FILED PURSUANT TO RULE 424B3
REGISTRATION NO. 333-56082
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THE INFORMATION IN THIS PRELIMINARY PROSPECTUS SUPPLEMENT IS NOT COMPLETE AND MAY BE CHANGED. THIS PROSPECTUS SUPPLEMENT AND THE ATTACHED PROSPECTUS ARE NOT AN OFFER TO SELL THESE SECURITIES AND ARE NOT SOLICITING AN OFFER TO BUY THESE SECURITIES IN ANY STATE WHERE THE OFFER OR SALE IS NOT PERMITTED.

SUBJECT TO COMPLETION, DATED SEPTEMBER 27, 2002

PROSPECTUS SUPPLEMENT
(TO PROSPECTUS DATED MARCH 27, 2001)

[ENTERPRISE PRODUCTS PARTNERS L.P. LOGO]

ENTERPRISE PRODUCTS PARTNERS L.P.

9,300,000 COMMON UNITS

REPRESENTING LIMITED PARTNER INTERESTS

We are offering to sell 9,300,000 common units, including 1,800,000 common units to be offered to entities controlled by Dan L. Duncan, the Chairman of our general partner, and to O.S. Andras, the President and Chief Executive Officer of our general partner. Our common units trade on the New York Stock Exchange under the symbol "EPD." The last reported sales price of our common units on the NYSE on September 26, 2002 was $20.92 per common unit.

INVESTING IN THE COMMON UNITS INVOLVES RISK. "RISK FACTORS" BEGIN ON PAGE S-9 OF THIS PROSPECTUS SUPPLEMENT AND ON PAGE 3 OF THE ACCOMPANYING PROSPECTUS.

	PER COMMON UNIT	TOTAL
Public offering price....................................	$	$
Underwriting discount (1)................................	$	$
Proceeds to Enterprise Products Partners (before expenses)..	$	$

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(1) The underwriters will receive no underwriting discount or commission on the sale of the 1,800,000 common units described above or on the sale of up to 10,000 common units to other members of our senior management.

We have granted the underwriters a 30-day option to purchase up to 1,125,000 common units on the same terms and conditions as set forth above to cover over-allotments of common units, if any.

NEITHER THE SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THESE SECURITIES OR DETERMINED IF THIS PROSPECTUS SUPPLEMENT OR THE ACCOMPANYING PROSPECTUS IS TRUTHFUL OR COMPLETE. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

Lehman Brothers, on behalf of the underwriters, expects to deliver the common units on or about , 2002.

LEHMAN BROTHERS
GOLDMAN, SACHS & CO.
UBS WARBURG
RBC CAPITAL MARKETS
WACHOVIA SECURITIES
MCDONALD INVESTMENTS
RAYMOND JAMES
SANDERS MORRIS HARRIS

, 2002

[INSIDE COVER ART]

This document is in two parts. The first part is this prospectus supplement, which describes the terms of this offering of common units. The second part is the accompanying prospectus, which gives more general information, some of which may not apply to the common units.

You should rely only on the information contained or incorporated by reference in this prospectus supplement or the accompanying prospectus. We have not authorized anyone to provide you with different information. We are not making an offer of these securities in any state where the offer is not permitted. You should not assume that the information contained in this prospectus supplement or the accompanying prospectus is accurate as of any date other than the date on the front of these documents or that any information we have incorporated by reference is accurate as of any date other than the date of the document incorporated by reference.

TABLE OF CONTENTS

SUMMARY

This summary highlights information contained elsewhere in this prospectus supplement. You should read carefully the entire prospectus supplement, the accompanying prospectus, the documents incorporated by reference and the other documents to which we refer for a more complete understanding of this offering. You should read "Risk Factors" beginning on page S-9 of this prospectus supplement and on page 3 of the accompanying prospectus for more information about important risks that you should consider before buying common units in this offering. We have provided definitions for some of the industry terms, names of companies and other abbreviations used in this prospectus supplement in the "Glossary" beginning on page S-69 of this prospectus supplement. The information presented in this prospectus supplement assumes that the underwriters do not exercise their over-allotment option. All references in this prospectus supplement to numbers of units, earnings per unit or unit price give effect to our two-for-one unit split on May 15, 2002. All references in the accompanying prospectus to numbers of units, earnings per unit or unit price do not give effect to the two-for-one unit split. Pro forma financial results presented in this prospectus supplement give effect to material acquisitions we completed in 2002. For a more complete explanation of our pro forma financial results, please read "Enterprise Products Partners L.P. Unaudited Pro Forma Consolidated Financial Statements" beginning on page F-2.

ENTERPRISE PRODUCTS PARTNERS L.P.

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, agricultural and industrial fuels. Our asset platform in the Gulf Coast region, combined with our recently acquired Mid-America and Seminole pipeline systems, creates 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."

For the year ended December 31, 2001, we had revenues of $3.2 billion, operating margin of $376.8 million and net income of $242.2 million. On a pro forma basis for the year ended December 31, 2001, we had revenues of $4.0 billion, operating margin of $556.2 million and net income of $257.7 million. Our business has five reportable segments:

Pipelines. Our Pipelines segment includes approximately 14,000 miles of NGL, petrochemical and natural gas pipelines located primarily in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. This segment also includes our storage and import/export terminalling businesses.

Fractionation. Our Fractionation segment includes eight NGL fractionators, the largest commercial isomerization complex in the United States and four propylene fractionation facilities. NGL fractionators separate mixed NGL streams produced as by-products of natural gas production and crude oil refining into discrete NGL products: ethane, propane, isobutane, normal butane and natural gasoline. Our isomerization complex converts normal butane into mixed butane, which is subsequently fractionated into normal butane, isobutane and high purity isobutane. Our propylene fractionators separate refinery-sourced propane/propylene mix into propane, propylene and mixed butane.

Processing. Our Processing segment is comprised of our natural gas processing business and related merchant activities. At the core of our natural gas processing business are 13 gas plants, located primarily in south Louisiana, that process raw natural gas into a product that meets pipeline and industry specifications by removing NGLs and impurities. In connection with our processing businesses, we receive a portion of the NGL production from these gas plants. This equity NGL production, together with the NGLs we purchase, supports the merchant activities included in this operating segment.

Octane Enhancement and Other. Our Octane Enhancement segment consists of a 33.3% equity investment in BEF, which owns a facility that produces motor gasoline additives used to enhance octane. Our Other segment consists primarily of fee-based marketing services.

We completed the initial public offering of our common units in July 1998 at a unit price of $11.00 per unit. On September 12, 2002, we announced that the board of directors of our general partner approved an increase in our quarterly distribution rate to $0.345 per unit, or $1.38 on an annualized basis, which represents an approximate 53% increase in our quarterly distribution rate since our initial public offering. Since our initial public offering, we have completed investments with a combined value of over $3.1 billion. As demonstrated by our July 2002 acquisitions of the Mid-America and Seminole pipeline systems, we are committed to growing our fee-based businesses. We believe that these acquisitions will increase our gross margins derived from fee-based businesses to between 85% and 90% of total gross margin, based on average natural gas and NGL product prices for the last ten years.

RECENT SIGNIFICANT ACQUISITIONS

Acquisition of Mid-America and Seminole Pipeline Systems. On July 31, 2002, we completed the acquisition of a 98% interest in the Mid-America pipeline system and a 78% interest in the Seminole pipeline system from The Williams Companies, Inc. for approximately $1.2 billion in cash. Mid-America is a 7,226-mile NGL pipeline system connecting the Hobbs hub located on the Texas-New Mexico border with supply regions in the Rocky Mountains and with supply regions and markets in the Midwest. The Mid-America pipeline system is comprised of three major segments: the Conway North pipeline, the Conway South pipeline and the Rocky Mountain pipeline. In 2001, average transportation volumes on the Mid-America pipeline system were approximately 641 MBPD. Seminole 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 the Permian basin to Mont Belvieu, Texas. In 2001, average transportation volumes on the Seminole pipeline system were approximately 241 MBPD, of which approximately 32% were transported to our Mont Belvieu facilities for fractionation, storage and distribution. Major customers utilizing the Mid-America and Seminole pipeline systems include BP, Burlington, ConocoPhillips, Duke, Equistar and Williams.

The acquisition of the Mid-America and Seminole pipeline systems 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, and provides additional access to new end markets for NGL products. The Conway South segment of the Mid-America pipeline system connects Conway to the Hobbs hub, which is, in turn, connected to Mont Belvieu via the Seminole pipeline system. The 2,740-mile Conway North pipeline links the market hub in Conway with petrochemical and refining customers and propane markets in the upper Midwest.

Acquisition of Propylene Fractionation Business. 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 acquisition includes a 66.7% interest in a polymer grade propylene fractionation facility located in Mont Belvieu, Texas, a 50% interest in a polymer grade propylene export terminal located on the Houston Ship Channel and varying interests in several supporting distribution pipelines and related equipment. This Mont Belvieu facility has the capacity to produce approximately 41 MBPD of polymer grade propylene.

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 30 salt dome storage caverns located in Mont Belvieu, Texas with a useable capacity of 68 million barrels, local distribution pipelines and related equipment. The facilities provide storage services for mixed NGL products and olefins, such as ethylene and propylene. The facilities, together with our existing storage facilities, serve the largest concentration of petrochemical and refinery facilities in the United States and represent the largest NGL and petrochemical underground storage operation in the world.

OUR 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.

COMPETITIVE STRENGTHS

We believe that our integrated network of midstream energy assets is well-positioned to benefit from demand for our services from producers and consumers of natural gas, NGLs and petrochemicals. Our most significant competitive strengths are:

Strategic locations. Our operations are strategically located to serve the major supply basins of NGL-rich natural gas, the major NGL markets and storage hubs in North America and international markets. Our location in these markets ensures continued access to natural gas, NGL and petrochemical supply volumes, anticipated demand growth and business expansion opportunities.

Integrated platform of assets. Our assets are physically linked to form the only integrated system connecting the largest supply basins to the largest consuming markets, both domestic and international.

Relationships with major oil, natural gas and petrochemical companies. We have long-term relationships with many of our suppliers and customers, including BP, ChevronTexaco, Dow Chemical, Exxon Mobil, Lyondell and Shell. We jointly own facilities with many of these customers, which either provide raw materials to or consume the end products produced from our facilities.

Large-scale, low-cost integrated operations. We believe the operating costs of our large-scale facilities are either competitive with or significantly lower than those of our competitors.

Experienced operator. We have historically operated our largest natural gas processing and fractionation facilities and most of our pipelines.

Experienced management team. Our senior management team averages more than 27 years of industry experience. Through our acquisition of Shell's midstream energy business and the Diamond-Koch propylene fractionation business, we have broadened and deepened our senior management team.

OUR RELATIONSHIP WITH SHELL

One of our significant strengths is our extensive relationship with Shell. Over the last three years, we have made several acquisitions from Shell, including our $529 million acquisition of TNGL, our $100 million acquisition of the Lou-Tex propylene pipeline system and our $244 million acquisition of Acadian Gas. Following this offering, Shell will own an approximate 21.9% limited partner interest in us and 30% of our general partner. Shell currently owns a 45.4% equity interest in one of our propylene fractionators at our Mont Belvieu complex, a 66% interest in our Nemo natural gas pipeline system and a 50% interest in each of our Nautilus, Manta Ray, Stingray and Triton natural gas pipeline systems. During 2001, Shell generated $333.3 million, or 10.5%, of our revenues.

PARTNERSHIP STRUCTURE AND MANAGEMENT

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. The chart on the following page depicts our organizational and ownership structure after giving effect to this offering. Upon consummation of the offering of our common units:

- there will be 28,585,964 publicly held common units outstanding, representing a 15.3% limited partner interest in us;

- EPCO and its affiliates will own 81,608,802 common units and 32,114,804 subordinated units representing an aggregate 60.8% limited partner interest in us;

- Shell will own 31,000,000 common units and 10,000,000 special units representing a 21.9% limited partner interest in us; and

- Our general partner will continue to own a combined 2.0% general partner interest in us and all of our incentive distribution rights.

Our principal executive offices are located at 2727 North Loop West, Houston, Texas 77008, and our phone number is (713) 880-6500.

OWNERSHIP OF ENTERPRISE PRODUCTS PARTNERS L.P. AND THE OPERATING PARTNERSHIP

	UNITS	PERCENTAGE INTEREST (on a combined basis)
Public common units..................................	28,585,964	15.3%
EPCO common units....................................	81,608,802	43.6%
EPCO subordinated units.............................	32,114,804	17.2%
Shell common units...................................	31,000,000	16.6%
Shell special units..................................	10,000,000	5.3%
General partner interest (70% EPCO; 30% Shell)(1)....		2.0%
Total..		100.0%

[CHART]

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(1) 2.0% general partner interest on a combined basis, including a 1.0% general partner interest in Enterprise Products Partners L.P. and a 1.0101% general partner interest in the operating partnership.

THE OFFERING

Common units offered	9,300,000 common units, including 1,800,000 common units to be offered to members of our senior management or their affiliates; and 10,425,000 common units if the underwriters exercise their over-allotment option in full.
Units outstanding after this offering	141,194,766 common units or 142,319,766 common units if the underwriters exercise their over-allotment option in full; 32,114,804 subordinated units; and 10,000,000 special units.
Use of proceeds	We will use the net proceeds from this offering to retire a portion of the indebtedness outstanding under our $1.2 billion senior unsecured 364-day term loan incurred to finance the Mid-America and Seminole acquisitions. For a description of our term loan, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Our Liquidity and Capital Resources -- Our Debt Obligations."
Cash distributions	Under our partnership agreement, we must distribute all of our cash on hand as of the end of each quarter, less reserves established by our general partner. We refer to this cash as "available cash," and we define its meaning in our partnership agreement. On August 12, 2002, we paid a quarterly cash distribution for the second quarter of 2002 of $0.335 per common unit, or $1.34 per common unit on an annualized basis. On September 12, 2002, we announced that the board of directors of our general partner approved an increase in our quarterly distribution to $0.345 per common unit, or $1.38 per common unit on an annualized basis, commencing with the distribution payable in the fourth quarter of this year. When quarterly cash distributions exceed $0.253 per unit in any quarter, our general partner receives a higher percentage of the cash distributed in excess of that amount, in increasing percentages up to 50% if the quarterly cash distributions exceed $0.392. Our special units do not accrue distributions and are not entitled to cash distributions until their conversion into an equal number of common units on August 1, 2003. For a description of our cash distribution policy, please read "Description of Common Units -- Cash Distribution Policy" in the accompanying prospectus.
Estimated ratio of taxable income to distributions	We estimate that if you own the common units you purchase in this offering through December 31, 2005, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be less than 10% of the cash distributed with respect to that period. Please read "Tax Considerations" in this prospectus supplement for the basis of this estimate.
New York Stock Exchange symbol	EPD

SUMMARY HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following table sets forth for the periods and at the dates indicated selected historical and pro forma financial and operating data for us. The selected historical income statement data for each of the three years in the period ended December 31, 2001 and the selected balance sheet data for each of the two years in the period ended December 31, 2001 are derived from and should be read in conjunction with our audited financial statements for these periods included elsewhere in this prospectus supplement. The selected historical data for the six month periods ending June 30, 2001 and 2002 are derived from and should be read in conjunction with our unaudited financial statements included elsewhere in this prospectus supplement. The table should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations."

The summary pro forma financial statements of Enterprise Products Partners show the pro forma effect of:

- the Mid-America and Seminole acquisitions including the $1.2 billion senior unsecured 364-day term loan;

- the propylene fractionation and storage business acquired from Diamond-Koch in 2002 and the acquisition of Acadian Gas in 2001;

- the completion of this offering;

- the general partner's proportionate capital contribution; and

- the application of the net proceeds from this offering to repay a portion of indebtedness outstanding under the term loan.

The summary pro forma financial and operating data for the year ended December 31, 2001 and six months ended June 30, 2002 are derived from the unaudited pro forma financial statements. The unaudited pro forma statements of consolidated operations have been prepared as if the acquisitions had occurred on January 1 of the respective periods presented, and the pro forma balance sheet has been prepared as if the Mid-America and Seminole acquisitions occurred on June 30, 2002.

EBITDA is defined as net income plus depreciation and amortization and interest expense (net of amortization of loan costs and interest income) less equity in income of unconsolidated affiliates. EBITDA should not be considered an alternative to net income, operating income, cash flow from operations or any other measure of financial performance presented in accordance with generally accepted accounting principles. EBITDA is not intended to represent cash flow. Our management uses EBITDA to assess the viability of projects and to determine overall rates of return on alternative investment opportunities. Because EBITDA excludes some, but not all, items that affect net income and these measures may vary among other companies, the EBITDA data presented above may not be comparable to similarly titled measures of other companies.

ENTERPRISE PRODUCTS PARTNERS L.P.

