with no priority income allocations being necessary.

Our partnership agreement requires that we distribute 100% of the "Available Cash" (as defined within the agreement) to the partners within 45 days following the end of each calendar quarter in accordance with their respective ownership interests. Our distributions to partners during the three years ended December 31, 2002, 2001 and 2000 were $224.5 million, $167.0 million and $141.5 million.

In connection with the TNGL acquisition completed during 1999, Shell received 6.0 million non-distribution bearing, convertible special partnership interests in our Limited Partner during each of 2001 and 2000. The value of the special partnership interests issued during 2001 was $117.1 million while the value of those issued during 2000 was $55.2 million. Both values were determined using present value techniques. The value of these special partnership interests increased the overall purchase price of the TNGL acquisition and was allocated to the

Shell natural gas processing agreement. The value of the Limited Partner's special partnership interests granted to Shell was accounted for as a non-cash contribution to us by our Limited Partner.

In October 2002, our Limited Partner completed an equity offering from which we received a cash contribution of $180.7 million. In connection with the Limited Partner's contribution, we also received $1.8 million from our General Partner to maintain its 1.0101% partnership interest in us. We applied these cash contributions to the partial repayment of our 364-Day Term Loan and for working capital and other expenses. See Note 9 for a description of our 364-Day Term Loan. In January 2003, our Limited Partner completed another equity offering from which we received a total cash contribution of $258.9 million, which includes our General Partner's related contribution of $2.6 million. Again, we applied these cash contributions to the partial repayment of the 364-Day Term Loan and for working capital and other expenses.

Parent's Units acquired and reissued by a consolidated trust. During the first quarter of 1999, we established a revocable grantor trust, the EPOLP 1999 Grantor Trust or 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 purchased $2.4 million and $18.0 million of our Limited Partner's Common Units during 2002 and 2001, respectively. In November 2001, the 1999 Trust sold 1,000,000 Common Units costing $16.5 million to EPCO for $22.6 million. The $6.1 million profit on the sale of these Common Units has been credited to each partner in accordance with their respective ownership interest.

Buy-Back Program. The 1999 Trust participates in a Buy-Back Program with our parent entity, Enterprise Products Partners L.P. , under which an aggregate 2,000,000 Common Units of our Limited Partner can be repurchased. The source of funds used by Enterprise Products Partners L.P. to repurchase its Common Units are special cash distributions from us. All of the Common Units purchased by the 1999 Trust during 2002 and 2001 were under this program. At December 31, 2002, 618,400 Common Units could potentially be repurchased under the Buy-Back Program, either by the 1999 Trust or by Enterprise Products Partners L.P.

11. PROVISION FOR INCOME TAXES

Provision for income taxes is only applicable to the tax obligation of our Seminole pipeline business, which is a corporation and the only entity subject to income taxes in the consolidated group. The following is a summary of the provision for income taxes for Seminole for the period August 1, 2002 through December 31, 2002:

Current:	
Federal tax benefit	($391)
State tax benefit	(55)
	(446)
Deferred:	
Federal	1,812
State	268
	2,080
Provision for Income Taxes	$1,634

The following is a reconciliation of the provision for income taxes at the federal statutory rate to the provision for income taxes:

Taxes computed by applying the federal statutory rate	$1,488
State income taxes (net of federal benefit)	138
Other	8
Provision for income taxes	$1,634

Significant components of deferred income tax assets and liabilities at December 31, 2002 are as follows:

Deferred tax assets:	
Property, plant and equipment	$15,846
Deferred tax liabilities:	
Other	(619)
Net deferred tax assets	$15,227

Based upon the periods in which taxable temporary differences are anticipated to reverse, we believe it is more likely than not that the Company will realize the benefits of these deductible differences. Accordingly, we believe that no valuation allowance is required for the deferred tax assets. However, the amount of the deferred tax asset considered realizable could be adjusted in the future if estimates of reversing taxable temporary differences are revised.

12. RELATED PARTY TRANSACTIONS

Relationship with EPCO and its affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates. EPCO is majority-owned and controlled by Dan L. Duncan, Chairman of the Board and a director of the General Partner. In addition, three other members of the Board of Directors (O.S. Andras, Randa D. Williams and Richard H. Bachmann) and the remaining executive and other officers of the General Partner are employees of EPCO. 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 and Subordinated Units held by EPCO. The remaining shares of EPCO capital stock are held primarily by trusts for the benefit of the members of Mr. Duncan's family, including Ms. Williams (a director of the General Partner). In addition, EPCO and Dan Duncan, LLC collectively own 70% of the General Partner, which in turn owns a combined 2% interest in us.

In addition, trust affiliates of EPCO (the 1998 Trust and 2000 Trust) owned 2,478,236 Common Units at December 31, 2002. Collectively, EPCO, Dan L. Duncan, the 1998 Trust and the 2000 Trust owned 61.4% of our limited partnership interests at December 31, 2002. We neither direct the actions of either 1998 Trust or the 2000 Trust nor exercise any measure of control over their actions. Accordingly, these two trusts are not consolidated with our businesses.

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.

EPCO 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 EPCO Agreement. Under the terms of the EPCO Agreement, EPCO agrees to:

- employ the personnel necessary to manage our business and affairs (through the 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 of formulas 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;
- indemnify us against any losses resulting from certain lawsuits; 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 lease payments associated with these assets.

Operating costs and expenses (as shown in the Statements of Consolidated Operations) treat the lease payments being made by EPCO as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded as a general contribution to the partnership. In addition, operating costs and expenses include compensation charges for EPCO's employees who operate our facilities.

Pursuant to the EPCO Agreement, we reimburse 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 who manage our business and affairs. Our reimbursement of EPCO's administrative personnel expense is capped (currently at $17.6 million annually). The General Partner, with the approval and consent of the Audit and Conflicts Committee, may agree to increases of such fee up to ten percent per year during the 10-year term of the EPCO Agreement. Any difference between the actual costs of this "pre-expansion" group of administrative personnel (including costs associated with equity-based awards granted to certain individuals within this group) and the fee we pay will be born solely by EPCO. The actual amounts incurred by EPCO did not materially exceed the capped amounts for any periods. We also reimburse EPCO for the compensation of 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.

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.