HISTORICAL PRO FORMA AS ADJUSTED - ---------------------------------- -------------------------- ------ ------------------- SIX MONTHS SIX MONTHS FOR THE YEAR ENDED DECEMBER 31, ENDED JUNE 30, YEAR ENDED ENDED --------------------------- -------- ----------------------- DECEMBER 31, JUNE 30, 1999 2000 2001 2001 2002 2001 2002 --------- - ---------- ---------- ---------- ---------- ------------ ---------- (UNAUDITED) (UNAUDITED) (Dollars in thousands) INCOME STATEMENT DATA: Revenues from consolidated operations...................... $1,332,979 $3,049,020 $3,154,369 $1,795,712 $1,448,311 $3,952,943 $1,608,214 Equity in income of unconsolidated affiliates...................... 13,477 24,119 25,358 11,061 16,295 23,479 16,295 ---------- --------- - ---------- ---------- ---------- ---------- ---------- Total......................... $1,346,456 $3,073,139 $3,179,727 $1,806,773 $1,464,606 $3,976,422 $1,624,509 Costs and expenses: Operating costs and expenses..... $1,201,605 $2,801,060 $2,861,743 $1,629,380 $1,410,044 $3,528,057 $1,487,900 Selling, general and administrative expenses........ 12,500 28,345 30,296 13,905 15,702 64,672 31,888 ---------- --------- - ---------- ---------- ---------- ---------- ---------- Total......................... $1,214,105 $2,829,405 $2,892,039 $1,643,285 $1,425,746 $3,592,729 $1,519,788 Operating income.................. $ 132,351 $ 243,734 $ 287,688 $ 163,488 $ 38,860 $ 383,693 $ 104,721 Other income (expense): Interest expense................. $ (16,439) $ (33,329) $ (52,456) $ (23,318) $ (37,545) $ (118,250) $ (64,156) Interest income from unconsolidated affiliates...... 1,667 1,787 31 31 92 35 92 Dividend income from unconsolidated affiliates...... 3,435 7,091 3,462 1,632 2,196 3,462 2,196 Interest income -- other......... 886 3,748 7,029 5,477 1,575 7,029 1,575 Other income (expense), net...... (379) (272) (1,104) (531) (31) (1,492) (786) ---------- ---------- ------ ---- ---------- ---------- ------- --- ---------- Total......................... $ (10,830) $ (20,975) $ (43,038) $ (16,709) $ (33,713) $ (109,216) $ (61,079) Income before income taxes and minority interest................ $ 121,521 $ 222,759 $ 244,650 $ 146,779 $ 5,147 $ 274,477 $ 43,642 Provision for income taxes......... -- -- -- -- -- (9,513) (5,369) ---------- - --------- ---------- ---------- -- -------- ---------- ---------- Income before minority interest.... $ 121,521 $ 222,759 $ 244,650 $ 146,779 $ 5,147 $ 264,964 $ 38,273 Minority interest.................. (1,226) (2,253) (2,472) (1,478) (30) (7,279) (3,069) ---------- ---------- ---------- ---------- ---------- ---------- ---------- Net income......................... $ 120,295 $ 220,506 $ 242,178 $ 145,301 $ 5,117 $ 257,685 $ 35,204 ========== ========== ========== ========== ========== ========== ========== BASIC EARNINGS PER UNIT(1): Net income per common and subordinated unit................ $ 0.90 $ 1.63 $ 1.70 $ 1.06 $ 0.01 $ 1.69 $ 0.20 ========== ========== ========== ========== ========== ========== ========== DILUTED EARNINGS PER UNIT(1): Net income per common, subordinated and special unit................. $ 0.82 $ 1.32 $ 1.39 $ 0.85 $ 0.01 $ 1.40 $ 0.17 ========== ========== ========== ========== ========== ========== ========== BALANCE SHEET DATA (AT PERIOD END): Total assets...................... $1,494,952 $1,951,368 $2,431,193 $2,441,993 $2,792,376 $4,165,659 Long-term debt.................... 295,000 403,847 855,278 855,608 1,223,552 2,302,117 Partners' equity.................. 789,465 935,959 1,146,922 1,000,704 1,045,846 1,235,347 OTHER FINANCIAL DATA: Cash flows from (used in) operating activities...................... $ 177,953 $ 360,870 $ 283,328 $ 90,595 $ 45,183 Cash flows from (used in) investing activities...................... (271,229) (268,798) (491,213) (397,474) (431,655) Cash flows from (used in) financing activities...................... 74,403 (36,893) 279,547 362,428 257,296 EBITDA............................ 147,050 267,058 320,392 180,349 60,580 $ 452,165 $ 141,490 Distributions received from unconsolidated affiliates........ 6,008 37,267 45,054 13,212 29,133 OPERATING DATA (IN MBPD, EXCEPT AS NOTED): Pipelines: Major NGL and petrochemical pipelines..................... 264 367 454 430 518 1,271 1,339 Natural gas pipelines (BBtu/d)... n/a n/a 1,349 1,263 1,262 1,349 1,262 Fractionation: NGL fractionation................ 184 213 204 184 226 204 226 Isomerization.................... 74 74 80 82 80 80 80 Propylene fractionation.......... 28 33 31 30 55 31 55 Processing -- equity NGL production...................... 67 72 63 54 78 63 78 Octane enhancement................ 5 5 5 4 5 5 5

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(1) Pro forma net income per unit is computed by dividing the limited partners'

interest in net income by the number of units expected to be outstanding at the closing of this offering.

RISK FACTORS

An investment in our common units involves risks. You should carefully consider the following risk factors, together with all of the other information included in, or incorporated by reference into, this prospectus supplement, in evaluating an investment in our common units. If any of the following risks were to occur, our business, financial condition or results of operations could be adversely affected. In that case, the trading price of our common units could decline and you could lose all or part of your investment. For information concerning the other risks related to our business, please read the risk factors included under the caption "Risk Factors" beginning on page 3 of the accompanying prospectus.

RISKS RELATED TO OUR BUSINESS

AFTER INCURRING ADDITIONAL INDEBTEDNESS TO FINANCE THE MID-AMERICA AND SEMINOLE ACQUISITIONS, WE HAVE SUBSTANTIAL LEVERAGE THAT MAY RESTRICT OUR FUTURE FINANCIAL AND OPERATING FLEXIBILITY.

Our leverage is significant in relation to our partners' capital. At June 30, 2002, on a pro forma basis, our total outstanding debt, which represented approximately 69% of our total capitalization, was approximately $2.5 billion. This debt includes the term loan we incurred in July 2002 to finance the Mid-America and Seminole acquisitions, of which $150 million matures on December 31, 2002, an additional $450 million matures on March 31, 2003, and the remaining $600 million matures on July 30, 2003. For a description of our other debt obligations, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Our Debt Obligations" in our Quarterly Report on Form 10-Q for the period ended June 30, 2002.

Debt service obligations, restrictive covenants and maturities resulting from this leverage may adversely affect our ability to finance future operations, pursue acquisitions, fund other capital needs and pay distributions to unitholders, 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. We are prohibited from making cash distributions during an event of default under any of our indebtedness.

We currently expect to meet our anticipated future cash requirements, including scheduled debt repayments, through operating cash flow, proceeds from this offering and the proceeds of one or more future equity or debt offerings. However, 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 which are difficult to predict and beyond our control. If we were 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.

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. The Mid-America and Seminole acquisitions represent significant acquisitions for us and, as a result, we may encounter difficulties integrating these acquisitions with our existing businesses and our other recent acquisitions 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. Any 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.

WE ARE EXPOSED TO PRICING RISKS ASSOCIATED WITH OUR PROCESSING SEGMENT.

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.

THE USE OF MTBE HAS RECENTLY BEEN CHALLENGED ON BOTH THE STATE AND FEDERAL LEVELS.

Our Octane Enhancement segment represents our minority investment in BEF, which currently produces MTBE. The production of MTBE is driven by oxygenated fuels programs enacted 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 also is contemplating a federal ban on MTBE. On April 25, 2002, the Senate approved an energy bill that in part would ban the use of MTBE within four years of enactment and require the use of ethanol as a substitute for MTBE. Several oil companies 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 revenues we derive from our Octane Enhancement segment would be materially reduced or eliminated.

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.

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. We cannot assure you that we have adequately assessed the creditworthiness of our existing or future customers or that there will not be an unanticipated deterioration in their creditworthiness, which could have an adverse impact on us.

RISKS RELATED TO OUR PARTNERSHIP STRUCTURE

CASH DISTRIBUTIONS ARE NOT GUARANTEED AND MAY FLUCTUATE WITH OUR PERFORMANCE AND THE ESTABLISHMENT OF FINANCIAL RESERVES.

Because distributions on our common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. We cannot guarantee that the minimum quarterly distributions will be paid each quarter. The actual amount of cash that is available to be distributed each quarter will depend upon numerous factors, some of which are beyond our control and the control of our general partner. These factors include but are not limited to the following:

- the level of our operating costs;
- the level of competition in our business segments;
- prevailing economic conditions;
- the level of capital expenditures we make;
- the restrictions contained in our debt agreements and our debt service requirements;
- fluctuations in our working capital needs;
- the cost of acquisitions, if any; and
- the amount, if any, of cash reserves established by our general partner, in its discretion.

In addition, cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

COST REIMBURSEMENTS DUE OUR GENERAL PARTNER MAY BE SUBSTANTIAL AND WILL REDUCE OUR CASH AVAILABLE FOR DISTRIBUTION TO YOU.

Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates, including officers and directors of our general partner, for expenses they incur on our behalf. The reimbursement of expenses could adversely affect our ability to pay cash distributions to you. Our general partner has sole discretion to determine the amount of these expenses, subject to an annual limit. In addition, our general partner and its affiliates may provide us other services for which we will be charged fees as determined by our general partner.

OUR GENERAL PARTNER AND ITS AFFILIATES MAY HAVE CONFLICTS WITH OUR PARTNERSHIP.

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

Such conflicts may include, among others, the following:

- decisions of our general partner regarding the amount and timing of cash expenditures, borrowings, issuances of additional units and reserves in any quarter may affect the level of cash available to pay quarterly distributions to unitholders and the general partner;
- under our partnership agreement we reimburse our general partner for the costs of managing and operating our partnership;
- affiliates of our general partner may compete with us in certain circumstances;

- we do not have any employees and we rely solely on employees of the general partner and its affiliates; and

- our general partner generally attempts to avoid liability for partnership obligations and is permitted to protect its assets by the partnership agreement.

YOU MAY NOT BE ABLE TO REMOVE OUR GENERAL PARTNER EVEN IF YOU WISH TO DO SO.

Our general partner manages and operates our partnership. Unlike the holders of common stock in a corporation, you will have only limited voting rights on matters affecting our business. You will have no right to elect the general partner or the directors of the general partner on an annual or other continuing basis. Because the owners of our general partner own more than one-third of our outstanding units, these owners have the practical ability to prevent the removal of our general partner.

In addition, the following provisions of our partnership agreement may discourage a person or group from attempting to remove our general partner or otherwise change our management:

- if holders, including the general partner and its affiliates, of at least 66 2/3% of the units vote to remove the general partner without cause, all remaining subordinated units will automatically convert into common units and will share distributions with the existing common units pro rata, existing arrearages on the common units will be extinguished and the common units will no longer be entitled to arrearages if we fail to pay the minimum quarterly distribution in any quarter. "Cause" means that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud, gross negligence or willful or wanton misconduct in its capacity as our general partner.

- any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter.

- the partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

As a result of these provisions, the price at which the common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

WE MAY ISSUE ADDITIONAL COMMON UNITS WITHOUT YOUR APPROVAL, WHICH WOULD DILUTE YOUR EXISTING OWNERSHIP INTERESTS.

During the subordination period, our general partner may cause us to issue up to 54,550,000 additional common units without your approval. Our general partner may also cause us to issue an unlimited number of additional common units, without your approval, in a number of circumstances, such as:

- the issuance of common units in connection with acquisitions that increase cash flow from operations per unit on a pro forma basis;

- the conversion of subordinated units into common units;

- the conversion of special units into common units;

- the conversion of the general partner interest and the incentive distribution rights into common units as a result of the withdrawal of our general partner; or

- issuances of common units under our long-term incentive plan.

The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- your proportionate ownership interest in us will decrease;

- the amount of cash available for distribution on each unit may decrease;

- since a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by the common unitholders will increase;

- the relative voting strength of each previously outstanding unit may be diminished; and

- the market price of the common units may decline.

After the end of the subordination period, we may issue an unlimited number of limited partner interests of any type without the approval of the unitholders. Our partnership agreement does not give the unitholders the right to approve our issuance of equity securities ranking junior to the common units.

OUR GENERAL PARTNER HAS A LIMITED CALL RIGHT THAT MAY REQUIRE YOU TO SELL YOUR UNITS AT AN UNDESIRABLE TIME OR PRICE.

If at any time our general partner and its affiliates own 85% or more of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price not less than their then current market price. As a result, you may be required to sell your common units at an undesirable time or price and may therefore not receive any return on your investment. You may also incur a tax liability upon a sale of your units.

YOU MAY NOT HAVE LIMITED LIABILITY IF A COURT FINDS THAT LIMITED PARTNER ACTIONS CONSTITUTE CONTROL OF OUR BUSINESS.

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

Under Delaware law, the general partner generally has unlimited liability for the obligations of the partnership, such as its debts and environmental liabilities, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner.

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

TAX RISKS TO COMMON UNITHOLDERS

You are urged to read "Tax Considerations" beginning on page 23 of the accompanying prospectus for a more complete discussion of the following federal income tax risks related to owning and disposing of common units.

THE IRS COULD TREAT US AS A CORPORATION FOR TAX PURPOSES, WHICH WOULD SUBSTANTIALLY REDUCE THE CASH AVAILABLE FOR DISTRIBUTION TO YOU.

The anticipated 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. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

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

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

A SUCCESSFUL IRS CONTEST OF THE FEDERAL INCOME TAX POSITIONS WE TAKE MAY ADVERSELY IMPACT THE MARKET FOR COMMON UNITS, AND THE COSTS OF ANY CONTESTS WILL BE BORNE BY OUR UNITHOLDERS AND OUR GENERAL PARTNER.

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

YOU MAY BE REQUIRED TO PAY TAXES EVEN IF YOU DO NOT RECEIVE ANY CASH DISTRIBUTIONS.

You will be required to pay federal income taxes and, in some cases, state, local and foreign income taxes on your share of our taxable income even if you do not receive any cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from your share of our taxable income.

TAX GAIN OR LOSS ON DISPOSITION OF COMMON UNITS COULD BE DIFFERENT THAN EXPECTED.

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

TAX-EXEMPT ENTITIES, REGULATED INVESTMENT COMPANIES AND FOREIGN PERSONS FACE UNIQUE TAX ISSUES FROM OWNING COMMON UNITS THAT MAY RESULT IN ADVERSE TAX CONSEQUENCES TO THEM.

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

WE ARE REGISTERED AS A TAX SHELTER. THIS MAY INCREASE THE RISK OF AN IRS AUDIT OF US OR A UNITHOLDER.

We are registered with the IRS as a "tax shelter." Our tax shelter registration number is 9906100007. The tax laws require that some types of entities, including some partnerships, register as "tax shelters" in response to the perception that they claim tax benefits that may be unwarranted. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a 1% profits interest in us has very limited rights to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in our unitholders' tax returns and may lead to audits of unitholders' tax returns and adjustments of items unrelated to us. You will bear the cost of any expense incurred in connection with an examination of your personal tax return and indirectly bear a portion of the cost of an audit of us.

WE WILL TREAT EACH PURCHASER OF COMMON UNITS AS HAVING THE SAME TAX BENEFITS WITHOUT REGARD TO THE UNITS PURCHASED. THE IRS MAY CHALLENGE THIS TREATMENT, WHICH COULD ADVERSELY AFFECT THE VALUE OF OUR COMMON UNITS.

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

YOU WILL LIKELY BE SUBJECT TO STATE AND LOCAL TAXES IN STATES WHERE YOU DO NOT LIVE AS A RESULT OF AN INVESTMENT IN OUR COMMON UNITS.

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

USE OF PROCEEDS

We will receive net proceeds of approximately $191.4 million from the sale of the 9,300,000 common units we are offering, including the $3.8 million general partner proportionate contribution to maintain its combined 2% general partner interest. The proceeds are based on an assumed public offering price of $21.00 per common unit after deducting underwriting discounts and commissions and estimated offering expenses payable by us. The underwriters will receive no discount or commission on the sale of up to 1,810,000 common units to our senior management or their affiliates. If the underwriters exercise their over-allotment option in full, we will receive net proceeds of approximately $214.5 million, including the $4.3 million general partner proportionate contribution.

We will use the net proceeds of this offering and our general partner's proportionate capital contribution to repay a portion of the indebtedness outstanding under our $1.2 billion senior unsecured 364-day term loan that we incurred to finance the Mid-America and Seminole acquisitions. At September 26, 2002, the interest rate on the term loan was 3.2%. The term loan matures as follows: $150 million on December 31, 2002, $450 million on March 31, 2003 and $600 million on July 30, 2003. For a description of the term loan, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Our Liquidity and Capital Resources -- Our Debt Obligations." Affiliates of some of the underwriters for this offering, including Lehman Brothers Inc., RBC Dain Rauscher Inc. and Wachovia Securities, Inc., are lenders to us under our term loan and will be partially repaid with the net proceeds from this offering. Please read "Underwriting."

PRICE RANGE OF COMMON UNITS AND DISTRIBUTIONS

On August 31, 2002, we had 131,894,766 common units outstanding, beneficially held by approximately 9,900 holders. The common units are traded on the NYSE under the symbol "EPD."

The following table sets forth, for the periods indicated, the high and low closing sales price ranges for the common units, as reported on the NYSE Composite Transaction Tape, and the amount, record date and payment date of the quarterly cash distributions paid per common unit. The last reported sales price of our common units on the NYSE on September 26, 2002 was $20.92 per common unit.

	PRICE RANGES(1)		CASH DISTRIBUTION HISTORY		
	HIGH	LOW	PER UNIT(1)(2)	RECORD DATE	PAYMENT DATE
2000					
1st Quarter	$10.44	$ 9.13	$0.2500	Apr. 28, 2000	May 10, 2000
2nd Quarter	11.38	9.75	0.2625	Jul. 31, 2000	Aug. 10, 2000
3rd Quarter	14.47	11.07	0.2625	Oct. 31, 2000	Nov. 10, 2000
4th Quarter	15.94	11.75	0.2750	Jan. 31, 2001	Feb. 9, 2001
2001					
1st Quarter	$18.40	$13.25	$0.2750	Apr. 30, 2001	May 10, 2001
2nd Quarter	21.88	16.60	0.2938	Jul. 31, 2001	Aug. 10, 2001
3rd Quarter	24.18	19.75	0.3125	Oct. 31, 2001	Nov. 9, 2001
4th Quarter	26.30	21.80	0.3125	Jan. 31, 2002	Feb. 11, 2002
2002					
1st Quarter	$25.57	$23.13	$0.3350	Apr. 30, 2002	May 10, 2002
2nd Quarter	24.43	16.25	0.3350	Jul. 31, 2002	Aug. 12, 2002
3rd Quarter (through September 26,					

2002)..................................
22.00 16.75

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(1) On February 27, 2002, we announced that our general partner approved a 2-for-1 split for each class of our partnership units. The partnership unit split was accomplished by distributing one additional partnership unit for each partnership unit outstanding on May 15, 2002 to holders of record on April 30, 2002.

(2) On September 12, 2002, we announced that the board of directors of our general partner approved an increase in our quarterly distributions to $0.345 per common unit, or $1.38 per common unit on an annualized basis.

CAPITALIZATION

The following table sets forth our capitalization as of June 30, 2002 on:

- a consolidated historical basis;

- a pro forma basis to give effect to adjustments related to the Mid-America and Seminole acquisitions, including our $1.2 billion senior unsecured 364-day term loan; and

- a pro forma as adjusted basis to give effect to the common units offered by this prospectus supplement, our general partner's proportionate capital contribution and the application of the net proceeds from this offering to repay a portion of indebtedness outstanding under our $1.2 billion senior unsecured 364-day term loan.

You should read our financial statements and notes that are included elsewhere in this prospectus supplement and that are incorporated by reference for additional information about our capital structure.

	AS OF JUNE 30, 2002		
	CONSOLIDATED HISTORICAL	PRO FORMA	PRO FORMA AS ADJUSTED
	(UNAUDITED) (Dollars in thousands)		
Cash and cash equivalents	$ 7,929	$ 19,089	$ 19,089
Short-term debt:			
364-Day Term Loan, due July 2003	$ --	$1,200,000	$1,008,565
Seminole debt, current maturities(1)	--	15,000	15,000
Long-term debt:			
364-Day Credit Facility, due November 2002 (2)	138,000	148,000	148,000
Multi-Year Credit Facility, due November 2005	230,000	230,000	230,000
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	350,000	350,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000	54,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	450,000	450,000
Seminole debt, 6.67% fixed-rate (1)	--	45,000	45,000
Total principal amount	$1,222,000	$2,492,000	$2,300,565
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,895	1,895	1,895
Less unamortized discount:			
Senior Notes A	(99)	(99)	(99)
Senior Notes B	(244)	(244)	(244)
Total debt	$1,223,552	$2,493,552	$2,302,117
Minority interest	10,818	65,146	67,080
Partners' equity:			
Common units	$ 589,504	$ 589,504	$ 777,110
Subordinated units	165,818	165,818	165,818
Special units	296,634	296,634	296,634
Treasury units	(16,736)	(16,736)	(16,736)
General partner interests	10,626	10,626	12,521
Total partners' equity	$1,045,846	$1,045,846	$1,235,347
Total capitalization	$2,280,216	$3,604,544	$3,604,544

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(1) In December 1993, Seminole Pipeline Company issued $75 million of its 6.67% senior unsecured notes in a private placement. These notes are payable at

$15 million annually each December 1 commencing in 2001 through 2005. This debt is being incorporated into our capitalization amounts as a result of our acquisition of a 78% ownership interest in the Seminole pipeline system.

(2) Under the terms of this facility, the Operating Partnership has the option to convert this facility into a term loan due November 15, 2003. Our management intends to refinance this obligation with a similar obligation at or before maturity.

SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following tables set forth for the periods and at the dates indicated selected historical financial and operating data for us, Mid-America and Seminole and selected pro forma financial and operating data for us. The selected historical income statement data for each of the three years in the period ended December 31, 2001 and the selected balance sheet data for each of the two years in the period ended December 31, 2001 are derived from and should be read in conjunction with the audited financial statements for these periods included elsewhere in this prospectus supplement. The selected historical data for the six month periods ending June 30, 2001 and 2002 are derived from and should be read in conjunction with the unaudited financial statements included elsewhere in this prospectus supplement. The tables should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations."

The summary pro forma financial statements of Enterprise Products Partners show the pro forma effect of:

- the Mid-America and Seminole acquisitions including the $1.2 billion senior unsecured 364-day term loan;

- the propylene fractionation and storage business acquired from Diamond-Koch in 2002 and the acquisition of Acadian Gas in 2001;

- the completion of this offering;

- the general partner's proportionate capital contribution; and

- the application of the net proceeds from this offering to repay a portion of indebtedness outstanding under the term loan.

The summary pro forma financial and operating data for the year ended December 31, 2001 and six months ended June 30, 2002 are derived from the unaudited pro forma financial statements. The unaudited pro forma statements of consolidated operations have been prepared as if the acquisitions had occurred on January 1 of the respective periods presented, and the pro forma balance sheet has been prepared as if the Mid-America and Seminole acquisitions occurred on June 30, 2002.

EBITDA is defined as net income plus depreciation and amortization and interest expense (net of amortization of loan costs and interest income) less equity in income of unconsolidated affiliates. EBITDA should not be considered an alternative to net income, operating income, cash flow from operations or any other measure of financial performance presented in accordance with generally accepted accounting principles. EBITDA is not intended to represent cash flow. Our management uses EBITDA to assess the viability of projects and to determine overall rates of return on alternative investment opportunities. Because EBITDA excludes some, but not all, items that affect net income and these measures may vary among other companies, the EBITDA data presented above may not be comparable to similarly titled measures of other companies.

ENTERPRISE PRODUCTS PARTNERS L.P.

HISTORICAL PRO FORMA AS ADJUSTED -

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------------------- SIX MONTHS SIX
MONTHS FOR THE YEAR ENDED DECEMBER
31, ENDED JUNE 30, YEAR ENDED
ENDED ---------------------------
-------- -----------------------
DECEMBER 31, JUNE 30, 1999 2000
2001 2001 2002 2001 2002 ---------
- ---------- ---------- ----------
---------- ------------ ----------
(UNAUDITED) (UNAUDITED) (Dollars
in thousands) INCOME STATEMENT
DATA: Revenues from consolidated
operations......................
$1,332,979 $3,049,020 $3,154,369
$1,795,712 $1,448,311 $3,952,943
$1,608,214 Equity in income of
unconsolidated
affiliates......................
13,477 24,119 25,358 11,061 16,295
23,479 16,295 ---------- ---------
- ---------- ---------- ----------
---------- ----------
Total.........................
$1,346,456 $3,073,139 $3,179,727
$1,806,773 $1,464,606 $3,976,422
$1,624,509 Costs and expenses:
Operating costs and expenses.....
$1,201,605 $2,801,060 $2,861,743
$1,629,380 $1,410,044 $3,528,057
$1,487,900 Selling, general and
administrative expenses........
12,500 28,345 30,296 13,905 15,702
64,672 31,888 ---------- ---------
- ---------- ---------- ----------
---------- ----------
Total.........................
$1,214,105 $2,829,405 $2,892,039
$1,643,285 $1,425,746 $3,592,729
$1,519,788 Operating
income.................. $
132,351 $ 243,734 $ 287,688 $
163,488 $ 38,860 $ 383,693 $
104,721 Other income (expense):
Interest expense.................
$ (16,439) $ (33,329) $ (52,456) $
(23,318) $ (37,545) $ (118,250) $
(64,156) Interest income from
unconsolidated affiliates......
1,667 1,787 31 31 92 35 92
Dividend income from
unconsolidated affiliates......
3,435 7,091 3,462 1,632 2,196
3,462 2,196 Interest income --
other......... 886 3,748 7,029
5,477 1,575 7,029 1,575 Other
income (expense), net...... (379)
(272) (1,104) (531) (31) (1,492)
(786) ---------- ---------- ------
---- ---------- ---------- -------
--- ----------
Total......................... $
(10,830) $ (20,975) $ (43,038) $
(16,709) $ (33,713) $ (109,216) $
(61,079) Income before income
taxes and minority
interest................ $ 121,521
$ 222,759 $ 244,650 $ 146,779 $
5,147 $ 274,477 $ 43,642 Provision
for income taxes......... -- -- --
-- -- (9,513) (5,369) ---------- -
--------- ---------- ---------- --
-------- ---------- ----------
Income before minority

interest.... $ 121,521 $ 222,759 $ 244,650 $ 146,779 $ 5,147 $ 264,964 $ 38,273 Minority interest.................. (1,226) (2,253) (2,472) (1,478) (30) (7,279) (3,069) ---------- ---------- ---------- ---------- ---------- ---------- ---------- Net income......................... $ 120,295 $ 220,506 $ 242,178 $ 145,301 $ 5,117 $ 257,685 $ 35,204 ========== ========== ========== ========== ========== ========== ========== BASIC EARNINGS PER UNIT(1): Net income per common and subordinated unit................ $ 0.90 $ 1.63 $ 1.70 $ 1.06 $ 0.01 $ 1.69 $ 0.20 ========== ========== ========== ========== ========== ========== ========== DILUTED EARNINGS PER UNIT(1): Net income per common, subordinated and special unit................. $ 0.82 $ 1.32 $ 1.39 $ 0.85 $ 0.01 $ 1.40 $ 0.17 ========== ========== ========== ========== ========== ========== ========== BALANCE SHEET DATA (AT PERIOD END): Total assets...................... $1,494,952 $1,951,368 $2,431,193 $2,441,993 $2,792,376 $4,165,659 Long-term debt..................... 295,000 403,847 855,278 855,608 1,223,552 2,302,117 Partners' equity.................. 789,465 935,959 1,146,922 1,000,704 1,045,846 1,235,347 OTHER FINANCIAL DATA: Cash flows from (used in) operating activities...................... $ 177,953 $ 360,870 $ 283,328 $ 90,595 $ 45,183 Cash flows from (used in) investing activities...................... (271,229) (268,798) (491,213) (397,474) (431,655) Cash flows from (used in) financing activities...................... 74,403 (36,893) 279,547 362,428 257,296 EBITDA............................. 147,050 267,058 320,392 180,349 60,580 $ 452,165 $ 141,490 Distributions received from unconsolidated affiliates........ 6,008 37,267 45,054 13,212 29,133 OPERATING DATA (IN MBPD, EXCEPT AS NOTED): Pipelines: Major NGL and petrochemical pipelines..................... 264 367 454 430 518 1,271 1,339 Natural gas pipelines (BBtu/d)... n/a n/a 1,349 1,263 1,262 1,349 1,262 Fractionation: NGL fractionation................ 184 213 204 184 226 204 226 Isomerization.................... 74 74 80 82 80 80 80 Propylene fractionation.......... 28 33 31 30 55 31 55 Processing -- equity NGL production...................... 67 72 63 54 78 63 78 Octane enhancement................. 5 5 5 4 5 5 5

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(1) Pro forma net income per unit is computed by dividing the limited partners'

interest in net income by the number of units expected to be outstanding at the closing of this offering.

MID-AMERICA PIPELINE SYSTEM

	HISTORICAL				
	FOR THE YEAR ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	1999	2000	2001	2001	2002
				(UNAUDITED)	
	(Dollars in thousands)				
INCOME STATEMENT DATA:					
Revenues	$ 190,686	$209,895	$214,518	$102,244	$109,865
Costs and expenses:					
Operating costs and expenses	87,623	105,591	125,349	67,870	45,111
Selling, general and administrative expenses	28,718	29,307	28,364	13,807	15,130
Total	116,341	134,898	153,713	81,677	60,241
Operating income	74,345	74,997	60,805	20,567	49,624
Other income (expense):					
Interest expense	(7,673)	(13,500)	(12,700)	(6,947)	(4,432)
Other, net	822	880	(1,035)	89	(748)
Total	(6,851)	(12,620)	(13,735)	(6,858)	(5,180)
Income before income taxes	67,494	62,377	47,070	13,709	44,444
Provision for income taxes	(23,651)	(22,826)	(17,445)	(4,894)	(16,604)
Net income	$ 43,843	$ 39,551	$ 29,625	$ 8,815	$ 27,840
BALANCE SHEET DATA (AT PERIOD END):					
Total assets	$736,783	$710,835	$681,603		
Long-term debt	90,000	90,000	90,000		
Owner equity	358,184	387,809	426,459		
OTHER FINANCIAL DATA:					
Cash flows from (used in) operating activities	$ 124,367	$ 20,724	$ 17,893	$ 3,402	$ 2,090
Cash flows from (used in) investing activities	(124,367)	(20,724)	(17,893)	(3,402)	(2,090)
EBITDA	94,187	100,877	84,771	33,048	61,167

SEMINOLE PIPELINE COMPANY

	HISTORICAL				
	FOR THE YEAR ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	1999	2000	2001	2001	2002
				(UNAUDITED)	
	(Dollars in thousands)				
INCOME STATEMENT DATA:					
Revenues	$ 64,210	$ 66,609	$ 65,800	$30,880	$ 34,856
Costs and expenses:					
Operating costs and expenses	27,278	37,293	33,539	16,430	17,315
Selling, general and administrative expenses	1,035	1,700	1,535	750	796
Total	28,313	38,993	35,074	17,180	18,111
Operating income	35,897	27,616	30,726	13,700	16,745
Other income (expense):					
Interest expense	(5,002)	(5,003)	(5,160)	(2,450)	(2,006)
Other, net	670	(1,542)	662	(9)	(7)

Total.. (4,332) (6,545) (4,498) (2,459) (2,013) -------- -------- -------- ------- -------- Income before income taxes................................ 31,565 21,071 26,228 11,241 14,732 Provision for income taxes................................. (11,611) (7,590) (9,470) (3,837) (5,347) -------- -------- -------- ------- -------- Net income.. $ 19,954 $ 13,481 $ 16,758 $ 7,404 $ 9,385 ======== ======== ======== ======= ======== BALANCE SHEET DATA (AT PERIOD END): Total assets... $280,940 $282,399 $279,739 Long-term debt, including current maturities............... 75,000 60,000 60,000 Owner equity.. 121,125 133,083 135,768 OTHER FINANCIAL DATA: Cash flows from (used in) operating activities............. $ 19,248 $ 35,046 $ 25,343 $ 8,369 $ 4,096 Cash flows from (used in) investing activities............. (1,946) (795) (565) (286) (2,749) Cash flows from (used in) financing activities............. (24,000) (31,590) (19,800) (2,000) (6,700) EBITDA... 46,692 36,257 41,587 18,786 21,861

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following presentation of Management's Discussion and Analysis of Financial Condition and Results of Operations is not complete and is qualified in its entirety by reference to the information presented in (i) Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2001, (ii) Item 2 of our Quarterly Reports on Form 10-Q for the periods ended March 31, 2002 and June 30, 2002 and (iii) Items 2 and 7 of our Current Report on Form 8-K/A (Amendment No. 1) filed with the Commission on September 26, 2002, which are incorporated by reference herein.

ENTERPRISE PRODUCTS PARTNERS L.P.

INTRODUCTION

We are a leading North American midstream energy company that provides a wide range of services to producers and consumers of natural gas and NGLs. Our asset platform in the Gulf Coast region, combined with our recently acquired Mid-America and Seminole pipeline systems, creates the only integrated North American natural gas and NGL transportation, fractionation, processing, storage and import/export network. We provide integrated services to our customers and generate fee-based cash flow from multiple sources along our natural gas and NGL "value chain." Our business has five reportable segments:

Pipelines. Our Pipelines segment includes approximately 14,000 miles of NGL, petrochemical and natural gas pipelines located primarily in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. This segment also includes our storage and import/export terminalling businesses.

Fractionation. Our Fractionation segment includes eight NGL fractionators, the largest commercial isomerization complex in the United States and four propylene fractionation facilities. NGL fractionators separate mixed NGL streams, which are produced as by-products of natural gas production and crude oil refining, into discrete NGL products: ethane, propane, isobutane, normal butane and natural gasoline. Our isomerization complex converts normal butane into mixed butane, which is subsequently fractionated into normal butane, isobutane and high purity isobutane. Our propylene fractionators separate refinery-sourced propane/propylene mix into propylene, propane and mixed butane.

Processing. Our Processing segment is comprised of our natural gas processing business and related merchant activities. At the core of our natural gas processing business are 13 gas plants, located primarily in south Louisiana, that process raw natural gas into a product that meets pipeline and industry specifications by removing NGLs and impurities. In connection with our processing businesses, we receive a portion of the NGL production from these gas plants. This equity NGL production, together with the NGLs we purchase, supports the merchant activities included in this operating segment.

Octane Enhancement and Other. Our Octane Enhancement segment consists of a 33.3% equity investment in BEF, which owns a facility that produces motor gasoline additives used to enhance octane. Our Other segment consists primarily of fee-based marketing services.

RECENT ACQUISITIONS AND DEVELOPMENT PROJECTS

On July 31, 2002, we completed the acquisition of a 98% indirect ownership interest in the Mid-America pipeline system and a 78% indirect ownership interest in the Seminole pipeline system from Williams for approximately $1.2 billion in cash.

The acquisition of the Mid-America and Seminole pipeline systems was financed with a $1.2 billion senior unsecured 364-day term loan. The net proceeds of this offering will be used to reduce indebtedness outstanding under this term loan. These acquisitions will be reflected in the operating results of our pipeline segment from the date of the acquisitions. We have included in this prospectus supplement financial data for the Mid-America and Seminole pipeline systems. Additionally, we have included a discussion of the results of operations for the Mid-America and Seminole pipeline systems.

Including Mid-America and Seminole, we have completed acquisitions and investments having a combined value of over $3.1 billion during the last three years. These include $1.8 billion in our Pipelines segment, $281 million in our Fractionation segment and $529 million in our Processing segment. These acquisitions and investments are reflected in our historical financial statements commencing as of the date of acquisition. Our key investments and acquisitions include:

- $239 million paid to purchase a controlling interest in a propylene fractionation facility and related assets in Mont Belvieu (2002);

- $130 million paid to purchase storage assets in Mont Belvieu (2002);

- $112 million invested in four Gulf of Mexico natural gas pipeline systems (2001);

- $244 million paid to acquire the Acadian Gas natural gas pipeline network (2001);

- $100 million paid to acquire the Lou-Tex Propylene pipeline (2000);

- $42 million paid to acquire an additional interest in the Mont Belvieu NGL fractionation facility (1999); and

- $529 million paid to acquire TNGL's natural gas processing and NGL businesses (1999).

OUR RESULTS OF OPERATIONS

Our management evaluates segment performance based on 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 interest expense, interest income amounts, dividend income, minority interest, extraordinary charges and other income and expense transactions.

We include equity earnings from unconsolidated affiliates in segment gross operating margin and as a component of revenues. 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 these businesses 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 merchant businesses.