- EPCO is the operator of the facilities owned by BEF, of which we own 33.33%. In lieu of charging BEF for the actual cost of providing management services, EPCO charges BEF a management fee. EPCO charged BEF $0.6 million for such services during each of 2002, 2001 and 2000.
- EPCO is also operator of the facilities owned by EPIK, of which we now wholly own. Prior to February 2003, we owned only 50% of EPIK. In lieu of charging EPIK for the actual cost of management services, EPCO charges EPIK a management fee. During 2002, 2001 and 2000, EPCO charged EPIK $0.3 million, $0.2 million and $0.3 million, respectively, for such services.
- We have entered into an agreement with EPCO to provide trucking services to us for the loading and transportation of products.
- In the normal course of business, we also buy from and sell NGL products to EPCO's Canadian affiliate.

The following table summarizes our various related party transactions with EPCO for the years ended December 31, 2002, 2001 and 2000:

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
REVENUES FROM CONSOLIDATED OPERATIONS			
EPCO	$ 3,630	$ 5,439	$ 4,750
OPERATING COSTS AND EXPENSES			
EPCO	103,210	62,919	52,861
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES			
Base fees payable under EPCO Agreement	16,638	15,125	13,750
Other EPCO compensation reimbursement	7,566	4,824	1,930

Relationship with Shell

We have an extensive and ongoing commercial relationship with Shell as a partner, customer and vendor. Shell, through its subsidiary Shell US Gas & Power LLC, currently owns approximately 20.5% of our limited partnership interests and 30.0% of the General Partner. Currently, three members of the Board of Directors of the General Partner (J. A. Berget, J.R. Eagan, and A.Y. Noojin, III) are employees of Shell.

Shell is our single largest customer. During 2002, it accounted for 7.8% of our consolidated revenues. Our revenues from Shell reflect the sale of NGL and petrochemical products to them and the fees we charge them 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 (see below) and the purchase of NGL products from them. The following table shows our revenues and operating costs and expenses with Shell for the years ended December 31, 2002, 2001 and 2000:

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
REVENUES FROM CONSOLIDATED OPERATIONS			
Shell	$ 282,820	$ 333,333	$ 292,741
OPERATING COSTS AND EXPENSES			
Shell	531,712	705,440	736,655

The most significant contract affecting our natural gas processing business is the 20-year Shell processing agreement, which grants us the right to process Shell's current and future production from state and federal waters of the Gulf of Mexico on a keepwhole basis. This is a life of lease dedication, which may extend the agreement well beyond 20 years. Generally, this contract has the following rights and obligations:

- the exclusive right, but not the obligation, to process substantially all of Shell's Gulf of Mexico natural gas production; plus
- the exclusive right, but not the obligation, 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 plants from Shell's natural gas production from such leases; with
- the obligation to re-deliver to Shell the natural gas stream after the mixed NGL stream is extracted.

Under this contract, we are responsible for reimbursing Shell for the market value of the energy we extract from their natural gas stream in the course of performing natural gas processing services for them. Our reimbursement to Shell (which we record as an operating cost) is generally based upon the energy value of the fuel we consume and the NGLs we extract from their natural gas stream (in terms of its Btu content, a measure of heating value). In lieu of collecting a cash fee for our services under this contract, we take ownership of the NGLs we extract from their natural gas stream. These volumes (our "equity NGL production") become part our inventory held for sale. We derive a profit to the extent that the revenues from the ultimate sale and delivery to customers of these NGLs exceeds the costs of extraction and any other inventory costs such as fractionation fees.

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 three issues of Special Units granted to Shell in connection with this acquisition);
- the purchase of the Lou-Tex Propylene Pipeline System 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 the Gulf of Mexico natural gas pipelines we acquired from El Paso in 2001. 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 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 $2.2 million in letters of credit on behalf of Evangeline.
- We pay EPIK for export services to load product cargoes for our NGL and petrochemical marketing customers.
- We pay Dixie transportation fees for propane movements on their system initiated by our NGL marketing activities.
- We sell high purity isobutane to BEF as a feedstock and purchase certain of BEF's by-products. We also receive transportation fees for MTBE movements on our HSC pipeline and fractionation revenues for reprocessing mixed feedstock streams generated by BEF.
- 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.

The following table summarizes our related party transactions with unconsolidated affiliates for the years ended December 31, 2002, 2001 and 2000:

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
REVENUES			
Evangeline	$ 131,635	$ 117,283	
EPIK	259	297	$ 5,070
BEF	50,494	45,778	56,216
Promix	12,697	8,952	57
Other unconsolidated affiliates	1,182	1,374	645
OPERATING COSTS AND EXPENSES			
EPIK	19,788	7,438	17,600
Dixie	12,184	12,695	11,763
BEF	9,794	8,073	10,640
Promix	18,408	12,676	18,200
Other unconsolidated affiliates	482	193	

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.

13. UNIT OPTION PLAN ACCOUNTING

During 1998, EPCO adopted its 1998 Long-Term Incentive Plan (the "1998 Plan"). Under the 1998 Plan, non-qualified incentive options to purchase a fixed number of our Common Units (the "Units") of our Limited Partner 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 funds the purchase of the Units under the 1998 Plan at fair value in the open market.

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

Equity-based awards granted to certain key operations personnel. Under the EPCO Agreement (see Note 12), we reimburse EPCO for the compensation of all operations personnel it employs on our behalf. This includes the costs attributable to equity-based awards granted to these personnel. When these employees exercise Unit options, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price for the Units awarded to the employee. We may reimburse EPCO for these costs in a number of ways including furnishing cash or having our Limited Partner issue new Common Units. We record the expense associated with these awards in our operating costs and expenses as shown on our Statements of Consolidated Operations.

Equity-based awards granted to certain key expansion-related administrative and management employees. We also reimburse EPCO for the compensation of administrative and management 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 "expansion" group of EPCO employees. When these employees exercise Unit options, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price for the Units awarded to the employee. We may reimburse EPCO for these costs in a number of ways including furnishing cash or having our Limited Partner issue new Common Units. We record the expense associated with these awards in our selling, general and administrative costs as shown on our Statements of Consolidated Operations.

Equity-based awards granted to other key administrative and management employees. In addition, we reimburse 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 who manage our business and affairs. Our reimbursement for the cost of equity-based awards to this "pre-expansion" group of administrative EPCO employees is covered by the Administrative Services Fee we pay to EPCO. EPCO is responsible for the actual costs when the Unit options granted to these pre-expansion administrative employees are exercised. EPCO satisfies its equity-award obligations to these employees by arranging for Common Units of our Limited Partner to be purchased in the open market. We record the Administrative Service Fee paid to EPCO as a selling, general and administrative expense as shown on our Statements of Consolidated Operations.