SIX MONTHS ENDED JUNE 30, 2002 COMPARED TO SIX MONTHS ENDED JUNE 30, 2001

Our gross operating margin amounts by segment along with a reconciliation to consolidated operating income were as follows for the periods indicated:

	SIX MONTHS ENDED JUNE 30, 2001	2002
	(IN THOUSANDS)	
Gross operating margin by segment:		
Pipelines	$ 42,819	$64,858
Fractionation	58,471	58,230
Processing	96,510	(34,558)
Octane enhancement	5,402	5,882
Other	946	(1,061)
Total gross operating margin	$204,148	$93,351
Depreciation and amortization	21,822	34,199
Retained lease expense, net	5,320	4,578
Loss (gain) on sale of assets	(387)	12
Selling, general and administrative expenses	13,905	15,702
Consolidated operating income	$163,488	$38,860

Our significant plant production and other volumetric data were as follows for the periods indicated (all data is expressed in MBPD, net, except for natural gas pipelines, which is expressed in BBtu/d, net):

	SIX MONTHS ENDED JUNE 30, 2001	2002
Pipelines		
Major NGL and petrochemical pipelines	430	518
Natural gas pipelines	1,263	1,262
Fractionation		
NGL fractionation	184	226
Isomerization	82	80
Propylene fractionation	30	55
Processing -- equity NGL production	54	78
Octane enhancement	4	5

PIPELINES

Our Pipelines segment recognized $64.9 million in gross operating margin for the first six months of 2002 compared to $42.8 million during the same period in 2001. These results do not include the results of operations related to the Mid-America and Seminole pipeline systems. Net pipeline volumes (on an energy equivalent basis) were 850 MBPD during the 2002 period versus 762 MBPD during the 2001 period. The largest factor in the difference in margin between the two periods is the margin contribution from the storage assets we acquired from Diamond-Koch in January 2002. For the first six months of 2002, these acquired assets added $8.2 million to the gross operating margin of this segment. Other significant year-to-date differences are as follows:

- The 2002 period includes six months of Acadian Gas margins whereas the 2001 period includes only three months (we acquired Acadian Gas on April 1, 2001). The additional quarter's worth of margin in the 2002 period accounts for $4.2 million of the overall increase in segment margin.

- Margin from the Louisiana Pipeline System for the 2002 period increased $5.5 million over the 2001 period primarily due to higher NGL throughput rates. NGL transport volumes increased to 182 MBPD during the first six months of 2002 compared to 119 MBPD during the first six months of 2001. The lower throughput rates during the 2001 period were primarily due to decreased NGL extraction rates at gas processing plants during the first half of 2001 caused by high natural gas prices.

- Equity earnings from EPIK's export terminal increased $2.7 million period-to-period due to a strong export market during the first quarter of 2002. Unusually high domestic prices for propane-related products in the first half of 2001 decreased export opportunities. Product prices during the first quarter of 2002 presented EPIK with a more favorable export environment relative to the first quarter of 2001.

- Margin from our Lou-Tex NGL pipeline system increased $1.9 million period-to-period primarily due to a 13 MBPD increase in transportation volumes.

- Margin from the Lou-Tex Propylene pipeline decreased $2.6 million period-to-period primarily due to lower pipeline throughput rates and higher operating costs. The reduction in volumes is generally attributable to a decline in petrochemical production by shippers.

- Margin from our Houston Ship Channel NGL import facility decreased $1.7 million period-to-period primarily due to a decline in mixed butane imports.

- Margin from our Gulf of Mexico natural gas pipelines decreased $0.5 million period-to-period due to mechanical problems at certain Gulf of Mexico production platforms. These platforms recommenced production in May 2002.

FRACTIONATION

Fractionation gross operating margin was $58.2 million for the first six months of 2002 versus $58.5 million for the first six months of 2001. NGL fractionation margin decreased $2.8 million during the 2002 period when compared to the 2001 period. NGL fractionation net volumes improved to 226 MBPD during the first six months of 2002 versus 184 MBPD for the same period in 2001. NGL fractionation volumes during the first quarter of 2001 were unusually low due to reduced NGL extraction rates at gas processing plants caused by abnormally high natural gas prices (which resulted in a decrease in mixed NGL volumes available for fractionation). The decrease in NGL fractionation margin for the 2002 period is primarily due to the following:

- non-routine maintenance charges at our Mont Belvieu facility in the first quarter of 2002;

- a decrease in tolling fees per gallon at our Mont Belvieu facility due to competition at this industry hub partially offset by a 12 MBPD increase in fractionation volumes; and

- lower in-kind fee revenue at our Norco plant caused by lower NGL prices in 2002 relative to 2001.

The negative factors were partially offset by increased margins at other facilities due to higher processing volumes.

Our isomerization business posted a $9.9 million decrease in margin for the first six months of 2002 when compared to the first six months of 2001. Isomerization volumes decreased to 80 MBPD during the 2002 period versus 82 MBPD during the 2001 period. The decrease in margin is primarily due to lower isomerization fees per gallon. Certain of our isomerization tolling fees are indexed to historical natural gas prices and were positively impacted when the price of natural gas was at historically high levels during the first quarter of 2001 and negatively impacted by lower gas prices in 2002.

For the first six months of 2002, gross operating margin from propylene fractionation was $11.6 million higher than the same period in 2001. The first six months of 2002 includes $10.4 million in margin from the propylene fractionation business we acquired from Diamond-Koch in February 2002. The remainder of the increase in margin is primarily due to lower energy-related costs at our other Mont Belvieu propylene fractionation facilities attributable to lower natural gas prices between periods. Net volumes at our propylene fractionation facilities increased to 55 MBPD for the first six months of 2002 compared to 30 MBPD for the

first six months of 2001. Of the 25 MBPD increase in 2002 volumes, 24 MBPD is attributable to operations acquired from Diamond-Koch.

PROCESSING

Gross operating margin was a loss of $34.6 million for the first six months of 2002 compared to $96.5 million for the first six months of 2001. Our processing operating margin was significantly affected by hedging gains in 2001 and hedging losses in 2002. Eliminating the effects of our hedging program, gross operating margin would have been $16.3 million for the first six months of 2002, compared to $26.2 million for the first six months of 2001.

Our equity NGL production averaged 78 MBPD during the 2002 period versus 54 MBPD during the 2001 period. Equity NGL production during the 2001 period reflected reduced NGL extraction rates at our gas plants resulting from abnormally high natural gas prices (which negatively affected operating costs), particularly during the first quarter of 2001. In general, prices received for our NGL production approximated a weighted-average of 36 CPG for the six months ended June 30, 2002, compared to 56 CPG for the six months ended June 30, 2001. The cost of natural gas averaged $2.86 per MMBtu during the 2002 period versus $5.85 per MMBtu during the 2001 period. Of the $131.1 million decrease in margin between periods, the significant differences are as follows:

- We recorded a loss of $50.9 million from our commodity hedging activities during the first six months of 2002, of which $45.1 million of the loss was recognized during the first quarter of 2002. This compares to $70.3 million of income from such activities during the first six months of 2001. This change in results accounts for $121.2 million of the decrease in margin.

- Prior year margin benefited from unusually strong demand for propane for heating in the first quarter of 2001 and isobutane for refining in the second quarter of 2001. The higher prices caused by the extraordinary demand for these products during the 2001 periods did not recur during the 2002 period.

- Lastly, the decline in commodity hedging results and propane and isobutane demand was offset by a favorable decrease in NGL inventory valuation adjustments between the two quarters and improved processing margins. Processing economics improved period to period as a result of lower natural gas prices during the 2002 period relative to the 2001 period which in turn resulted in higher equity NGL production rates during 2002.

Impact of Commodity Hedging Activities on Our Results of Operations. To manage the risks associated with our Processing segment, from time to time we enter into 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 employ various hedging strategies to mitigate the effects of fluctuating commodity prices (primarily NGL product and natural gas prices) on margins.

One type of hedging strategy, employed in late 2000 and extending through March 2002, was based on the historical relationship between natural gas prices and NGL product 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 merchant activities and the value of equity NGL production. Throughout 2001, this strategy proved successful for us as the price of natural gas declined relative to our fixed positions and was responsible for $101.3 million in income we recorded from commodity hedging activities for that year. In late March 2002, the effectiveness of this hedging strategy deteriorated due to a rapid increase in natural gas prices resulting in losses on our fixed-price natural gas financial instruments which were not offset by increased gas processing margins. As a result, we recognized a loss on these hedging activities of $45.1 million in the first quarter of 2002.

Due to the inherent uncertainty surrounding pricing in the markets, we decided to discontinue the use of this hedging strategy. By late April 2002, we had generally closed out our hedging positions, though not before the value of the portfolio had declined by another $5.7 million. As a result, the total gain from this strategy in fiscal 2001 was approximately $101.3 million and the total loss from this strategy during fiscal 2002 was $50.8 million. Of the $50.8 million in losses from this strategy recorded during 2002, $7.6 million was related to mark-to-market income from these instruments that we recognized in the fourth quarter of 2001. The remaining $43.2 million represents our cash exposure from these losses of which $31.9 million had been paid to counterparties through June 30, 2002. We expect to pay the remaining $11.3 million to counterparties over the remainder of 2002.

Our current hedging strategies primarily cover the price risk associated with certain NGL product inventories and fuel costs. We do not expect any material impact on our liquidity or financial results from the settlement of these commodity financial instruments, which settle primarily in the fourth quarter of 2002 and the first quarter of 2003. The market value of these instruments at June 30, 2002 was a net payable of $0.3 million. From a cash flow sensitivity standpoint, if the commodity prices underlying these instruments were to increase by 10% from the levels they were at on June 30, 2002, the amount we would have to pay counterparties would increase to $0.8 million from $0.3 million. Likewise, if the underlying prices decreased by 10%, we would receive cash of $0.1 million from counterparties as opposed to paying $0.3 million.

OCTANE ENHANCEMENT

Equity earnings from our BEF investment improved to $5.9 million for the first six months of 2002 from $5.4 million for the first six months of 2001. The improvement is primarily due to a 24% increase in MTBE production during the 2002 period due to less maintenance downtime, offset by the impact of lower overall MTBE prices period-to-period which affected margins.

ADDITIONAL MATTERS

Selling, general and administrative expenses. Selling, general and administrative expenses for the first six months of 2002 increased $1.8 million when compared to the first six months of 2001. This increase is primarily due to the additional staff and resources acquired as a result of business acquisitions.

Interest expense. Interest expense increased between the second quarters of 2002 and 2001 and the year-to-date periods primarily due to additional borrowings we made in conjunction with the Diamond-Koch acquisitions and investments in inventories. Also, the first quarter of 2001 includes a $9.3 million benefit related to our interest rate swaps which did not reoccur in 2002.

YEAR ENDED DECEMBER 31, 2001 COMPARED TO YEAR ENDED DECEMBER 31, 2000

Our gross operating margin by segment along with a reconciliation to consolidated operating income for the years presented were as follows:

	FOR YEAR ENDED DECEMBER 31,	
	2000	2001
	(IN THOUSANDS)	
Gross operating margin by segment:		
Pipelines	$ 56,099	$ 96,569
Fractionation	129,376	118,610
Processing	122,240	154,989
Octane enhancement	10,407	5,671
Other	2,493	944
Total gross operating margin	$320,615	$376,783
Depreciation and amortization	35,621	48,775
Retained lease expense, net	10,645	10,414
Loss (gain) on sale of assets	2,270	(390)
Selling, general and administrative expenses	28,345	30,296
Consolidated operating income	$243,734	$287,688

Our significant plant production and other volumetric data for the years presented were as follows (all data is expressed in MBPD, net, except for natural gas pipelines, which is expressed in BBtu/d, net):

	FOR YEAR ENDED DECEMBER 31,	
	2000	2001
Pipelines		
Major NGL and petrochemical pipelines....................	367	454
Natural gas pipelines....................................	n/a	1,349
Fractionation		
NGL fractionation..	213	204
Isomerization..	74	80
Propylene fractionation..................................	33	31
Processing -- equity NGL production......................	72	63
Octane enhancement.......................................	5	5

PIPELINES

Our Pipelines segment posted a gross operating margin of $96.6 million in 2001, compared to $56.1 million in 2000. Of the $40.5 million increase in margin, $20.0 million is attributable to natural gas pipelines acquired in 2001 (i.e., Acadian Gas and the Gulf of Mexico systems). Acadian Gas added $11.8 million in margin with the Gulf of Mexico systems contributing $8.2 million. On a net basis, these pipeline systems transported an average of 1,349 BBtu/d of natural gas.

Net NGL and petrochemical transportation volumes increased to 454 MBPD in 2001 from 367 MBPD in 2000. The majority of this increase is attributable to a rise in commercial butane imports related to higher demand for isobutane production. This activity contributed to a $5.2 million combined increase in margin from our import terminal and HSC pipeline system. Additionally, margin from the Louisiana Pipeline System increased $1.1 million in 2001 due to increased demand for transportation services (with volumes increasing by 23 MBPD in 2001, a 20% increase year-to-year). Also, the Lou-Tex NGL pipeline added $12.2 million to margin during 2001 (construction of this system was completed in the fourth quarter of 2000). This pipeline benefited from the movement of mixed NGLs out of Louisiana to our Mont Belvieu processing facility during 2001.

FRACTIONATION

The gross operating margin from our Fractionation segment decreased to $118.6 million in 2001 from $129.4 million in 2000. NGL fractionation margin for 2001 declined $21.0 million from 2000, primarily as the result of a $19.3 million decrease in "in-kind" fractionation fees at our Norco facility. An in-kind arrangement allows us to receive NGL volumes in lieu of cash fractionation fees. Norco is our only facility with this type of contract. The decline in NGL fractionation margin is related to the NGL volumes received during 2000 having a higher value than those received during 2001. Net volumes at the NGL fractionation facilities decreased to 204 MBPD in 2001 compared to 213 MBPD in 2000. The decrease in throughput is due to lower NGL extraction rates at gas processing facilities in early 2001 (due to the abnormally high cost of natural gas) versus 2000 when the industry was maximizing NGL production. The isomerization business posted an $8.4 million increase in margin for 2001 over 2000 on volumes of 80 MBPD. Isomerization margins were bolstered by increased demand during the second quarter of 2001 for services linked to refinery activities, primarily gasoline blending. 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 July 2000. Net volumes at our propylene fractionation facilities declined slightly to 31 MBPD in 2001 from 33 MBPD in 2000.

PROCESSING

Gross operating margin from our Processing segment was $155.0 million in 2001, up 27% from $122.2 million in 2000. The increase in margin is primarily due to the positive impact of our commodity hedging activities.

2001 was a very challenging year for gas processors industry wide. The volatility of natural gas prices and the depressed nature of NGL prices throughout 2001 created an environment requiring processors to be proactive in meeting the needs of the marketplace. The unusually poor processing economics of the first quarter of 2001 (due to the abnormally high cost of energy relative to the value of our NGL production during that time) yielded to improved market conditions during the second half of 2001 as energy costs moderated. In general, prices received for our NGL production approximated a weighted-average of 43 CPG in 2001 compared to 57 CPG in 2000. In contrast, the cost of natural gas averaged $4.20 per MMBtu in 2001 (peaking at near $10 per MMBtu during the first quarter of 2001) versus $3.84 per MMBtu in 2000.

Equity NGL production averaged 63 MBPD in 2001 compared to 72 MBPD in 2000. The decline in volume is related to the 2000 period reflecting near maximized NGL recoveries supported by strong NGL economics. The 2001 equity NGL production rate reflects less favorable extraction economics (as described above) but is greatly improved relative to the first quarter of 2001's 46 MBPD when energy costs peaked. With the improvement in processing margins in late 2001, we posted equity NGL production of 80 MBPD during the fourth quarter of 2001.

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 recognized a charge to 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.

Our merchant activities benefited from strong demand for propane for heating in the first quarter of 2001 and for isobutane for refining in the second quarter of 2001. Overall, margin from merchant activities improved $9.9 million year-to-year. Processing margin also benefited from the reversal of $9.4 million in excess reserves associated with the gas processing plants.

OCTANE ENHANCEMENT

Equity earnings from our BEF investment declined $4.7 million year-to-year on stable net volumes of 5 MBPD in both periods. The decrease in earnings is primarily attributable to lower MTBE and byproduct prices.

ADDITIONAL MATTERS

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

Interest expense. Interest expense for 2001 increased by $19.1 million over that for 2000. The increase is primarily due to the issuance of our $450 million of public debt in January 2001. The proceeds from this debt were used to acquire our interest in the Stingray, Nautilus, Manta Ray and Nemo pipeline systems from El Paso, to acquire Acadian Gas from Shell and to finance internal growth and other general partnership purposes.

Interest expense for both 2001 and 2000 benefited from income attributable to interest rate hedging activity. During the last two years, we used interest rate swaps in order to effectively convert a portion of our fixed-rate debt into variable-rate debt. With the decline in variable interest rates over the last two years, our swaps provided income to offset fixed-rate-based interest expense. For 2001, we recognized a $13.2 million benefit related to these swaps compared with a $10.0 million benefit recorded in 2000.

During 2001, two of our three swaps that were outstanding at January 1, 2001 were terminated (closing instruments having a notional value of $100 million). One swap was terminated by a counterparty exercising its early termination option while the other counterparty negotiated an early closeout of its position. This left us with one swap outstanding at December 31, 2001 having a notional amount of $54 million. This swap has an early termination option that is exercisable in March 2003.

YEAR ENDED DECEMBER 31, 2000 COMPARED TO YEAR ENDED DECEMBER 31, 1999

Our gross operating margin by segment along with a reconciliation to consolidated operating income for the years presented were as follows:

	FOR YEAR ENDED DECEMBER 31,	
	1999	2000
	(IN THOUSANDS)	
Gross operating margin by segment:		
Pipelines	$ 31,195	$ 56,099
Fractionation	110,424	129,376
Processing	28,485	122,240
Octane enhancement	8,183	10,407
Other	908	2,493
Total gross operating margin	$179,195	$320,615
Depreciation and amortization	23,664	35,621
Retained lease expense, net	10,557	10,645
Loss (gain) on sale of assets	123	2,270
Selling, general and administrative expenses	12,500	28,345
Consolidated operating income	$132,351	$243,734

Our significant plant production and other volumetric data for the years presented were as follows (all data is expressed in MBPD, net, except for natural gas pipelines, which is expressed in BBtu/d, net):

	FOR YEAR ENDED DECEMBER 31,	
	1999	2000
Pipelines		
Major NGL and petrochemical pipelines	264	367
Natural gas pipelines	n/a	n/a
Fractionation		
NGL fractionation	184	213
Isomerization	74	74
Propylene fractionation	28	33
Processing -- equity NGL production	67	72
Octane enhancement	5	5

PIPELINES

The gross operating margin from our Pipelines segment was $56.1 million in 2000 compared to $31.2 million in 1999. Overall NGL and petrochemical volumes increased to 367 MBPD in 2000 from 264 MBPD in 1999. Generally, the $24.9 million increase in margin is attributable to the additional volumes and margins contributed by the TNGL pipeline and storage assets, higher margins from the HSC pipeline system and EPIK due to an increase in export volumes, the margins from the Lou-Tex propylene pipeline that was purchased in March 2000 and margins from the Lou-Tex NGL pipeline, which commenced operations in late November 2000. The growth in export volumes is attributable to the installation of EPIK's new chiller unit that began operations in the fourth quarter of 1999.

FRACTIONATION

The gross operating margin of our Fractionation segment increased to $129.4 million in 2000 from $110.4 million in 1999. The additional margin from the NGL fractionators acquired from Shell in the TNGL acquisition was the primary reason for a $29.7 million increase in NGL fractionation margin in 2000 over 1999. Results for 1999 include five months of margin from the TNGL assets whereas the 2000 period includes twelve months. Net NGL fractionation volume increased to 213 MBPD in 2000 from 184 MBPD in 1999. The increase in net NGL fractionation volume is attributable to higher production rates at our Mont Belvieu NGL fractionator. Our ownership in this facility increased to 62.5% from 37.5% as a result of the July 1999 MBA acquisition.

For 2000, gross operating margin from our isomerization business decreased $7.8 million compared to 1999 primarily due to higher fuel and other operating costs, plus the expenses related to the refurbishment of an isomerization unit. Isomerization volumes were 74 MBPD in both 2000 and 1999. Gross operating margin from propylene fractionation decreased $1.4 million in 2000 from 1999 levels primarily due to higher energy costs. Net volumes at these facilities improved to 33 MBPD in 2000 from 28 MBPD in 1999 due to the startup of the BRPC propylene concentrator in July 2000.

PROCESSING

Our Processing segment generated $122.2 million in gross operating margin during 2000 compared to $28.5 million in 1999. The $93.7 million increase is primarily due to 2000 including twelve months of gas processing (and related merchant activity) margins from the TNGL businesses, whereas 1999 includes only five months. This segment benefited from a stronger NGL pricing environment in 2000 versus 1999 and a rise in equity NGL production from 67 MBPD in 1999 to 72 MBPD in 2000. In general, NGL prices approximated a weighted-average of 57 CPG during 2000 compared to 35 CPG during 1999. The cost of natural gas averaged $3.84 MMBtu during 2000 versus $2.23 per MMBtu during 1999.

OCTANE ENHANCEMENT

The gross operating margin from our Octane Enhancement segment increased to $10.4 million in 2000 from $8.2 million in 1999. Equity earnings for 2000 improved over 1999 levels primarily due to higher than normal MTBE market prices during the second and third quarters of 2000 and lower debt service costs (BEF made its final note payment in May 2000 and, as a result, now owns the facility debt-free). In addition, the 1999 period reflects a $1.5 million non-cash charge related to the write-off of certain start-up expenses. MTBE production, on a net basis, was 5 MBPD in both 2000 and 1999.

ADDITIONAL MATTERS

Selling, general and administrative expenses. These expenses increased to $28.3 million in 2000 from $12.5 million in 1999. The increase is primarily due to expenses related to the additional staff and resources deemed necessary to support our expansion activities resulting from acquisitions and other business development.

Interest expense. Interest expense increased to $33.3 million in 2000 from $16.4 million in 1999. The increase is attributable to a rise in average debt levels from $213 million in 1999 to $408 million in 2000. Debt levels have increased over the previous year primarily due to capital expenditures for assets such as the Lou-Tex propylene and Lou-Tex NGL pipelines and the issuance of $404 million in debt instruments in March 2001. Interest expense for 2000 includes a $10.0 million benefit related to interest rate swaps.

OUR LIQUIDITY AND CAPITAL RESOURCES

Since our operating partnership owns substantially all of our consolidated assets and conducts substantially all of our business and operations, the following discussion of liquidity and capital resources constitutes combined (or consolidated) information for our operating partnership and us. References to partnership equity securities in this discussion pertain to units issued by us. References to public debt pertain to those obligations issued by our operating partnership and guaranteed by us.

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 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 bank credit facilities and the issuance of additional partnership equity and public debt. Our quarterly cash distributions to partners are expected to be funded primarily by current period operating cash flows, or to a lesser extent, temporary borrowings under bank credit facilities or a combination thereof. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

Our operating cash flows primarily reflect the effects of net income adjusted for depreciation and amortization, equity income and cash distributions from unconsolidated affiliates. The net effect of changes in operating accounts is generally the result of timing of sales and purchases near the end of each period. Our cash flows from operations are directly linked to earnings from our business activities. Like our results of operations, 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 and motor gasoline production and as fuel for residential 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.

Certain of our liquidity and capital resource requirements are met using borrowings under bank credit facilities and/or the issuance of additional partnership equity or public debt (separately or in combination). As of June 30, 2002, total borrowing capacity under our revolving bank credit facilities was $500 million of which $132 million was available. We have an effective $500 million universal shelf registration covering the issuance of an unspecified amount of partnership equity or debt securities or a combination thereof. Our plans for permanent financing of the approximately $1.2 billion Mid-America and Seminole acquisitions include the issuance of equity and debt in amounts that are consistent with our objective of maintaining our financial flexibility and investment grade balance sheet.

We have the ability, under certain conditions during the subordination period, to issue an unlimited number of common units to finance acquisitions and capital improvements. The subordination period generally extends until the first day of any quarter beginning after June 30, 2003 when certain financial tests have been satisfied. We have the ability to issue an unlimited number of common units for this type of expenditure if Adjusted Operating Surplus (as defined within our partnership agreement) for the previous four fiscal quarter period prior to 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 previous four fiscal quarters).

For those acquisitions and other transactions that do not qualify under the aforementioned pro forma accretion test, we have 54,550,000 units available (and unreserved) for general partnership purposes during the subordination period. After the subordination period expires, we may issue an unlimited number of units for any partnership purpose.

CREDIT RATINGS

On August 2, 2002, Moody's and S&P changed their ratings outlook regarding our debt securities from "stable" to "negative." The ratings agencies did not take any action to downgrade our ratings; they remain at Baa2 by Moody's and BBB by S&P. Their negative outlook on our ratings reflects the execution risk they see associated with our permanent financing plan for the Mid-America and Seminole acquisitions, which includes the issuance of equity and long-term debt. For a discussion of our debt associated with the Mid-America and Seminole acquisitions, read "-- Our Liquidity and Capital Resources -- Our Debt Obligations." The change in ratings outlook does not translate into any material financial impact on our liquidity. Our management is committed to achieving its goals of permanent financing for the Mid-America and Seminole acquisitions and will actively pursue the appropriate mix and timing of offerings of equity and debt that will maintain our investment grade balance sheet. We maintain regular communications with these rating agencies which independently judge our creditworthiness based on a variety of quantitative and qualitative factors.

CONSOLIDATED CASH FLOWS FOR SIX MONTHS ENDED JUNE 30, 2002 COMPARED TO SIX MONTHS ENDED JUNE 30, 2001

Operating Cash Flows

Cash flow from operating activities was an inflow of $45.2 million for the first six months of 2002 compared to $90.6 million during the same period in 2001. Excluding changes in operating accounts which are generally the result of timing of sales and purchases near the end of each period, adjusted cash flow from operating activities would be an inflow of $77.6 million for the first six months of 2002 versus $121.2 million for the first six months of 2001. Cash flow from operating activities before changes in operating accounts is an important measure of our liquidity. It provides an indication of our success in generating core cash flows from the assets and investments we own or have an interest in. The $43.6 million decrease in adjusted cash flows between the two year-to-date periods is primarily due to net hedging losses in 2002 versus net hedging income in 2001 offset by:

- increased distributions from our unconsolidated affiliates; and

- an increase in operating earnings due to acquisitions.

We recorded $50.9 million in net commodity hedging losses during the first six months of 2002 compared to $70.4 million of income during the first six months of 2001. Of the recorded hedging loss for the 2002 period, we have realized (i.e., paid out to counterparties) $31.9 million of this loss. The difference of $19.0 million between the recorded loss and the realized loss represents the non-cash change in market value of the overall portfolio between December 31, 2001 and June 30, 2002. At June 30, 2002, the market value of the commodity financial instruments that were outstanding was a payable of $11.1 million, which we expect to pay to counterparties over the remainder of the 2002.

We discontinued the hedging strategy underlying the $50.9 million in losses in April 2002. This strategy had helped create essentially all of the $70.3 million in income from commodity hedging activities we recorded during the first six months of 2001, of which $17.9 million had been received from counterparties through June 30, 2001. Please read "-- Our Results of Operations -- Impact of Commodity Hedging Activities on Our Results of Operations."

Investing Cash Flows

During the first six months of 2002, we used $431.7 million in cash to finance investing activities compared to $397.5 million spent during the first six months of 2001. The 2001 period includes $113 million paid to acquire equity interests in several Gulf of Mexico natural gas pipelines from El Paso (our Stingray, Manta Ray, Nautilus and Nemo equity investments) and $244 million paid to acquire Shell's Acadian Gas natural gas pipeline system. The 2002 period reflects $394.8 million in business acquisitions including $368.7 million paid to acquire affiliates of Diamond-Koch's propylene fractionation and NGL and petrochemical storage businesses and $18.0 million paid to Shell representing the final purchase price adjustment relating to the Acadian Gas acquisition.

Financing Cash Flows

Our financing activities generated $257.3 million in cash inflows during the first six months of 2002 compared to $362.4 million during the first six months of 2001. The 2002 period includes $368.0 million in net borrowings under our revolving credit facilities while the 2001 period reflects $449.7 million in proceeds from the issuance of the Senior Notes B, in each case, partially offset by cash distributions to our partners. Cash distributions paid to our partners increased period-to-period primarily due to increases in both the declared quarterly distribution rate and the number of units entitled to receive distributions.

The conversion of 19,000,000 of Shell's non-distribution-bearing special units to distribution-bearing common units on August 1, 2002 will increase distributions paid to partners beginning with the third quarter of 2002 distribution expected to be paid in November 2002.

CONSOLIDATED CASH FLOWS FOR YEAR ENDED DECEMBER 31, 2001 COMPARED TO YEAR ENDED DECEMBER 31, 2000

Operating Cash Flows

Cash flows from operating activities were $283.3 million in 2001 versus $360.9 million in 2000. After adjusting for changes in operating accounts, adjusted cash flow from operating activities would be $320.4 million in 2001 as compared to $289.8 million in 2000. It provides an indication of our success in generating core cash flows from the assets and investments that we own. The $30.7 million increase for 2001 is attributable to our strong earnings as discussed earlier under "Our Results of Operations -- Year Ended December 31, 2001 Compared to Year Ended December 31, 2000."

Investing Cash Flows

During 2001, we used $491.2 million of cash to finance investing activities compared to $268.8 million in 2000. Capital expenditures were $149.9 million during 2001 compared to $243.9 million during 2000. Over the last two years, we have funded $384.3 million in internal growth projects. Of the cumulative $393.8 million spent during 2001 and 2000, $336.2 million is attributable to various pipeline projects, including $99.5 million spent to purchase the Lou-Tex Propylene pipeline (2000), $90.5 million to construct the Lou-Tex NGL pipeline ($83.7 million spent in 2000 with the remainder spent in 2001) and $64.1 million in expansion activities related to our Louisiana Pipeline System (2001). We spent $9.5 million on sustaining capital expenditures during the last two years with $6.0 million in such charges recorded during 2001.

Our investing cash outflows for 2001 include $226 million paid to acquire Acadian Gas from Shell. This amount was subject to certain post-closing adjustments that were completed during the first half of 2002. In addition, our investments in and advances to unconsolidated affiliates increased $84.7 million in 2001 due to the $112.0 million paid to purchase equity interests in several Gulf of Mexico natural gas pipeline systems from El Paso.

Financing Cash Flows

Our financing activities generated $279.5 million of cash receipts during 2001 compared to cash payments of $36.9 million in 2000. Cash flows from financing activities are primarily affected by repayments of debt, borrowings under debt agreements and distributions to partners. Cash flow from financing activities in 2001 includes proceeds from the $450 million Senior Notes B issued in January 2001 whereas the 2000 period includes proceeds from the $350 million Senior Notes A and $54 million MBFC Loan and the associated repayments on various bank credit facilities.

Cash distributions to partners and the minority interest increased to $166.0 million in 2001 from $141.0 million in 2000 primarily due to (i) increases in the quarterly distribution rate and (ii) the conversion of 5.0 million of Shell's special units into common units. Our cash distribution policy has allowed us to retain a significant amount of cash flow for reinvestment in the growth of the business. Over the last two years, we have retained approximately $275.0 million to fund expansions and business acquisitions. We believe that our cash distribution policy provides the partnership with financial flexibility in executing its growth strategy.

At December 31, 2001, we had $5.8 million in restricted cash required by the NYMEX commodity exchange to facilitate financial instrument and physical purchase transactions. This amount can fluctuate over time depending on the physical volumes underlying the contracts, market price of the commodity and type of transactions executed. During 2001, our restricted cash balance required by the exchange varied, reaching a peak of $13.4 million in July.

CONSOLIDATED CASH FLOWS FOR YEAR ENDED DECEMBER 31, 2000 COMPARED TO YEAR ENDED DECEMBER 31, 1999

Operating Cash Flows

Cash flows from operating activities were $360.9 million in 2000 compared to $177.9 million in 1999. After adjusting for changes in operating accounts, adjusted cash flow from operating activities increased $139.8 million to $289.8 million in 2000 compared to $150.0 million in 1999. The $139.8 million increase in adjusted cash flow from operating activities between periods is primarily due to the impact of the TNGL acquisition.

Investing Cash Flows

We invested $268.8 million during 2000 (primarily in internal growth projects) compared to $271.2 million spent during 1999 (primarily for acquisitions). Fiscal 1999 reflects $208.1 million in net cash payments resulting from the TNGL and MBA acquisitions. Our capital expenditures increased substantially in 2000 over 1999 primarily due to the purchase of the Lou-Tex Propylene pipeline ($99.5 million) and construction costs related to the Lou-Tex NGL pipeline ($83.7 million).

Investments in and advances to unconsolidated affiliates during 1999 include our share of costs ($38.2 million) to complete construction and commence operations of the BRF facility and Wilprise and Tri-States pipelines. Our 2000 expenditures include $19.4 million paid to purchase an additional 8.4% interest in the Dixie pipeline. The 1999 and 2000 amounts also include a combined $26.2 million in costs to construct the BRPC facility, which was completed in July 2000.

Financing Cash Flows

Our financing activities resulted in net cash payments of $36.9 million in 2000 versus net cash receipts of $74.4 million in 1999. Fiscal 2000 includes proceeds from the issuance of Senior Notes A and the MBFC Loan and the associated repayments on various bank credit facilities. Financing activities in 1999 include the borrowings under bank credit facilities to finance the TNGL and MBA acquisitions. Distributions to partners and the minority interest increased to $141.0 million in 2000 compared to $112.9 million in 1999 primarily due to increases in the quarterly distribution rate. Lastly, we repurchased and retired 28,400 common units during 2000 under our buy-back program at a cost of $0.8 million.

CASH REQUIREMENTS FOR FUTURE GROWTH

Future Acquisitions

We are committed to the long-term growth and viability of our partnership. 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 natural gas industry in which we operate. We forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar disposal options. Our management continues to analyze potential acquisitions, joint ventures or similar transactions with businesses that operate in complementary markets and geographic regions. We believe that our partnership is positioned to continue to grow through acquisitions that will expand its platform of assets and through internal growth projects.

So far in fiscal 2002, we have invested $1.6 billion in business acquisitions and internal growth projects, including $1.2 billion for the interests in Mid-America and Seminole we purchased from Williams in July 2002, $239.0 million for the Mont Belvieu propylene fractionation assets we purchased from Diamond-Koch in February 2002 and $129.6 million for the Mont Belvieu NGL and petrochemical storage assets we purchased from Diamond-Koch in January 2002. Of the $1.6 billion in business acquisitions and internal growth projects we have completed thus far in 2002, we have borrowed approximately $1.5 billion of the funds required. This will translate into additional debt service costs during 2002.

The $1.2 billion we borrowed to effect the Mid-America and Seminole acquisitions was in the form of a senior unsecured 364-day term loan. The loan will mature as follows: $150 million due on December 31, 2002, $450 million on March 31, 2003 and $600 million on July 30, 2003. Our plans for permanent financing of these acquisitions include the issuance of equity and debt in amounts that are consistent with our objective of maintaining our financial flexibility and investment grade balance sheet. We will use the net proceeds from this offering to retire a portion of the indebtedness outstanding under our $1.2 billion senior unsecured 364-day term loan. Please read "Use of Proceeds."

Future Distributions

Our management's goal is to increase the distribution rate to our investors by at least 10% annually. For the fourth quarter of 2001, the declared annual rate was $1.25 per common unit (on a post-split basis). In the first quarter of 2002, the declared annual rate was raised to $1.34 per common unit. On September 12, 2002, we announced that the board of directors of our general partner approved an increase in our quarterly distribution rate to our partners from $0.335 per unit to $0.345 per unit, or $1.38 on an annualized basis. Based on the number of distribution-bearing units projected to be outstanding at the end of 2002 (not including the effect of any potential equity offerings), we project that this increase would translate into cash distributions to partners increasing by approximately $48 million over the amounts paid during 2001. The number of distribution-bearing units projected to be outstanding at the end of 2002 includes the August 2002 conversion of 19.0 million non-distribution-bearing special units owned by Shell into an equal amount of distribution-bearing common units.

Our distribution rate is supported by prospective and historical cumulative cash flow since our initial public offering in July 1998. From our initial public offering through August 2002, we generated $849.6 million in cash that was available for distribution to unitholders, of which $573.3 million was paid to unitholders (including the second quarter of 2002 distribution paid on August 12, 2002). Our policy has been to retain and invest the difference of $276.3 million (the "excess cash flow") in capital projects that we anticipate will be accretive in terms of cash flow to our unitholders over time. This policy has helped us to maintain a strong financial presence in the markets we serve by minimizing debt and using the excess cash flow to expand the partnership through internal growth and acquisitions.

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 bank credit facilities for the purpose of paying distributions until the full cash flow impact of our operations is realized.

Capital Spending

At June 30, 2002, we had $6.8 million in outstanding purchase commitments attributable to capital projects. Of this amount, $5.1 million is related to the construction of assets that will be recorded as property, plant and equipment and $1.7 million is associated with capital projects of our unconsolidated affiliates which will be recorded as additional investments.