Summary of 1998 Plan activity and amounts related to Employees who perform activities on our behalf

EPCO's 1998 Plan is used to issue Unit option awards to the three categories of employees discussed above. The information in the following table shows (i) Unit option activity for all operations and expansion-related administrative/management personnel and (ii) Unit option activity of the pre-expansion administrative/management employees allocable to us under the EPCO Agreement (based on each pre-expansion employee's percentage of time worked on our behalf).

	NUMBER OF UNITS	WEIGHTED-AVERAGE STRIKE PRICE
Outstanding at December 31, 1999	178,611	$ 1.95
Granted	664,000	$ 9.26
Exercised	(38,180)	$ 1.84
Forfeited	(20,000)	$ 9.00
Outstanding at December 31, 2000	784,431	$ 7.96
Granted	680,000	$ 16.67
Exercised	(150,585)	$ 6.01
Forfeited	(20,000)	$ 9.00
Outstanding at December 31, 2001	1,293,846	$ 12.74
Granted	249,000	$ 23.76
Exercised	(102,604)	$ 6.16
Outstanding at December 31, 2002	1,440,242	$ 15.12

Options exercisable at:	
December 31, 2000	140,431
December 31, 2001	155,846
December 31, 2002	383,742

RANGE OF STRIKE PRICES	OPTIONS OUTSTANDING AT DECEMBER 31, 2002	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE (IN YEARS)	WEIGHTED AVERAGE STRIKE PRICE	OPTIONS EXERCISABLE AT DECEMBER 31, 2002 NUMBER EXERCISABLE AT DECEMBER 31, 2002	WEIGHTED AVERAGE STRIKE PRICE
$.69 - $2.23	52,242	2.16	$ 1.58	52,242	$ 1.98
$7.75 -$9.00	331,500	6.75	$ 8.82	331,500	$ 8.82
$11.81	127,500	7.09	$ 11.81	-	-
$15.93 - $17.63	615,000	8.10	$ 16.30	-	-
$21.22 - $24.73	314,000	9.09	$ 23.61	-	-
	1,440,242			383,742	

The weighted average fair value of options granted was $3.17, $1.86, and $2.23 per option for the fiscal years ended December 31, 2002, 2001, and 2000, respectively.

We apply Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees", in accounting for employee Unit option awards whereby no compensation expense is recorded related to the options granted equal to the market value of the Unit on the date of grant. If compensation expense had been determined based on the Black-Scholes option pricing model value at the grant date for Unit option awards consistent with the provisions of SFAS No. 123, "Accounting for Stock-Based Compensation", our net income would have been as follows:

	2002	2001	2000
Net income:			
As reported....................	$96,952	$244,718	$223,068
Pro forma......................	95,858	243,888	222,406

The effects of applying SFAS No. 123 in the pro forma disclosure above may not be indicative of future amounts as additional awards in future years are anticipated.

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

	2002	2001	2000
Expected life of options............	7 years	7 years	7 years
Risk-free interest rate.............	3.10%	3.83%	6.44%
Expected dividend yield.............	5.65%	5.30%	10.00%
Expected Unit price volatility......	25%	20%	30%

14. 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, 2002, NGL and petrochemical volumes aggregating 4.2 million barrels were due to be redelivered to their owners along with 664 BBtus of natural gas.

Lease Commitments

We lease certain equipment and processing facilities under noncancelable and cancelable operating leases. Minimum future rental payments on such leases with terms in excess of one year at December 31, 2002 are as follows:

2003	$ 7,148
2004	5,081
2005	759
2006	676
2007	506
Thereafter	3,623
Total minimum obligations	$ 17,793

Third-party lease and rental expense included in operating income for the years ended December 31, 2002, 2001 and 2000 was approximately $16.4 million, $13.0 million and $10.6 million.

The operating lease commitments shown above 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 $12.6 million for 2003, $2.1 million for each of the years 2004 through 2009 and $0.7 million from 2010 through 2016. EPCO has assigned to us the purchase options associated with the retained leases. Should we decide to exercise our purchase options under the retained leases (which are at fair market value), up to $26.0 million is expected to be payable in 2004, $3.4 million in 2008 and $3.1 million in 2016.

Purchase Commitments

Product purchase commitments. We have long-term purchase commitments for NGLs, petrochemicals and natural gas with several 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 long-term volume commitments under these contracts.

	NGLS	PETROCHEMICALS	NATURAL GAS
	(MBbls)	(MBbls)	(BBtus)
2003	15,986	25,428	23,053
2004	13,172	22,857	20,439
2005	9,580	19,287	18,645
2006	5,910	13,399	18,645
2007	5,400	1,125	18,250
Thereafter	10,800		91,250
	60,848	82,096	190,282

Capital spending commitments. As of December 31, 2002, we had capital expenditure commitments totaling approximately $7.8 million, of which $6.3 million relates to our share of capital projects of unconsolidated affiliates.

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 12). This includes the costs associated with equity-based awards granted to these employees (see Note 13). At December 31, 2002, there were 1,194,242 options to purchase Common Units of our Limited Partner outstanding under the 1998 Plan that had been granted to operational and expansion-related administrative employees for which we were responsible for reimbursing EPCO for the costs of such awards. The weighted-average strike price of the Unit option awards granted to this group was $15.73 per Common Unit. At December 31, 2002, 275,242 of these Unit options were exercisable. An additional 100,000, 570,000 and 249,000 of these Unit options will be exercisable in 2003, 2004 and 2005, respectively.

When these operations and expansion-related administrative employees exercise a Unit option, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price paid for the Units awarded to the employee. We may reimburse EPCO for these costs in a number of ways including furnishing cash and transferring Common Units acquired by our 1999 Trust.

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.

15. SUPPLEMENTAL CASH FLOWS DISCLOSURE

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

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
(Increase) decrease in:			
Accounts and notes receivable	$ (130,476)	$ 229,525	$ (95,647)
Inventories	(84,254)	11,048	(13,044)
Prepaid and other current assets	15,419	(26,427)	2,351
Intangible assets			(5,228)
Other assets	(3,322)	163	(1,410)
Increase (decrease) in:			
Accounts payable	20,096	(78,270)	18,725
Accrued gas payable	262,527	(178,102)	135,048
Accrued expenses	8,111	(894)	4,430
Accrued interest	5,369	14,234	8,743
Other current liabilities	(6,921)	3,072	6,544
Other liabilities	(504)	(9,012)	8,123
Net effect of changes in operating accounts	$ 86,045	$ (34,663)	$ 68,635
Cash payments for interest, net of $1,083, $2,946 and $3,277 capitalized in 2002, 2001 and 2000, respectively	$ 82,535	$ 37,536	$ 17,774

During 2002 and 2001, we completed $1.8 billion in business acquisitions of which the purchase price allocation of each affected various balance sheet accounts. See Note 4 for information regarding the purchase price allocations of these transactions during 2002. During 2001, we acquired Acadian Gas from Shell. Its $225.7 million purchase price was allocated as follows: $83.1 million to current assets, $225.2 million to property, plant and equipment, $2.7 million to investments in unconsolidated affiliates, $83.9 million to current liabilities and $1.4 million to other long-term liabilities.