During the first six months of 2002, our capital expenditures were $26.8 million, excluding acquisitions. For the remainder of 2002, we expect our capital spending to approximate $8.1 million of which $5.7 million is forecasted for our Pipelines segment. Our unconsolidated affiliates forecast a combined $13.9 million in capital expenditures during the remainder of 2002 of which we expect our share to be approximately $4.8 million, the majority of which relate to expansion projects on our Gulf of Mexico natural gas pipeline systems. These outlays will be recorded as additional investments in unconsolidated affiliates.

New environmental regulations in the state of Texas may necessitate extensive redesign and modification of our Mont Belvieu facilities to achieve the air emissions reductions needed for federal Clean Air Act compliance in the Houston-Galveston, Texas area. The technical practicality and economic reasonableness of these regulations have been challenged under state law in litigation filed on January 19, 2001, against the Texas Commission on Environmental Quality (formerly named the Texas Natural Resource Conservation Commission) and its principal officials in the District Court of Travis County, Texas, by a coalition of major Houston-Galveston area industries, including our company. In June 2002, the TCEQ proposed a rule that would mitigate certain aspects of these requirements. This rule is scheduled to be finalized in December 2002. Until this rulemaking is finalized and the associated litigation is resolved, the precise level of technology to be employed and the cost for modifying the facilities to achieve the required amount of reductions cannot be determined. Regardless of the outcome of the pending rulemaking and the associated litigation, 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 2002 to begin making modifications 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.

OUR DEBT OBLIGATIONS

For a detailed discussion of our debt obligations, please read Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Our Liquidity and Capital Resources" in our Annual Report on Form 10-K for the year ended December 31, 2001 and Item 2 "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Our Liquidity and Capital Resources" in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2002.

Debt Associated With Mid-America and Seminole Acquisitions. We entered into a $1.2 billion senior unsecured 364-day term loan to fund the acquisition of the Mid-America and Seminole pipeline systems from Williams on July 31, 2002. The lenders under this facility are Wachovia Bank, National Association, Lehman Brothers Bank, FSB, Lehman Commercial Paper Inc. and Royal Bank of Canada. The term loan currently bears interest at 3.2% and will generally bear interest at either:

- the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent; or

- a Eurodollar rate, with any rate in effect being increased by an appropriate applicable margin.

The $1.2 billion senior unsecured 364-day term loan contains various affirmative and negative covenants applicable to our operating partnership similar to those required under our Multi-Year and 364-Day Credit Facility agreements. The term loan is guaranteed by us through an unsecured guarantee. The term loan matures as follows: $150 million on December 31, 2002, $450 million on March 31, 2003 and $600 million on July 30, 2003.

On August 1, 2002, Seminole had $60 million in senior unsecured notes due in December 2005. The principal amount of these notes amortize by $15 million each December 1 through 2005. In accordance with generally accepted accounting principles, this debt will be consolidated on our balance sheet because of our 78% indirect ownership interest in the Seminole pipeline system.

OUR ACCOUNTING POLICIES

For a discussion of our accounting policies, the impact of recent accounting developments and uncertainties in our investment in BEF, see Item 2 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Quarterly Report on Form 10-Q for the period ended June 30, 2002 and Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2001.

RELATED PARTY TRANSACTIONS

For a more detailed discussion of our related party transactions, please read Item 2 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Quarterly Report on Form 10-Q for the period ended June 30, 2002 and Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2001.

RELATIONSHIP WITH EPCO AND ITS AFFILIATES

We have an extensive and ongoing relationship with EPCO, which owns 65% of our general partner. EPCO is majority-owned and controlled by Dan L. Duncan, Chairman of the Board and a Director of our 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 executives and other officers of our general partner are employees of EPCO. The principal business activity of our general partner is to act as our managing partner. EPCO performs our management, administrative and operating functions pursuant to the terms of the EPCO agreement (in effect since July 1998). For additional information regarding the EPCO agreement and other related party transactions with EPCO or its affiliates, please refer to Item 13 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2001.

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 Randa D. Williams, a director of our general partner. In addition, EPCO and Dan Duncan, LLC collectively own 70% of our general partner which in turn owns a combined 2% interest in our company.

In addition, trust affiliates of EPCO (Enterprise Products 1998 Unit Option Plan Trust and the Enterprise Products 2000 Rabbi Trust) purchase common units for the purpose of granting options to certain directors of our general partner, EPCO management and certain key employees. During 2001, these trusts purchased 423,036 common units on the open market or through privately negotiated transactions. At December 31, 2001, these trusts owned a total of 2,923,036 common units. In November 2001, EPCO directly purchased 1,000,000 common units at market prices for $22.6 million on behalf of a key executive and director of our general partner.

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.

As a result of our company satisfying certain financial tests, 10,704,936 (or 25%) of EPCO's subordinated units converted to common units on May 1, 2002. Should the financial criteria continue to be satisfied through the first quarter of 2003, an additional 25% of the subordinated units would convert to common units on May 1, 2003. The remaining 50% of subordinated units would convert on August 1, 2003 should the balance of the conversion requirements be met. Subordinated units have no voting rights until converted to common units. The conversion(s) will have no impact upon our earnings per unit since the subordinated units are already included in both the basic and diluted calculations.

RELATIONSHIP WITH SHELL

We have an extensive relationship with Shell. Following this offering, Shell will own approximately 21.9% of our limited partner units and 30.0% of our general partner. Currently, three members of the board of directors of our general partner (J.R. Eagan, J.A. Berget and Augustus Y. Noojin, III) are employees of Shell.

Shell is a significant customer of our Processing segment. We have the option to process Shell's current and future natural gas production from the Gulf of Mexico under a 20-year contract. Apart from operating expenses arising from the Shell Processing Agreement, we also sell NGL and petrochemical products to Shell. During 2001, Shell generated $333.3 million, or 10.5%, of our revenues.

Shell owns a 45.4% equity interest in one of our propylene fractionators at our Mont Belvieu complex. We lease Shell's interest in this facility under a long-term agreement. We have a long-term contract to provide Shell with propylene from this facility. We have supplied Shell with propylene since our first propylene fractionator was constructed in 1979.

In April 2000, we acquired the Lou-Tex propylene pipeline system and an underground storage facility from Shell for $100 million in a negotiated transaction that was approved by the Board of Directors of our general partner, with the three Shell representatives abstaining. As part of the transaction, we entered into a 20-year agreement to deliver propylene from Louisiana to Shell's facilities on the Texas Gulf Coast.

In January 2001, we acquired ownership interests in the Nautilus, Manta Ray, Nemo, Stingray and Triton natural gas pipeline systems in the Gulf of Mexico from affiliates of El Paso. Shell owns equity interests of 50%, 50%, 66%, 50% and 50%, respectively, in these pipeline systems. Shell has responsibilities for the commercial and physical management of these pipeline systems.

In April 2001, we acquired Acadian Gas from Shell for approximately $244 million in a negotiated transaction (through a bidding process) that was approved by the board of directors of our general partner, with the three Shell representatives abstaining.

In accordance with existing agreements with Shell, 19 million of Shell's non-distribution bearing special units converted to distribution bearing common units on a one-for-one basis on August 1, 2002. These special units were issued to Shell over a period of time as assets acquired from Shell in the TNGL acquisition in 1999 achieved performance targets established at the time of the acquisition. The remaining 10 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.

MID-AMERICA AND SEMINOLE RESULTS OF OPERATIONS

The following discussion relates to the results of operations of the Mid-America and Seminole pipeline systems, which we acquired from Williams in July 2002. For additional information relating to the financial condition and results of operations of Mid-America and Seminole, please read the Mid-America Pipeline System Financial Statements and the related notes beginning on page F-77 and the Seminole Pipeline Company Financial Statements and related notes beginning on page F-87.

MID-AMERICA PIPELINE SYSTEM

Mid-America's primary business focus is to provide NGL transportation services to customers (or shippers) on a fee (or tariff) basis. As such, Mid-America's results of operations are generally dependent upon the volume of NGLs transported and the level of fees charged to shippers. Mid-America is an interstate common carrier pipeline subject to regulation by the FERC and some state and local governmental agencies. As an interstate common carrier, Mid-America provides service to any shipper who requests transportation services, provided that products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. Mid-America is required to maintain tariffs on file with the FERC that set forth the rates it can charge for providing transportation services as well as the rules and regulations governing these services. Mid-America's intrastate transportation services are generally under the regulation of the state in which the NGL movement occurs.

The volume of NGLs available for transportation on the Mid-America pipeline system is driven by natural gas and related NGL production from the natural gas supply basins it serves. Mid-America has connections extending into several natural gas supply basins throughout North America, including the Rocky Mountain Overthrust, the San Juan and Permian basin, the Mid-Continent region and, through third-party pipeline connections, north into Canada's Western Sedimentary basin. The volume of NGLs available for transportation on the Mid-America pipeline system can be affected by NGL extraction rates at natural gas processing facilities, which in turn are affected by the relationship between the market prices of natural gas and NGLs. During periods in which the relative economic value of the mixed NGLs extracted by gas processing plants is less than the costs associated with these activities, gas processors will reduce the volume of NGLs they produce, which will subsequently reduce the quantity of NGLs available for transportation on Mid-America. Approximately 20 natural gas processing plants in Wyoming, Utah and Colorado feed NGLs into Mid-America for delivery to several destinations. In addition, Mid-America's volumes are generally affected by seasonal changes in propane demand. Overall, NGL transportation volumes tend to be higher in the October through March timeframe due to the increased use of propane for heating. During 2001, approximately 63% of Mid-America's revenues were derived from five major companies in the NGL industry: BP, Burlington, Duke, Equistar and Williams.

The following table reflects Mid-America's revenues, costs and expenses, operating income and gross operating margin for each of the three years ended December 31, 2001 and the six month periods ended June 30, 2001 and 2002. The table also includes average NGL transportation volumes for each of the periods indicated.

	FOR THE YEAR ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	1999	2000	2001	2001	2002
	(DOLLARS IN THOUSANDS)			(UNAUDITED)	
Revenues	$190,686	$209,895	$214,518	$102,244	$109,865
Costs and expenses	116,341	134,898	153,713	81,677	60,241
Operating income	74,345	74,997	60,805	20,567	49,624
Gross operating margin	122,083	129,304	114,170	46,766	77,045
NGL transportation volumes (MBPD)	634	637	641	617	631

Immediately prior to our acquisition, Mid-America extinguished all of its debt, thereby eliminating interest expense associated with these amounts on a going-forward basis.

SIX MONTHS ENDED JUNE 30, 2002 COMPARED TO SIX MONTHS ENDED JUNE 30, 2001

Revenues increased to $109.9 million in 2002 from $102.2 million in 2001 primarily due to an increase in transportation volumes from 617 MBPD in 2001 to 631 MBPD in 2002. Transportation volumes during the first six months of 2001 reflected decreased NGL extraction rates at gas processing facilities served by Mid-America. The decrease in NGL extraction rates was primarily due to abnormally high natural gas prices relative to the price of NGLs during the period.

Mid-America's costs and expenses decreased by $21.4 million for the first six months of 2002 as compared to the first six months of 2001, primarily due to the following:

- The value of Mid-America's working inventory was written down by $12.9 million during the first six months of 2001 due to a decrease in NGL and petrochemical prices during the period relative to its average historical carrying values of these products.

- Mid-America's fuel and power costs for the first six months of 2002 were $5.8 million lower than those recorded during the first six months of 2001. The lower expense is primarily due to a decrease in the price of natural gas (which is a significant component of energy-related costs) between the two periods.

Operating income increased $29.1 million for the first six months of 2002 as compared to the first six months of 2001 primarily as a result of the items discussed above. Gross operating margin increased $30.2 million to $77.0 million in 2002 from $46.8 million in 2001 for similar reasons.

YEAR ENDED DECEMBER 31, 2001 COMPARED TO YEAR ENDED DECEMBER 31, 2000

Revenues increased to $214.5 million in 2001 from $209.9 million in 2000 primarily due to an increase in transportation volumes from 637 MBPD in 2000 to 641 MBPD in 2001. Transportation volumes in 2001 increased relative to 2000 despite the decrease in NGL extraction rates mentioned earlier. Costs and expenses increased $18.8 million in 2001 primarily due to a decrease in the value of Mid-America's working inventory relative to its average historical carrying value.

Operating income decreased $14.2 million for the year ended December 31, 2001 as compared to the year ended December 31, 2000 primarily as the result of the items discussed above. Gross operating margin decreased $15.1 million to $114.2 million in 2001 from $129.3 million in 2000 for similar reasons.

YEAR ENDED DECEMBER 31, 2000 COMPARED TO YEAR ENDED DECEMBER 31, 1999

Revenues increased to $209.9 million in 2000 from $190.7 million in 1999 primarily due to an increase in transportation volumes from 634 MBPD in 1999 to 637 MBPD in 2000. The increase in transportation volumes is primarily due to Mid-America's Rocky Mountain pipeline, which was placed in service in late 1999. Costs and expenses increased $18.6 million for the year ended December 31, 2000 as compared to the year ended December 31, 1999, primarily as the result of the addition of operating expenses associated with the Rocky Mountain pipeline and higher overall fuel and power costs.

Operating income increased $0.7 million year-to-year primarily as the result of the items discussed above. Gross operating margin increased $7.2 million to $129.3 million in 2000 from $122.1 million in 1999 for similar reasons. The $6.5 million difference between gross operating margin and operating income is primarily due to the additional depreciation expense recorded in 2000 associated with the Rocky Mountain pipeline.

LIQUIDITY AND CASH FLOW

Mid-America's primary cash requirements, in addition to normal operating expenses, are for capital expenditures and cash dividends to its owner. Historically, Mid-America's revenues have been sufficient to meet its cash requirements for operating expenses and to fund debt service requirements. Mid-America's capital expenditures during the three years ended December 31, 2001 were $176.8 million, of which $121.4 million was associated with the Rocky Mountain pipeline completed in 1999.

SEMINOLE PIPELINE COMPANY

Seminole pipeline system's primary business is providing NGL transportation services to customers (shippers) on a fee (or tariff) basis. As such, Seminole's results of operations are generally dependent upon the volume of NGLs transported and the level of fees charged to customers. Seminole's pipeline system is an intrastate common carrier pipeline subject to regulation by the FERC and some state and local governmental agencies. As a common carrier, Seminole provides service to any shipper who requests transportation services, provided that such products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. Seminole is required to maintain tariffs on file with the FERC that set forth the rates it can charge for providing transportation services as well as the rules and regulations governing these services.

The volume of NGLs available for transportation on Seminole is primarily dependent on demand for mixed NGLs and NGL products from petrochemical plants in the Houston, Texas vicinity that manufacture plastics and other petrochemical products. Volumes transported on the Seminole system originate primarily as injections from the Mid-America pipeline system (on a joint tarriff basis). As such, a significant decline in the volumes transported by Mid-America to the Hobbs hub will have a similar impact on Seminole's transportation volumes and margins.

NGL transportation volumes on the Seminole pipeline do not exhibit a significant degree of seasonality. Throughput rates are principally driven by downstream demand from petrochemical plants which can be affected by general economic conditions and other matters. From the standpoint of competition, Seminole does not have any direct competitors for the volumes it transports since these volumes are primarily dedications from Mid-America. During 2001, approximately 77% of Seminole's revenues were derived from five major companies in the NGL industry: BP, Burlington, ConocoPhillips, Duke and Williams.

The following table reflects Seminole's revenues, costs and expenses, operating income and gross operating margin for each of the three years ended December 31, 2001 and the six month periods ended

June 30, 2001 and 2002. The table also includes average NGL transportation volumes (in MBPD) for each of the periods indicated.

	FOR THE YEAR ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	1999	2000	2001	2001	2002
	(DOLLARS IN THOUSANDS)			(UNAUDITED)	
Revenues	$64,210	$66,609	$65,800	$30,880	$34,856
Costs and expenses	28,313	38,993	35,074	17,180	18,111
Operating income	35,897	27,616	30,726	13,700	16,745
Gross operating margin	47,057	39,499	42,460	19,545	22,664
NGL transportation volumes (in MBPD)	245	245	241	230	259

SIX MONTHS ENDED JUNE 30, 2002 COMPARED TO SIX MONTHS ENDED JUNE 30, 2001

Revenues increased to $34.9 million in 2002 from $30.9 million in 2001 primarily due to an increase in transportation volumes from 230 MBPD in 2001 to 259 MBPD in 2002. NGL volumes available for transportation were lower in 2001 due to decreased NGL extraction rates at gas plants during the first quarter of 2001 resulting from abnormally high natural gas prices. Costs and expenses increased $0.9 million for the year primarily as the result of increased offloading charges. Operating income and gross operating margin increased $3.0 million and $3.1 million, respectively, in 2002 as compared to 2001, primarily due to the increased throughput rates.

YEAR ENDED DECEMBER 31, 2001 COMPARED TO YEAR ENDED DECEMBER 31, 2000

Revenues decreased to $65.8 million in 2001 from $66.6 million in 2000 primarily due to a decrease in transportation volumes from 245 MBPD in 2000 to 241 MBPD in 2001. As noted above, 2001 volumes were affected by the decrease in NGL extraction rates throughout the industry. Costs and expenses decreased to $35.1 million in 2001 from $39.0 million in 2000 primarily due to decreases in fuel and power costs of $1.8 million and property taxes of $1.9 million. Operating income and gross operating margin increased $3.1 million and $3.0 million, respectively, primarily due to the lower operating expenses partially offset by decreased transportation volumes.

YEAR ENDED DECEMBER 31, 2000 COMPARED TO YEAR ENDED DECEMBER 31, 1999

Revenues increased to $66.6 million in 2000 from $64.2 million in 1999. Transportation volumes were 245 MBPD for both years. Costs and expenses increased $10.7 million to $39.0 million in 2000 from $28.3 million in 1999 primarily due to increases in fuel and power costs of $4.6 million and property taxes of $2.5 million. Operating income and gross operating margin decreased by $8.3 million and $7.6 million, respectively, primarily due to the higher operating expenses.

LIQUIDITY AND CASH FLOW

Seminole's primary cash requirements, in addition to normal operating expenses and debt service, are for capital expenditures and dividends to its stockholders. Historically, Seminole's revenues have been sufficient to meet its cash requirements.