We record various financial instruments relating to commodity positions and interest rate hedging activities at their respective fair values using mark-to-market accounting. 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 2002, we made the first of two cash payments to acquire certain processing-related contract rights connected to Venice gas processing facility. Of the initial $4.6 million value of this intangible asset, $2.6 million was reclassified from construction-in-progress and $2.0 million represented the actual cash payment made to the third-party. 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. The remaining $2.0 million is scheduled to be paid during the third quarter of 2003.

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, 2002 and 2001 was $8.8 million and $5.8 million, respectively.

We did not have any cash payments for income taxes during 2002, 2001 or 2000. For additional information regarding our partnership and income taxes, see Note 1 and Note 11.

16. 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 Processing 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 Processing 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 our petrochemical marketing activities that are part of our Fractionation segment. In our Pipelines 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. 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 Other 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 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, 2002, we had open commodity financial instruments that settle at different dates through December 2003. 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 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 our 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, 2002. The fair value of these open positions was a liability of $26 thousand (based on market prices at that date).

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 will be 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.

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 are accounted for as cash flow hedges under 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 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 19). The settlement of these instruments resulted in our receipt of $5.4 million of cash. This amount will be 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 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 estimated amount to be reclassified from accumulated other comprehensive income to earnings during 2003 is $0.4 million. With the settlement of the treasury locks, the $3.6 million non-cash mark-to-market liability recorded at December 31, 2002 will be 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, the FASB is continuing to provide guidance about implementation issues. Since this guidance is still continuing, our initial conclusions regarding the application of SFAS No. 133 upon adoption may be altered. As a result, additional SFAS No. 133 transition 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, 2002 and 2001:

FINANCIAL INSTRUMENTS	AT DECEMBER 31, 2002 CARRYING VALUE	AT DECEMBER 31, 2002 FAIR VALUE	AT DECEMBER 31, 2001 CARRYING VALUE	AT DECEMBER 31, 2001 FAIR VALUE
Financial assets:				
Cash and cash equivalents	$ 20,795	$ 20,795	$ 137,823	$ 137,823
Accounts receivable	402,556	402,556	260,429	260,429
Commodity financial instruments (1)	513	513	9,992	9,992
Interest rate hedging financial instruments (2)	203	203	2,324	2,324
Financial liabilities:				
Accounts payable and accrued expenses	663,716	663,716	361,530	361,530
Fixed-rate debt (principal amount)	899,000	1,027,749	854,000	894,005
Variable-rate debt	1,346,000	1,346,000		
Commodity financial instruments (1)	539	539	3,206	3,206
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 have not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

17. SIGNIFICANT CONCENTRATIONS OF RISK

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 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. As a result, we established a $10.7 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.

Nature of Operations. 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.

18. 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 five reportable operating segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. The reportable segments are generally organized according to the type of services rendered (or process employed) and products produced and/or sold, as applicable. The segments are regularly evaluated by the Chief Executive Officer of the General Partner. Pipelines consists of NGL, petrochemical and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization, and polymer grade propylene fractionation services. Processing includes the natural gas processing business and its related NGL marketing activities. Octane Enhancement represents our equity interest in BEF, a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other operating segment consists of fee-based marketing services and various operational support activities.

We evaluate segment performance based on our measurement of segment gross operating margin. Gross operating margin reported for each segment represents operating income before depreciation and amortization, lease expense obligations retained by EPCO, gains and losses on the sale of assets and general and administrative expenses. In addition, segment gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges.

Gross operating margin by segment includes intersegment and intrasegment revenues (offset by corresponding intersegment and intrasegment expenses within the segments), which are generally based on transactions made at market-related rates. Our intersegment and intrasegment activities include, but are not limited to, the following types of transactions:

- NGL fractionation revenues from separating our NGL raw-make inventories into distinct NGL products using our fractionation plants for our NGL marketing activities (an intersegment revenue of Fractionation offset by an intersegment expense of Processing);
- liquids pipeline revenues from transporting our NGL volumes from gas processing plants on our pipelines to our NGL fractionation facilities (an intersegment revenue of Pipelines offset by an intersegment expense of Processing); and,
- the transfer sale of our NGL equity production extracted by our gas processing plants to our NGL marketing activities (an intrasegment revenue of Processing offset by an intrasegment expense of Processing).

For additional information regarding our revenue recognition policies, see Note 2.

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries, after elimination of all material intercompany (both intersegment and intrasegment) accounts and 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 and a means by which we conduct our operations to align our interests with a supplier of raw materials to a facility or a consumer of finished products from a facility. 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 our equity investees (see Note 7) perform supporting or complementary roles to our other business operations. For example, we use the Promix NGL fractionator to process NGLs extracted by our gas plants. The NGLs received from Promix then can be sold by our Processing segment's NGL marketing activities. Another example would be our relationship with the BEF MTBE facility. Our isomerization facilities process normal butane for this plant and our HSC pipeline transports MTBE for delivery to BEF's storage facility on the Houston Ship Channel. For additional information regarding our related party relationships with unconsolidated affiliates, see Note 12.

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 primarily along the western Gulf Coast in Texas, Louisiana and Mississippi. Our pipelines and related operations are in a number of regions of the United States including the Gulf of Mexico offshore Louisiana (certain natural gas pipelines); the south and southeastern United States (primarily in the Texas, Louisiana and Mississippi regions); and certain regions of the central and western United States. The Mid-America pipeline system extends from the Hobbs hub located on the Texas-New Mexico border to Wyoming along one route and to Minnesota, Wisconsin and Illinois along other routes. 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 property is construction-in-progress. Segment property represents those facilities and projects that contribute to gross operating margin and is net of accumulated depreciation on these assets. Since assets under construction do not generally contribute to segment gross operating margin, these assets are not included in the operating segment totals until they are deemed operational. Consolidated intangible assets and goodwill are allocated to the segments based on the classification of the assets to which they relate.

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

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Revenues (1)	$ 3,584,783	$ 3,154,369	$ 3,049,020
Operating costs and expenses (1)	(3,382,561)	(2,861,743)	(2,801,060)
Equity in income of unconsolidated affiliates (2)	35,253	25,358	24,119
Subtotal	237,475	317,984	272,079
Add: Depreciation and amortization in operating costs and expenses (3)	86,029	48,775	35,621
Retained lease expense, net in operating costs and expenses (4)	9,124	10,414	10,645
(Gain) loss on sale of assets in operating costs and expenses (3)	(1)	(390)	2,270
Total segment gross operating margin	$ 332,627	$ 376,783	$ 320,615

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(1) Amounts are comprised of both third party and related party totals from the Statements of Consolidated Operations and Comprehensive Income

(2) Amount taken from Statements of Consolidated Operations and Comprehensive Income

(3) Amount taken from Statements of Consolidated Cash Flows

(4) Amount represents leases paid by EPCO as reflected on the Statements of Consolidated Cash Flows

A reconciliation of our measurement of total segment gross operating margin to consolidated income before provision for income taxes and minority interest follows:

	FOR YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Total segment gross operating margin	$ 332,627	$ 376,783	$ 320,615
Depreciation and amortization	(86,029)	(48,775)	(35,621)
Retained lease expense, net	(9,124)	(10,414)	(10,645)
Gain (loss) on sale of assets	1	390	(2,270)
Selling, general and administrative	(42,664)	(30,812)	(28,345)
Consolidated operating income	194,811	287,172	243,734
Interest expense	(101,580)	(52,456)	(33,329)
Interest income from unconsolidated affiliates	139	15	1,662
Dividend income from unconsolidated affiliates	4,737	3,462	7,091
Interest income - other	2,846	7,773	4,295
Other, net	(230)	(1,104)	(272)
Consolidated income before provision for income taxes and minority interest	$ 100,723	$ 244,862	$ 223,181

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

	Operating Segments					Adjs. and Elims.	Consol. Totals
	Fractionation	Pipelines	Processing	Octane Enhancement	Other		
Revenues from third parties:							
2002	$ 592,681	$ 458,427	$2,049,202		$ 1,756		$ 3,102,066
2001	301,263	239,489	2,100,224		937		2,641,913
2000	361,919	15,648	2,310,706		1,268		2,689,541
Revenues from related parties:							
2002	19,121	161,727	301,747		122		482,717
2001	23,013	163,941	324,057		1,445		512,456
2000	35,076	12,524	310,269		1,610		359,479
Intersegment and intrasegment revenues:							
2002	203,750	102,330	604,981		401	$ (911,462)	-
2001	158,853	89,907	683,524		389	(932,673)	-
2000	177,963	55,690	630,155		375	(864,183)	-
Total revenues:							
2002	815,552	722,484	2,955,930		2,279	(911,462)	3,584,783
2001	483,129	493,337	3,107,805		2,771	(932,673)	3,154,369
2000	574,958	83,862	3,251,130		3,253	(864,183)	3,049,020
Equity income in unconsolidated affiliates:							
2002	7,179	19,505		$ 8,569			35,253
2001	6,945	12,742		5,671			25,358
2000	6,391	7,321		10,407			24,119
Total gross operating margin by segment:							
2002	129,000	214,932	(17,633)	8,569	(2,241)		332,627
2001	118,610	96,569	154,989	5,671	944		376,783
2000	129,376	56,099	122,240	10,407	2,493		320,615
Segment property (see Note 6):							
2002	444,016	2,166,524	133,888		16,825	49,586	2,810,839
2001	357,122	717,348	124,555		8,921	98,844	1,306,790
Investments in and advances to unconsolidated affiliates (see Note 7):							
2002	95,467	213,632	33,000	54,894			396,993
2001	93,329	216,029	33,000	55,843			398,201
Intangible Assets (see Note 8):							
2002	71,069	7,895	198,697				277,661
2001	7,857		194,369				202,226
Goodwill (see Note 8):							
2002	81,547						81,547

In general, our consolidated results of operations and financial position have been materially affected by acquisitions since late 1999. Our more significant acquisitions during this period were:

- William's Mid-America and Seminole pipelines in July 2002 for $1.2 billion;
- Diamond-Koch's propylene fractionation business in February 2002 for $239 million ;
- Diamond-Koch's NGL and petrochemical storage business in January 2002 for $129.6 million;
- Shell's Acadian Gas pipeline business in April 2001 for $243.7 million;
- El Paso's equity interests in four Gulf of Mexico natural gas pipelines in January 2001 for $113 million; and
- Shell's TNGL natural gas processing and related businesses in August 1999 for approximately $528.8 million.

See Note 4 for a description of acquisitions we completed during 2002.

19. SUBSEQUENT EVENTS

January 2003 contribution from Limited Partner. In January 2003, our Limited Partner completed a public offering of 14,662,500 Common Units from which we received a cash contribution of approximately $258.9 million, including our General Partner's $2.6 million capital contribution. We used $252.8 million of the proceeds to repay a portion of the indebtedness outstanding under the 364-Day Term Loan. The remaining balance was used for working capital purposes and other expenses.

January 2003 Senior Notes Offering. In January 2003, we issued $350 million in principal amount of 6.375% Senior Notes due 2013 ("Senior Notes C"), from which we received net proceeds before offering expenses of approximately $347.7 million. We used $347.0 million of the proceeds from this offering to repay a portion of the indebtedness outstanding under the 364-Day Term Loan. The remaining balance of proceeds was used for offering expenses.

February 2003 Senior Notes Offering. In February 2003, we issued $500 million in principal amount of 6.875% Senior Notes due 2033 ("Senior Notes D"), from which we received net proceeds before offering expenses of approximately $489.8 million. We used $421.4 million of the proceeds from this offering to repay the remaining principal balance outstanding under the 364-Day Term Loan. An additional $60.0 million in proceeds was used to reduce the amount outstanding under the 364-Day Revolving Credit facility. The remaining balance of proceeds was used for working capital purposes and offering expenses.

Purchase of remaining 50% interest in EPIK. In March 2003, we purchased the remaining ownership interests in EPIK from Idemitsu LPG USA Corporation for $19.0 million. The purchase price is subject to certain post-closing adjustments that we expect to finalize during the second quarter of 2003.

20. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table contains selected quarterly financial data for 2002 and 2001.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
FOR THE YEAR ENDED DECEMBER 31, 2001:				
Revenues	$ 836,315	$ 959,397	$ 723,329	$ 635,328
Operating income	54,417	108,390	87,478	36,887
Income before minority interest	52,939	93,437	76,003	22,483
Minority interest	(23)	(44)	(46)	(31)
Net income	52,916	93,393	75,957	22,452
FOR THE YEAR ENDED DECEMBER 31, 2002:				
Revenues	$ 662,054	$ 786,257	$ 943,313	$1,193,159
Operating income	(928)	39,889	68,374	87,476
Income before minority interest	(17,098)	22,480	36,307	57,400
Minority interest	(53)	(33)	(988)	(1,063)
Net income (loss)	(17,151)	22,447	35,319	56,337

We recorded a net loss during the first quarter of 2002 due to commodity hedging losses resulting from an unexpected increase in natural gas prices. Overall, we recorded $51.3 million of commodity hedging losses during 2002 compared to $101.3 million of income from such activities during 2001 (see Note 16). Net income for the second half of 2002 improved relative to the first half of 2002 primarily due to the acquisition of Mid-America and Seminole in July 2002 (see Note 4).

ENTERPRISE PRODUCTS OPERATING 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					
2002	$ 20,642		$ 5,367 (b)	$ (4,813) (d)	$ 21,196
2001	10,916	$ 6,200 (a)	6,522 (c)	(2,996) (d)	20,642
2000	15,871			(4,955) (d)	10,916
OTHER CURRENT ASSETS:					
Additional credit reserve for Enron					
2002	$ 4,305			$ (4,305) (b)	
2001			4,305 (a)		4,305
OTHER CURRENT LIABILITIES:					
Reserve for environmental liabilities					
2002			102 (e)	(93) (e)	9
Reserve for inventory gains and losses (f)					
2002	2,029	500 (g)		(1,258) (h)	1,271
2001	5,690	500 (g)		(4,161) (h)	2,029
2000	2,894	500 (g)	2,296 (h)		5,690
OTHER LONG-TERM LIABILITIES:					
Reserve for environmental liabilities					
2002		45 (e)	90 (e)		135

The following explanations describe significant transactions affecting the amounts shown in the table above:

(a) In December 2001, Enron North America filed for protection under Chapter 11 of the U.S. Bankruptcy Code. As a result, we established a $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, $6.3 million offsets billed amounts due from Enron recorded in Accounts Receivable-Trade. The remaining $4.3 million in reserve offsets various unbilled commodity financial instrument positions, which were reclassified to "Additional credit reserve from Enron".

(b) The $4.3 million in unbilled positions was invoiced in early 2002 as the financial instruments settled (see Note 17). These amounts were reclassified from the "Additional credit reserve for Enron" account to "Allowance for doubtful accounts" accordingly.

(c) The allowance account was increased in April 2001 as a result of accounts acquired from Acadian Gas.

(d) In the normal course of business, we charged the allowance account for customer amounts that have been deemed uncollectible.

(e) In July 2002, we acquired the Mid-America pipeline from Williams. This operation had existing minor environmental liabilities that were of a current and long-term nature that we recorded using purchase accounting. Since the acquisition, various vendor invoices have been charged against the current portion of the reserve. In addition, the long-term portion of the reserve has been increased due to revisions in management estimates of the future liability to remediate the sites involved.

(f) 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.

(g) The reserve is increased based on management's estimate of annual net product storage losses.

(h) Product losses are charged against and reduce the reserve balance. 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 adjusted by $2.4 million.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized, in the City of Houston, State of Texas on April 17, 2003.

ENTERPRISE PRODUCTS PARTNERS L.P. (A Delaware Limited Partnership)
ENTERPRISE PRODUCTS OPERATING L.P. (A Delaware Limited Partnership)
By: ENTERPRISE PRODUCTS GP, LLC, as General Partner for both registrants

By: /s/ Michael J. Knesek
Name: Michael J. Knesek
Title: Vice President, Controller and Principal Accounting Officer of the General Partner

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities indicated below on April 17, 2003.

SIGNATURE	TITLE (OF ENTERPRISE PRODUCTS GP, LLC)
/s/ Dan L. Duncan Dan L. Duncan	Chairman of the Board and Director
/s/ O.S. Andras O. S. Andras	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ Richard H. Bachmann Richard H. Bachmann	Executive Vice President, Chief Legal Officer, Secretary and Director
/s/ Michael A. Creel Michael A. Creel	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Michael J. Knesek Michael J. Knesek	Vice President, Controller and Principal Accounting Officer
/s/ Randa D. Williams Randa D. Williams	Director
J. A. Berget	Director
/s/ Dr. Ralph S. Cunningham Dr. Ralph S. Cunningham	Director
J. R. Eagan	Director
A. Y. Noojin, III	Director
/s/ Richard S. Snell Richard S. Snell	Director
/s/ Lee W. Marshall, Sr. Lee W. Marshall, Sr.	Director

SARBANES-OXLEY SECTION 302 CERTIFICATIONS

CERTIFICATION OF O.S. ANDRAS, PRINCIPAL EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

I, O.S. Andras, the Principal Executive Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P., certify that:

1. I have reviewed this annual report on Form 10-K/A of Enterprise Products Partners L.P.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

    a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
    b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
    c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent function):

    a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: April 17, 2003

/s/ O.S. Andras
\---
Name: O.S. Andras
Title: Principal Executive Officer of our General Partner, Enterprise Products GP, LLC

CERTIFICATION OF MICHAEL A. CREEL, PRINCIPAL FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

I, Michael A. Creel, the Principal Financial Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P., certify that:

1. I have reviewed this annual report on Form 10-K/A of Enterprise Products Partners L.P.;

2 Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

    a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
    b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
    c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent function):

    a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: April 17, 2003

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Principal Financial Officer of our General Partner, Enterprise Products GP, LLC

CERTIFICATION OF O.S. ANDRAS, PRINCIPAL EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS OPERATING L.P.

I, O.S. Andras, the Principal Executive Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Operating L.P., certify that:

1. I have reviewed this annual report on Form 10-K/A of Enterprise Products Operating L.P.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: April 17, 2003

/s/ O.S. Andras

Name: O.S. Andras
Title: Principal Executive Officer of our General Partner, Enterprise Products GP, LLC

CERTIFICATION OF MICHAEL A. CREEL, PRINCIPAL FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS OPERATING L.P.