In December 1993, Seminole issued $75 million of 6.67% senior unsecured notes in a private placement. The principal amount of these notes amortizes at a rate of $15 million annually commencing on December 1, 2001 through 2005. Interest is paid semi-annually on June 1 and December 1. Seminole was in compliance with its covenants with respect to the notes at December 31, 2001 and June 30, 2002.

OUR OPERATIONS

We are a leading North American midstream energy company that provides a wide range of services to producers and consumers of natural gas and NGLs. Our asset platform in the Gulf Coast region, combined with our recently acquired Mid-America and Seminole pipeline systems, creates the only integrated North American natural gas and NGL transportation, fractionation, processing, storage and import/export network. We provide integrated services to our suppliers and customers and generate fee-based cash flow from multiple sources along our natural gas and NGL "value chain." 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 delivery to our industrial, utility and municipal customers;

- transportation of mixed NGLs to fractionation facilities by pipeline;

- fractionation 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 on a merchant basis.

We have five reportable business segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. Pipelines consists of our natural gas, NGL and petrochemical pipeline systems, storage and import/export terminaling businesses. Fractionation includes our NGL fractionation, isomerization and propylene fractionation facilities. Processing includes our natural gas processing business and NGL merchant activities. Octane Enhancement represents our minority interest in a facility that produces motor gasoline additives to enhance octane. Other consists primarily of fee-based marketing services.

RECENT SIGNIFICANT ACQUISITIONS

Acquisitions of Mid-America and Seminole Pipeline Systems. On July 31, 2002, we completed the acquisition of the Mid-America and Seminole pipeline systems from Williams for approximately $1.2 billion in cash. The acquisition included:

- the purchase of a 98% ownership interest in Mapletree, LLC, which owns 100% of the Mid-America pipeline system and indirectly owns 16 propane terminals and over 1.5 million barrels of storage capacity; and

- the purchase of a 98% ownership interest in E-Oaktree, LLC, which owns an 80% equity interest in the Seminole pipeline system.

Mid-America is a 7,226-mile NGL pipeline system connecting the Hobbs hub located on the Texas-New Mexico border with supply regions in the Rocky Mountains and with supply regions and markets in the Midwest. The Mid-America pipeline system is comprised of three major segments: the Conway North pipeline, the Conway South pipeline and the Rocky Mountain pipeline. In 2001, average transportation volumes on the Mid-America pipeline system were approximately 641 MBPD. Seminole 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 the Permian basin to Mont Belvieu, Texas. In 2001, average transportation volumes on the Seminole pipeline system were approximately 241 MBPD, of which approximately 32% of Seminole's volumes in 2001 were transported to our Mont Belvieu facilities for fractionation, storage and distribution. Major customers utilizing the Mid-America and Seminole pipeline systems include BP, Burlington, ConocoPhillips, Duke, Equistar and Williams.

The acquisition of the Mid-America and Seminole pipeline systems 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. In addition to access to supply, the combination of these assets with our existing assets creates a significant link between Mont Belvieu, Texas and Conway, Kansas, the two largest NGL hubs in the United States, and provides additional access to new end markets for NGL products. The Conway South segment of the Mid-America pipeline system connects the Conway hub with refineries in Kansas and transports mixed NGLs from Conway to Hobbs and from Hobbs to Mont Belvieu. The 2,740-mile Conway North pipeline links the market hub in Conway with petrochemical and refining customers and propane markets in the upper Midwest.

Acquisition of Propylene Fractionation Business. 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 acquisition includes a 66.7% interest in a polymer grade propylene fractionation facility located in Mont Belvieu, Texas, a 50% interest in a polymer grade propylene export terminal located in the Houston Ship Channel and varying interests in several supporting distribution pipelines and related equipment. This Mont Belvieu facility has the capacity to produce approximately 41 MBPD of polymer grade propylene.

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 30 salt dome storage caverns located in Mont Belvieu, Texas with a useable capacity of 68 million barrels, local distribution pipelines and related equipment. The facilities provide storage services for mixed NGL products and olefins, such as ethylene and propylene. The facilities, together with our existing storage facilities, serve the largest concentration of petrochemical and refinery facilities in the United States, and represent the largest NGL and petrochemical underground storage operation in the world.

OUR 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 provide the raw materials for these projects or purchase the projects' end products;

- continue to 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.

COMPETITIVE STRENGTHS

We believe that our integrated network of midstream energy assets is well-positioned to benefit from demand for our services from producers and consumers of natural gas, NGLs and petrochemicals. Our most significant competitive strengths are:

Strategic locations. Our operations are strategically located to serve the major supply basins of NGL-rich natural gas, the major NGL markets and storage hubs in North America and international markets. Our location in these markets ensures continued access to natural gas, NGL and petrochemical supply volumes, anticipated demand growth and business expansion opportunities.

- The acquisition of the Mid-America and Seminole pipeline systems significantly expands our access to NGL supply regions and markets. Our pipeline systems serve the two fastest growing natural gas and NGL production areas in the United States, the deepwater Gulf of Mexico and the Rocky Mountain Overthrust, as well as the San Juan and Permian basins, the Mid-Continent region and, through third-party pipeline connections, north into Canada's Western Sedimentary basin.

- We have significant operations on the Gulf Coast of the United States, which accounts for approximately 55% of domestic NGL production and 79% of domestic NGL demand. Our asset position at Mont Belvieu on the Texas Gulf Coast is the most significant NGL marketplace in the world because of the large salt dome storage capacity at Mont Belvieu, its access to supplies of raw materials and end-product markets through domestic pipeline systems and import/export facilities on the Houston Ship Channel.

- Our system is connected to 97% of the domestic petrochemical steam cracking market, which is the largest consumer of NGL products.

Integrated platform of assets. Our assets are physically linked to create the only integrated natural gas and NGL transportation, fractionation, processing, storage and import/export network in North America, which connects the largest supply basins to the largest consumer markets, both domestic and international.

- Our asset platform allows us to be a single-source provider of a comprehensive package of essential midstream energy services to producers and consumers of natural gas, NGLs and petrochemicals.

- Our asset platform provides customers with valuable alternatives, such as connections to multiple sources of supply and markets.

- Our asset platform has multiple entry points. Hydrocarbons can enter our integrated system through offshore natural gas pipelines, natural gas processing plants, mixed NGL gathering or transportation pipelines, NGL fractionators, NGL storage facilities, NGL product transportation or distribution pipelines or onshore natural gas pipelines. At each link along this value chain, we either earn a fee based on volume or receive mixed NGLs or NGL products.

Relationships with major oil, natural gas and petrochemical companies. We have long-term relationships with many of our suppliers and customers. We jointly own facilities with many of our customers who either provide raw materials to or consume the end products produced from our facilities.

- In connection with our acquisition of Shell Oil Company's midstream energy business in September 1999, we entered into a 20-year agreement with Shell that gives us the option to process all of Shell's current and future natural gas production from the Gulf of Mexico under a life of lease dedication.

- Our partners in our NGL fractionator in Baton Rouge, Louisiana are Exxon Mobil, BP and Williams, who collectively supplied 100% of the NGLs fractionated at this facility in 2001.

- Our partner in our propylene fractionator in Baton Rouge, Louisiana is Exxon Mobil, who provides 100% of the raw material and takes 100% of the fractionated propylene at this facility.

- Our partners in our Promix NGL fractionator in Napoleonville, Louisiana are Dow Chemical and Koch Industries, who collectively purchased 50% of the NGL and petrochemical products produced at this facility during 2001.

- Our partners in our NGL fractionator in Mont Belvieu, Texas are Burlington Resources and Duke Energy, who collectively supplied 49% of the NGLs volumes fractionated at this facility in 2001.

- Our partners in our offshore natural gas gathering pipelines are Shell and Marathon, who have dedicated over 110 blocks, or 1,000 square miles, to the Manta Ray, Nautilus and Nemo pipeline systems.

- Our other major joint venture partners are ChevronTexaco, Sunoco, El Paso and Devon Energy.

- We also have long-term relationships with major consumers of NGL products such as Lyondell and Huntsman.

Large-scale, low-cost integrated operations. We believe the operating costs of our large-scale facilities are either competitive with or significantly lower than those of our competitors.

- Our facilities benefit from economies of scale, which provide cost per unit advantages over competitors with smaller facilities.

- Our largest facilities in Mont Belvieu, Texas and Baton Rouge, Louisiana have been engineered to incorporate efficient gas turbines, a proprietary heat pump design and cogeneration technology to reduce energy costs, which are the largest component of operating costs in fractionating NGLs.

- Our infrastructure provides us with a platform for cost-effective expansion through development projects or acquisitions.

Experienced operator. We have historically operated our largest natural gas processing and fractionation facilities and most of our pipelines.

- As the leading provider of NGL-related services, we have established a reputation in the industry as a reliable and cost-effective operator.

- By virtue of our successful and award-winning operating and safety record, we believe we are well positioned to continue to operate as a large-scale processor of natural gas, NGLs and other products for our customers.

Experienced management team. Our senior management team averages more than 27 years of industry experience. Through our acquisition of Shell's midstream energy business and the Diamond-Koch propylene fractionation business, we have broadened and deepened our senior management team.

PIPELINES

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

NATURAL GAS PIPELINES

We entered the natural gas pipeline business in 2001, when we invested $338 million in this business, including $226 million paid to Shell for the purchase of Acadian Gas (an onshore Louisiana system) and a combined $112 million paid to El Paso for equity interests in four Gulf of Mexico natural gas pipelines (primarily Gulf of Mexico offshore Louisiana systems). We believe that these assets have attractive growth attributes given the expected long-term increase in natural gas demand for industrial and power generation uses. In addition, these assets expanded our midstream energy service relationship with long-term NGL customers (producers, petrochemical suppliers and refineries) and provide us with opportunities to generate additional fee-based cash flows.

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. Our Acadian Gas operation 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. We are exposed to concentrations of customers in certain market segments (such as the chemical and refining industry in south Louisiana) in which the business cycle could affect their creditworthiness and ability to continue business with us. Our Gulf of Mexico offshore pipeline systems compete 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 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 they are connected to, then throughput volumes on these pipelines will decline, thereby affecting our earnings from these investments. We actively seek to offset the loss of volumes due to natural depletion by adding connections to new customers and fields.

In light of the complex, interconnected nature of the pipeline networks and the varying diameter of pipe used and pressure employed, the utilization of these assets is measured in MMBtu/d of natural gas transported.

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 Gas	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	2,041	

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(1) The VESCO gas gathering pipelines are an integral part of the natural gas processing activities of VESCO, the assets of which are accounted for as part of our Processing segment.

Acadian Gas, Cypress and Evangeline. In April 2001, we acquired Acadian Gas from Shell for $244 million. Acadian Gas 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. 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, Cypress and Evangeline systems are comprised of 1,042 miles of pipeline. During 2001, these systems had an average throughput of 783,485 MMBtu/d of natural gas during the period in which we owned or had an interest in these assets, on a net basis.

The Acadian Gas and Evangeline 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 pipelines and a bi-directional interconnect with the U.S. natural gas marketplace at the Henry Hub.

Stingray. In January 2001, we purchased a 50.0% 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, FERC-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. The natural gas dehydration facility is connected to the onshore terminus of the Stingray system in south Louisiana. During 2001, this system transported 300,000 MMBtu/d of natural gas, on a net basis. Shell is the operator of these systems and owns the remaining equity interest in Starfish.

Manta Ray, Nautilus and Nemo. In conjunction with our purchase of the Stingray interest, we also acquired from El Paso a 25.7% 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 FERC-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% 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 for Nautilus. Shell and Marathon are our co-owners in Neptune and Shell owns the remaining interest in Nemo. These systems transported a combined 265,914 MMBtu/d of natural gas during 2001, on a net basis.

NGL AND PETROCHEMICAL PIPELINES

Our NGL and petrochemical pipelines transport mixed NGLs and hydrocarbons to our fractionation plants, distribute NGL products and propylene to petrochemical plants and refineries and deliver propane to customers along the Dixie pipeline. Our pipelines provide transportation services to customers on a fee basis. Therefore, the results of operation for this business are generally dependent upon the volume of product transported and the level of fees charged to customers (which include our merchant businesses). Taken as a whole, this business area does not exhibit a significant degree of seasonality. However, volumes on the Dixie pipeline are higher in the November through March timeframe due to increased use of propane for heating in the southeastern United States. In addition, volumes on the Lou-Tex NGL pipeline are generally higher during the April through September period due to gasoline blending considerations at refineries.

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, utilization is measured in terms of throughput (in MBPD, on a net basis).

	FOR YEAR ENDED DECEMBER 31,		
NGL AND PETROCHEMICAL PIPELINES	1999	2000	2001
Dixie	14	14	26
Louisiana Pipeline System	74	115	138
Lou-Tex Propylene	n/a	23	27
Lou-Tex NGL	n/a	30	29
HSC	99	106	133
Tri-States, Wilprise and Belle Rose	41	42	36
Lake Charles/Bayport	5	5	6
Chunchula	7	6	5
Promix (1)	29	33	28
Total	269	374	428
Pipelines acquired in 2002			
Mid-America Pipeline System (2)	634	637	641
Seminole Pipeline (2)	245	245	241
Total NGL and petrochemical pipelines	1,148	1,256	1,310

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(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) These assets were owned by Williams in 1999, 2000 and 2001, and we have estimated our net utilization based on our current ownership percentages.

In the markets we serve, we compete with a number of intrastate and interstate liquids pipeline companies (including those affiliated with major oil and gas companies) and barge 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 are cost effective and allow for significant flexibility in rendering transportation services for our customers.

The following table summarizes our principal 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%
Lake Charles/Bayport	164	50.0%
Chunchula	117	100.0%
Belle Rose	48	41.7%
Wilprise	30	37.4%
Total NGL and petrochemical pipelines	11,954	

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(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.

Mid-America Pipeline System. The Mid-America pipeline system is a major NGL pipeline system with 7,226 miles of pipe that transports NGLs from the Rocky Mountains, the Midwest and a portion of the Southwest to Mont Belvieu, the largest NGL hub in the United States. Approximately 20 natural gas processing plants in Wyoming, Utah and Colorado feed NGLs into the pipeline system for delivery in the Midwest. The average transportation volumes on the Mid-America pipeline system over the last three years were approximately 640 MBPD. Williams currently operates this pipeline under a transition services agreement.

Dixie. The Dixie pipeline is a 1,301-mile propane pipeline which transports propane supplies from Mont Belvieu, Texas and Louisiana to markets in the southeastern United States. We own a 19.9% interest in Dixie. An affiliate of Phillips operates the system.

Seminole Pipeline System. The Seminole pipeline system is a 1,281-mile pipeline system that transports mixed NGLs and NGL products from Hobbs, Texas and the Permian Basin to Mont Belvieu, Texas. The average volume transported on the Seminole Pipeline System over the last three years was approximately 245 MBPD. Williams currently operates this pipeline under a transition services agreement.

Louisiana Pipeline System. The Louisiana pipeline system is a 536-mile network of nine NGL pipelines located in Louisiana. This system is used to transport NGL products 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 gas processing plants and other facilities located in Louisiana. In general, we own and operate these pipelines.

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. This pipeline is used to deliver 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 participate in three pipeline joint ventures that supply mixed NGLs to the BRF and Promix NGL fractionators. We own a 33.3% interest in Tri-States, which owns a 169-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 near Kenner, Louisiana to Promix. We own a 37.4% interest in Wilprise, which owns a 30-mile NGL pipeline that extends from near Kenner, Louisiana to Sorrento, Louisiana. Williams operates the Tri-States and Wilprise systems.

Lake Charles/Bayport. Our Lake Charles/Bayport system is a 164-mile propylene pipeline used to distribute polymer grade propylene from Mont Belvieu to an affiliate of Shell's polypropylene plants in Lake Charles, Louisiana and Bayport, Texas and to Aristech's facility in La Porte, Texas. A segment of the pipeline is jointly owned by us and a Shell affiliate, and another segment is leased from Exxon Mobil.

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.

Promix NGL Pipeline System. The Promix pipeline system is a 410-mile NGL gathering pipeline that gathers mixed NGLs from 12 processing plants in Louisiana, including the Neptune plant, for delivery to the Promix fractionator.

NGL AND PETROCHEMICAL STORAGE AND IMPORT/EXPORT TERMINAL

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

We also own storage facilities located at Breaux Bridge, Napoleonville, Sorrento and Venice, Louisiana having a gross capacity of 33 MMBbls and a net capacity of 14.8 MMBbls. Our Mississippi storage assets are comprised of facilities located at or near Petal and Hattiesburg having a gross capacity of 12 MMBbls and a net capacity of 9.5 MMBbls. Of the facilities located in Louisiana and Mississippi, we operate those located in Breaux Bridge, Louisiana and Petal, Mississippi. Affiliates of Koch, Dynegy and Shell operate the remaining facilities. In January 2002, we completed the purchase of Diamond-Koch's Mont Belvieu storage assets for $129 million. These facilities include 30 storage wells with a useable capacity of 68 MMBbls and allow for the storage of mixed NGLs, NGL products and petrochemicals. With the addition of these facilities, we own and operate 95 MMBbls of storage capacity at Mont Belvieu. 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 five states. The Mid-America and Seminole storage facilities have a gross capacity of 4.6 MMBbls and a net capacity of 4.5 MMBbls. The following table summarizes our storage assets:

STORAGE ASSETS	GROSS CAPACITY, MMBBLS	NET CAPACITY, MMBBLS
Texas	95.9	95.7
Louisiana	33.0	14.8
Mississippi	12.0	9.5
New Mexico	2.7	2.6
Iowa	0.5	0.5
Nebraska	0.3	0.3
Oklahoma	0.1	0.1
Total	144.5	123.5

When used in conjunction with our processing operations, these wells allow us to mix various batches of feedstock and maintain 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. Our intersegment revenues for the Pipelines segment include those fees charged to our various merchant businesses for use of the storage facilities.

We are also in the merchant storage business, with our focus being to attract customers to store products in our wells for a fee. Our competitors in this area are other merchant storage and pipeline companies such as TEPPCO, Dynegy and Equistar. Major oil and gas companies such as Exxon Mobil and ConocoPhillips occasionally use their proprietary storage assets in a merchant role thereby entering into competition with us and other merchant providers. Our Mont Belvieu facilities (including those recently acquired from Diamond-Koch) represent the largest merchant storage facilities in the world for NGLs and olefins. We compete with other service providers primarily in terms of the fees charged, pipeline connections and dependability. We believe that due to the integrated nature of our operations, our storage customers have access to a competitively priced, flexible and dependable network of assets.