I, Michael A. Creel, the Principal Financial Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Operating L.P., certify that:

1. I have reviewed this annual report on Form 10-K/A of Enterprise Products Operating L.P.;

2 Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: April 17, 2003

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Principal Financial Officer of our General Partner, Enterprise Products GP, LLC

INDEX TO EXHIBIT

EXHIBIT NO.		EXHIBIT*
2.1	--	Purchase and Sale Agreement between Coral Energy, LLC and Enterprise Products Operating L.P. dated September 22, 2000 (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 26, 2000).
2.2	--	Purchase and Sale Agreement dated January 16, 2002 by and between Diamond-Koch, L.P. and Diamond-Koch III, L.P. and Enterprise Products Texas Operating L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 8, 2002.)
2.3	--	Purchase and Sale Agreement dated January 31, 2002 by and between D-K Diamond-Koch, L.L.C., Diamond-Koch, L.P. and Diamond-Koch III, L.P. as Sellers and Enterprise Products Operating L.P. as Buyer (incorporated by reference to Exhibit 10.2 to Form 8-K filed February 8, 2002).
2.4	--	Purchase Agreement by and between E-Birchtree, LLC and Enterprise Products Operating L.P. dated July 31, 2002 (incorporated by reference to Exhibit 2.2 to Form 8-K filed August 12, 2002).
2.5	--	Purchase Agreement by and between E-Birchtree, LLC and E-Cypress, LLC dated July 31, 2002 (incorporated by reference to Exhibit 2.1 to Form 8-K filed August 12, 2002).
3.1	--	First Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC dated as of September 17, 1999 (incorporated by reference to Exhibit 99.8 to the Form 8-K/A-l filed October 27, 1999).
3.2**	--	Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of the General Partner dated as of September 19, 2002.
3.3	--	Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated May 15, 2002 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 13, 2002).
3.4	--	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated August 7, 2002 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 13, 2002).
3.5	--	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated December 17, 2002 (incorporated by reference to Exhibit 3.5 to Form 8-K filed December 17, 2002).
3.6	--	Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. dated as of July 31, 1998 (incorporated by reference to Exhibit 3.2 to Registration Statement on Form S-1/A filed July 21, 1998).
4.1	--	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.2	--	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4 filed January 28, 2003).
4.3**	--	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee.
4.4	--	Global Note representing $350 million principal amount of 6.375% Series A Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4 filed January 28, 2003).
4.5**	--	Rule 144 A Global Note representing $499.2 million principal amount of 6.875% Series A Senior Notes due 2033 with attached Guarantee.

4.6**	--	Regulation S Global Note representing $800,000 principal amount of 6.875% Series A Senior Notes due 2033 with attached Guarantee.
4.7	--	Form of Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (included in Exhibit 4.2).
4.8**	--	Form of Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (included in Exhibit 4.3).
4.9	--	Registration Rights Agreement dated as of January 22, 2003, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.5 to Registration Statement on Form S-4 filed January 28, 2003).
4.10**	--	Registration Rights Agreement dated as of February 14, 2003, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein.
4.11	--	Global Note representing $350 million principal amount of 8.25% Senior Notes due 2005 (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 10, 2000).
4.12	--	Global Note representing $450 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.13	--	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.14	--	$250 Million Multi-Year Revolving Credit Facility dated as of November 17, 2000, among Enterprise Products Operating L.P., First Union National Bank, as Administrative Agent, Bank One, NA, as Documentation Agent, the Chase Manhattan Bank, as Syndication Agent, and the several banks from time to time parties thereto, with First Union Securities, Inc. and Chase Securities Inc. as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 4.2 to Form 8-K filed January 24, 2001).
4.15	--	$150 Million 364-Day Revolving Credit Facility November 17, 2000, among Enterprise Products Operating L.P., First Union National Bank, as Administrative Agent, Bank One, NA, as Documentation Agent, the Chase Manhattan Bank, as Syndication Agent, and the several banks from time to time parties thereto, with First Union Securities, Inc. and Chase Securities Inc. as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 24, 2001).
4.16	--	Guaranty Agreement dated as of November 17, 2000, by Enterprise Products Partners L.P. in favor of First Union National Bank, as Administrative Agent, with respect to the $250 Million Multi-Year Revolving Credit Facility included as Exhibit 4.4 above (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 24, 2001).
4.17	--	Guaranty Agreement dated as of November 17, 2000, by Enterprise Products Partners L.P. in favor of First Union National Bank, as Administrative Agent, with respect to the $150 Million 364-Day Revolving Credit Facility (incorporated by reference to Exhibit 4.5 to Form 8-K filed January 24, 2001).
4.18	--	First Amendment to Multi-Year Credit Facility dated April 19, 2001 (incorporated by reference to Exhibit 4.12 to Form 10-Q filed May 14, 2001).
4.19	--	Second Amendment to Multi-Year Revolving Credit Facility dated April 14, 2002 (incorporated by reference to Exhibit 4.14 to Form 10-Q filed May 14, 2002).
4.20	--	Third Amendment to Multi-Year Revolving Credit Facility dated July 31, 2002 (incorporated by reference to Exhibit 4.1 to Form 10-Q filed August 12, 2002).
4.21	--	Fourth Amendment to Multi-Year Revolving Credit Facility dated effective as of November 15, 2002 (incorporated by reference to Exhibit 4.21 to Form 10-Q filed November 13, 2002).
4.22	--	First Amendment to 364-Day Credit Facility dated November 6, 2001, effective as of November 16, 2001 (incorporated by reference to Exhibit 4.13 to Form 10-Q filed August 13, 2002).
4.23	--	Second Amendment to 364-Day Revolving Credit Facility dated April 24, 2002 (incorporated by reference to Exhibit 4.15 to Form 10-Q filed May 14, 2002).
4.24	--	Third Amendment to 364-Day Revolving Credit Facility dated July 31, 2002 (incorporated by reference to Exhibit 4.2 to Form 8-K filed August 12, 2002).
4.25	--	Contribution Agreement dated September 17, 1999 (incorporated by reference to Exhibit "B" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.26	--	Registration Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "E" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.27	--	Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "C" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).

10.1	--	$1.2 Billion 364-Day Term Credit Facility dated as of July 31, 2002, among Enterprise Products Operating Partnership L.P., Wachovia Bank, National Association, as Administrative Agent, Lehman Commercial Paper Inc., as Co-Syndication Agent, Royal Bank of Canada, as Co- Syndication Agent and Arranger, with Wachovia Securities, Inc. and Lehman Brothers Inc., as Lead Arrangers and Joint Bookrunners and RBC Capital Markets, as Arranger (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 12, 2002).
10.2	--	Guaranty Agreement dated as of July 31, 2002 by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent, with respect to the $1.2 Billion 364-Day Term Credit Facility (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 12, 2002).
10.3	--	EPCO Agreement among Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products Company dated July 31, 1998 (incorporated by reference to Exhibit 10.3 to Registration Statement on Form S-4 filed January 28, 2003).
10.4	--	Transportation Contract between Enterprise Products Operating L.P. and Enterprise Transportation Company dated June 1, 1998 (incorporated by reference to Exhibit 10.3 to Registration Statement Form S-1/A filed July 8,1998).
10.5	--	Partnership Agreement among Sun BEF, Inc., Liquid Energy Fuels Corporation and Enterprise Products Company dated May 1, 1992 (incorporated by reference to Exhibit 10.5 to Registration Statement on Form S-1 filed May 13, 1998).
10.6	--	Propylene Facility and Pipeline Agreement between Enterprise Petrochemical Company and Hercules Incorporated dated December 13, 1978 (incorporated by reference to Exhibit 10.9 to Registration Statement on Form S-l filed May 13, 1998).
10.7	--	Restated Operating Agreement for the Mont Belvieu Fractionation Facilities Chambers County, Texas among Enterprise Products Company, Texaco Producing Inc., El Paso Hydrocarbons Company and Champlin Petroleum Company dated July 17, 1985 (incorporated by reference to Exhibit 10.10 to Registration Statement on Form S-l/A filed July 8,1998).
10.8	--	Amendment to Propylene Facility and Pipeline Agreement and Propylene Sales Agreement between HIMONT U.S.A., Inc. and Enterprise Products Company dated January 1, 1993 (incorporated by reference to Exhibit 10.12 to Registration Statement on Form S-l/A filed July 8, 1998).
10.9	--	Amendment to Propylene Facility and Pipeline Agreement and Propylene Sales Agreement between HIMONT U.S.A., Inc. and Enterprise Products Company dated January 1, 1995 (incorporated by reference to Exhibit 10.13 to Registration Statement on Form S-l/A filed July 8, 1998).
10.10	--	Fourth Amendment to Conveyance of Gas Processing Rights among Tejas Natural Gas Liquids, LLC and Shell Oil Company, Shell Exploration & Production Company, Shell Offshore Inc., Shell Deepwater Development Inc., Shell Land & Energy Company and Shell Frontier Oil & Gas Inc. dated August 1, 1999 (incorporated by reference to Exhibit 10.14 to Form 10-Q filed November 15, 1999).
10.11	--	Fifth Amendment to Conveyance of Gas Processing Rights dated as of April 1, 2001 among Enterprise Gas Processing, LLC, Shell Oil Company, Shell Exploration & Production Company, Shell Offshore Inc., Shell Consolidated Energy Resources, Inc., Shell Land & Energy Company and Shell Frontier Oil & Gas, Inc. (incorporated by reference to Exhibit 10.13 to Form 10-Q filed August 13, 2001).
10.12***	--	Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.1 to Post-Effective Amendment No. 1 to Registration Statement on Form S-8 filed March 13, 2003).
10.13***	--	Form of Option Grant Award under the 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.2 to Post-Effective Amendment No. 1 to Registration Statement on Form S-8 filed March 13, 2003).
12.1**	--	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2002, 2001, 2000, 1999 and 1998 for Enterprise Products Partners L.P.
12.2**	--	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2002, 2001, 2000, 1999 and 1998 for Enterprise Products Operating L.P.
21.1**	--	List of Subsidiaries of the Registrants.
23.1#	--	Consent of Deloitte & Touche LLP.

99.1**	--	Audited Balance Sheet of Enterprise Products GP, LLC, as of December 31, 2002.
99.2#	--	Section 1350 Certifications

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P. is 1-14323 and the Commission file number for Enterprise Products Operating L.P. is 333-93239-01.

** Previously filed with our original Form 10-K on March 31, 2003.

*** Identifies management contract and compensatory plan arrangements

\# Filed with this report.

EXHIBIT 23.1

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Enterprise Products Partners L.P. and Enterprise Products Operating L.P.'s (i) Registration Statement No. 333-36856 of Enterprise Products Partners L.P. on Form S-8; (ii) Registration Statement No. 333-102778 of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. on Form S-3; (iii) Registration Statement No. 333-102776 of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. on Form S-4; and (iv) Registration Statement No. 333-82486 of Enterprise Products Partners L.P. on Form S-8 of our reports dated March 7, 2003 (such reports express an unqualified opinion and include explanatory paragraphs referring to the change in accounting for goodwill in 2002 and derivative instruments in 2001), appearing in the respective Annual Reports on Form 10-K/A of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. for the year ended December 31, 2002.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
April 17, 2003

EXHIBIT 99.2

CERTIFICATION OF O.S.ANDRAS, CHIEF EXECUTIVE OFFICER
OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF
ENTERPRISE PRODUCTS OPERATING L.P. AND ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this combined annual report of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. (collectively, the "Registrants") on Form 10-K/A for the year ending December 31, 2002 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, O.S. Andras, Chief Executive Officer of Enterprise Products GP, LLC, the General Partner of the Registrants, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrants.

/s/ O.S. Andras

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Name: O.S. Andras
Title: Chief Executive Officer of Enterprise Products GP, LLC
on behalf of Enterprise Products Operating L.P. and
Enterprise Products Partners L.P.

Date: April 17, 2003

A signed original of this written statement required by Section 906 has been provided to the Registrants and will be retained by the Registrants and furnished to Securities and Exchange Commission or its staff upon request.

CERTIFICATION OF MICHAEL A. CREEL, CHIEF FINANCIAL OFFICER
OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF
ENTERPRISE PRODUCTS OPERATING L.P. AND ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with the combined annual report of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. (collectively, the "Registrants") on Form 10-K/A for the year ending December 31, 2002 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Financial Officer of Enterprise Products GP, LLC, the General Partner of the Registrants, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrants.

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Chief Financial Officer of Enterprise Products GP, LLC
on behalf of Enterprise Products Operating L.P. and
Enterprise Products Partners L.P.

Date: April 17, 2003

A signed original of this written statement required by Section 906 has been provided to the Registrants and will be retained by the Registrants and furnished to Securities and Exchange Commission or its staff upon request.