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 laytime 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. Typically, our import activity exhibits little seasonality; however, throughput can be positively affected when domestic demand for NGL products exceeds supply making it profitable to transport mixed NGLs and NGL products by barge or ship from overseas locations or other domestic ports. For example, imports of normal butane destined for our isomerization plants increased significantly during the second quarter of 2001 due to demand for isobutane. In addition, we own a 50.0% interest in EPIK, which owns NGL export facilities at the same terminal including an NGL products chiller and related equipment used for loading refrigerated marine tankers. The export terminal can load vessels of refrigerated propane and butane at rates up to 5,000 barrels per hour. Traditionally, EPIK's export volumes are higher during the winter months due to increased propane exports. The profitability of import and export activities primarily depends upon the quantities loaded and offloaded and the throughput fees associated with each activity.

The following table shows volumes loaded and offloaded through our import/export terminal over the last three years (in MBPD, on a net basis):

FACILITY	FOR YEAR ENDED DECEMBER 31, 1999	2000	2001
NGL import facility	14	9	45
EPIK	10	17	8
Total Imports and Exports	24	26	53

When compared to 2000, export activity declined as strong domestic pricing for products reduced the economic need to export. Normal butane imports were higher in 2001 due to increased isobutane production.

Our NGL import and EPIK's NGL export facility have a small number of competitors, primarily Dynegy and Dow. These operations compete 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.

In February 2002, we acquired a 50.0% interest in OTC, which owns a dock facility located in Seabrook, Texas for the receipt, storage, handling and redelivery of polymer grade propylene. We acquired our interest in OTC in connection with our purchase of the Mont Belvieu III propylene fractionation facility from Diamond-Koch. At maximum rates, this facility can load 144 MBPD of polymer grade propylene onto ships and barges. The OTC facility is an integral part of our Mont Belvieu III propylene fractionation business, of which the assets and earnings (including those of OTC) are accounted for as 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, 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 refined 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 impurities and 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 most important source of throughput for 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, leading to a reduction in volumes available for NGL fractionation.

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.

The majority of our NGL fractionation facilities process mixed NGL streams for third-party customers and our NGL merchant business by charging them a toll fractionation fee. Toll fee arrangements typically include a base cents per gallon fee for mixed NGLs processed subject to adjustment for changes in certain fractionation expenses. At our Norco facility, we are paid for fractionation services by receiving a percentage of NGLs fractionated for third-party customers, or in-kind fees. The results of operation 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 only). The NGL fractionation business exhibits little to no seasonal variation. Lastly, we are exposed to the pricing risks of NGLs only to the extent that we receive in-kind fees for our services, since our customers generally retain title to the mixed NGL streams that we process and the NGL products that are ultimately produced.

Our management believes 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, significant volumes of mixed NGLs are contractually committed to our facilities by joint owners and third-party customers.

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 475 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 two 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 303 MBPD. The following table summarizes our NGL fractionation facilities:

NGL FRACTIONATION FACILITY	LOCATION	GROSS CAPACITY, MBPD	OUR OWNERSHIP INTEREST	OUR NET CAPACITY, MBPD
Mont Belvieu	Texas	210	62.5%	131
Norco	Louisiana	70	100.0%	70
Promix	Louisiana	145	33.3%	48
BRF	Louisiana	60	32.2%	19
Toca-Western	Louisiana	14	100%	14
Tebone	Louisiana	30	28.9%	9
Petal	Mississippi	7	100.0%	7
Venice	Louisiana	36	13.1%	5
Total		572		303

During 2001, our NGL fractionation facilities processed mixed NGLs at an average rate of 204 MBPD or 70% 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, 1999	2000	2001
Mont Belvieu	78	106	110
Norco	48	47	41
BRF	13	15	14
Promix	30	34	30
Other	15	11	9
Total net volume	184	213	204
Net capacity	264	290	290
Utilization rate	70%	73%	70%

Mont Belvieu. We operate one of the largest NGL fractionation facilities in the United States with a gross processing capacity of 210 MBPD at Mont Belvieu, Texas. Mont Belvieu is the hub of the domestic NGL industry because of its proximity to the largest concentration of refineries and petrochemical plants in the United States and its location on a large naturally-occurring salt dome that provides for the underground storage of significant quantities of NGLs. Our Mont Belvieu NGL fractionation facility is supported by long-term fractionation agreements with Burlington Resources and Duke (accounting for 63 MBPD of net processing volume in 2001), each of which is a significant producer of NGLs and a co-owner of the facility. We own an effective 75% interest in this facility.

Norco. We own and operate an NGL fractionation facility at Norco, Louisiana. The Norco facility receives mixed NGLs via pipeline from the Yscloskey, Toca and Crawfish gas processing plants in Louisiana and has a gross processing capacity of 70 MBPD. During 2001, long-term in-kind fee arrangements exclusive to this facility accounted for approximately 41 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.

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 315-mile mixed NGL gathering system connected to nine gas processing plants, five NGL salt dome storage wells and a barge loading facility. Promix receives mixed NGLs from numerous gas processing plants located in southern Louisiana.

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 28.9% interest in a 30 MBPD NGL fractionation facility located in Asceasion Parish, Louisiana. The Tebone NGL fractionation facility was built in the 1960s and receives NGLs from the North Terreborne 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, for our toll processing customers, including our isobutane merchant business that is part of our Processing segment. 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. We, as well as our partners in BEF, use the high purity isobutane produced by these facilities to meet our feedstock obligations of the MTBE plant under tolling arrangements. Our isobutane merchant business uses the isomerization facilities to meet the requirements of its isobutane sales contracts when the processing of company-owned inventories of normal and/or mixed butanes is necessary. During 2001, 18 MBPD of isobutane production was attributable to our merchant activities, 14 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:

ISOMERIZATION FACILITIES	FOR YEAR ENDED DECEMBER 31, 1999	2000	2001
Production	74	74	80
Capacity	116	116	116
Utilization rate	64%	64%	69%

In the isomerization market, we compete 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 the 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. Overall, the propylene fractionation business exhibits little seasonality.

Results of operations for our polymer grade propylene plants are generally dependent upon toll processing arrangements and propylene merchant activities. Under toll processing arrangements, we are paid fees based on throughput of refinery grade propylene used to produce polymer grade propylene. Our largest toll processing customers in 2001 were Huntsman and Equistar. In our propylene merchant business, we have several long-term polymer grade propylene sales agreements, the largest of which is with an affiliate of Shell. To meet our merchant obligations, we have entered into several long-term agreements to purchase refinery grade propylene. To limit the exposure to price risk in the merchant side of this business, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products. During 2001, 10 MBPD of our net polymer grade propylene production was associated with toll processing operations with the balance attributable to merchant activities.

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. In turn, polymer grade propylene is transported to customers by truck or pipeline. We also can load and unload volumes of polymer grade propylene as a result of our 50% investment in Olefins Terminal Corporation located in Seabrook, Texas.

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 cost efficient which allows us to be very 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 propylene fractionation business consists of three polymer grade propylene facilities and one chemical grade propylene plant. These assets include a controlling interest in our Mont Belvieu III unit, which we purchased from Diamond-Koch in February 2002. The following table summarizes our propylene fractionation business assets and ownership:

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

During 2001, our propylene fractionation facilities produced at an average rate of 31 MBPD or 82% of capacity, both amounts on a net basis. The table below shows our net production volumes and capacity (both in MBPD) based on our current ownership interest and the corresponding overall utilization rates of our facilities for the last three years:

	FOR YEAR ENDED DECEMBER 31,		
PROPYLENE FRACTIONATION FACILITY	1999	2000	2001
Mont Belvieu I and II (1)	28	29	27
BRPC	n/a	4	4
Total net volume	28	33	31
Net capacity	31	35	38
Utilization rate	90%	94%	82%

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(1) Does not include information for Mont Belvieu III, which we did not own during the periods indicated.

Mont Belvieu I, II and III. We operate three polymer grade propylene fractionation facilities (Mont Belvieu I, II and III) in Mont Belvieu, Texas having a combined capacity of 58.3 MBPD. We own a 54.6% interest in Mont Belvieu I, all of Mont Belvieu II and a 66.7% interest in Mont Belvieu III. We lease the remaining 45.4% interest in Mont Belvieu I from an affiliate of Shell.

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 merchant 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 (3.38 Bcf/d on a net basis). Our net share of the NGL production from these plants, in addition to NGLs we purchase on a merchant basis and a portion of the production from our Mont Belvieu isomerization facilities, support the merchant activities included in this operating segment.

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 are defined as "keepwhole contracts." The processor 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, multiplied by the market value of natural gas. The processor derives a profit margin to the extent the market value of the NGLs extracted exceeds the costs of extraction.

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 the largest oil and gas producer 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 to process substantially all of Shell's Gulf of Mexico natural gas production; plus

- the exclusive right to process all natural gas production from leases dedicated by Shell; 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.

Several deepwater Gulf of Mexico developments began production during 2001. These include Shell's Ursa, Brutus, Oregano, Crosby, Einset and Serrano developments. As a result of these new streams of rich natural gas, in the fourth quarter of 2001, we had record equity NGL production of 80 MBPD.

Our natural gas processing facilities are primarily straddle plants that are situated on mainline natural gas pipelines that bring unprocessed Gulf of Mexico natural gas production onshore. Straddle plants 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 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 by our merchant business to meet contractual requirements or sold on spot and forward markets.

The natural gas throughput 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 63 MBPD during 2001, 72 MBPD during 2000 and 67 MBPD during 1999.

As noted previously, we take title to a portion of the mixed NGLs that are extracted by the gas 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 overall merchant business activities. In our isomerization merchant activities, we are party to a number of isobutane sales contracts. To fulfill our obligations under these sales contracts, we can purchase isobutane on the spot market for resale, sell our isobutane in 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.

Since 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. 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. We attempt to mitigate these risks through the use of commodity financial instruments.

The following table lists our gas processing plants, processing capacities and corresponding ownership interest:

NATURAL GAS PROCESSING FACILITY	LOCATION	GROSS GAS PROCESSING CAPACITY (BCF/D)	OUR OWNERSHIP INTEREST	NET GAS PROCESSING CAPACITY (BCF/D)
Yscloskey	Louisiana	1.85	28.2%	0.52
Calumet	Louisiana	1.60	35.4%	0.57
North Terrebonne	Louisiana	1.30	28.9%	0.38
Venice	Louisiana	1.30	13.1%	0.17
Toca	Louisiana	1.10	60.2%	0.66
Pascagoula	Mississippi	1.00	40.0%	0.40
Sea Robin	Louisiana	0.95	15.5%	0.15
Blue Water	Louisiana	0.95	7.4%	0.07
Patterson II	Louisiana	0.60	2.0%	0.01
Iowa	Louisiana	0.50	2.0%	0.01
Neptune	Louisiana	0.30	66.0%	0.20
Toca-Western	Louisiana	0.16	100%	0.16
Burns Point	Louisiana	0.16	50.0%	0.08
Total		11.77		3.38

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).

Our gas processing business and related merchant 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 merchant activities as we do. Our competitive 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 merchant activities utilize a fleet of approximately 625 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 our and our customers' rail shipments. This segment also 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 Louisiana.

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 capacity of the MTBE facility is approximately 15 MBPD with a net capacity of 5 MBPD. For the years 2001, 2000 and 1999, net production averaged 5 MBPD. 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. Additionally, motor gasoline containing MTBE can be transported through pipelines, which is a significant competitive advantage over alcohol blends such as ethanol.

MTBE demand is 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 Developments" below).

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 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. 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 world-class scale 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 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. For example, the Governor of California ordered the phase-out of MTBE in California on March 25, 1999. 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. In addition, Congress is contemplating a federal ban on MTBE. On April 25, 2002, the Senate approved an energy bill that in part would ban the use of MTBE within four years of enactment and require the use of ethanol as a substitute for MTBE. 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" in our Annual Report on Form 10-K for the year ended December 31, 2001.

Alternative uses of the BEF facility. In light of these regulatory developments, the owners of BEF have been formulating a contingency plan for use of the BEF facility if MTBE were banned or significantly curtailed. Our management is exploring possible conversion of the BEF facility from MTBE production to alkylate production. 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 motor gasoline and that alkylate would be an attractive substitute. We are currently undergoing an engineering study that is expected to be completed by the end of the first quarter of 2003, at which time a 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.

OTHER

This operating segment is primarily comprised of fee-based marketing services. 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. We utilize the resources of our merchant businesses to perform these services. 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 23 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. This segment also includes other engineering services, construction equipment rentals and computer network services that support other operations and business activities.

EMPLOYEES

We do not have any employees. EPCO employs all the persons necessary for the operation of our business. At June 30, 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 reimburse EPCO for the services of certain of its employees under a long-term services agreement.

MAJOR CUSTOMERS

Our revenues are derived from a wide customer base. Our largest customer, Shell, accounted for 9.5% and 10.5% of consolidated revenues in 2000 and 2001, respectively. Approximately 80% of our revenues from Shell during these periods were attributable to sales of NGL products, which are recorded in our Processing segment.

REGULATION AND ENVIRONMENTAL MATTERS

Our operations are subject to extensive regulations. Many federal, state and local departments and agencies are authorized by statute to issue and have issued laws and regulations binding on the energy industry and its individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the energy industry increases our cost of doing business and, consequently, affects our profitability. However, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors. For a more detailed description of regulatory issues affecting our business, please refer to Items 1 and 2 "Business and Properties -- Regulation and Environmental Matters" in our Annual Report on Form 10-K for the year ended December 31, 2001.

MANAGEMENT

The following table sets forth certain information with respect to the executive officers and members of the board of directors of our general partner. Executive officers and directors are elected for one-year terms.

NAME	AGE	POSITION WITH GENERAL PARTNER
Dan L. Duncan	69	Director and Chairman of the Board
O. S. Andras	67	Director, President and Chief Executive Officer
Richard H. Bachmann	49	Director, Executive Vice President, Chief Legal Officer and Secretary
Michael A. Creel	48	Executive Vice President and Chief Financial Officer
A.J. Teague	57	Executive Vice President
William D. Ray	67	Executive Vice President
Charles E. Crain	70	Senior Vice President
A. Monty Wells	56	Senior Vice President
W. Ordemann	43	Senior Vice President
Gil H. Radtke	41	Senior Vice President
Michael J. Knesek	48	Vice President, Controller and Principal Accounting Officer
W. Randall Fowler	46	Vice President and Treasurer
Randa D. Williams	41	Director
J.R. Eagan	48	Director
J.A. Berget	49	Director
Dr. Ralph S. Cunningham	61	Director
Augustus Y. Noojin, III	55	Director
Lee W. Marshall, Sr.	70	Director
Richard S. Snell	60	Director

Dan L. Duncan was elected Chairman of the Board 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.

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.

Richard H. Bachmann was elected a Director of our general partner in June 2000. He has served as Executive Vice President and Chief Legal Officer of our general partner and EPCO since January 1999. Previously, he was a partner with the legal firms of Snell & Smith P.C. and Butler & Binion.

Michael A. Creel was elected an Executive Vice President of our general partner in February 2001, having served as a Senior Vice President of our general partner since November 1999. In June 2000, Mr. Creel, a certified public accountant, assumed the role of Chief Financial Officer of our company along with his other responsibilities. From 1997 to 1999 he held a series of positions with a Shell affiliate, including Senior Vice President, Chief Financial Officer and Treasurer. From 1995 to 1997, Mr. Creel was Vice President and Treasurer of NorAm Energy Corp.

A.J. ("Jim") Teague was elected an Executive Vice President of our general partner in November 1999. From 1998 to 1999 he served as President of 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 has served as EPCO's Executive Vice President of Supply and Marketing since 1985.

Charles E. Crain was elected a Senior Vice President of our general partner in April 1998. Mr. Crain has served as Senior Vice President of Operations for EPCO since 1991.

A. Monty Wells was elected a Senior Vice President of our general partner in June 2000. Mr. Wells has served in a number of managerial positions with EPCO since 1980 including Vice President of Marketing and Supply.

W. ("Bill") Ordemann was elected a Senior Vice President of our general partner in September 2001. Mr. Ordemann has served in executive level positions in our NGL businesses since 1999. From 1996 to 1999, he served as a Vice President of two Shell affiliates, including TNGL.

Gil H. Radtke was elected a Senior Vice President of our general partner in February 2002. Mr. Radtke joined our company in connection with our purchase of affiliates of Diamond-Koch's storage and propylene fractionation assets in January and February 2002. Before joining our company, Mr. Radtke served as President of the affiliates of Diamond-Koch joint venture where he was responsible for its storage, propylene fractionation, pipeline and NGL fractionation businesses. Mr. Radtke was employed by Valero Energy Corporation (a partner in the affiliates of Diamond-Koch joint venture) for the last eighteen years in various commercial and analysis roles.

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.

W. Randall Fowler was elected Treasurer and a Vice President of our general partner in August 2000. Mr. Fowler joined our company as director of investor relations in 1999. From 1995 to 1999, Mr. Fowler served in a number of corporate finance and accounting-related capacities at NorAm Energy Corp., including Director of Finance Wholesale Energy Marketing and Assistant Treasurer.

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. (Jeri) Eagan was elected a Director of our general partner in October 2000. Since 1999, Ms. Eagan has served in various executive-level positions with Shell and currently holds the office of Chief Financial Officer of Shell Oil Company in addition to that of Vice President Finance & Commercial Operations of a Shell subsidiary. From 1994 to 1999, she worked on several assignments for the Royal Dutch/Shell Group of companies in London.

J.A. (Jorn) Berget was elected a Director of our general partner in November 2000. Since 1995, Mr. Berget has served in various managerial positions for the Royal Dutch/Shell Group of companies and Shell, including Vice President and General Manager for one of its subsidiaries since 2000. 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 former director of EPCO from 1987 to 1997. Dr. Cunningham serves as Chairman of our Audit and Conflicts Committee.

Augustus Y. ("Gus") Noojin, III was elected a Director of our general partner in May 2002. Mr. Noojin was elected President and Chief Executive Officer of Shell U.S. Gas & Power LLC, an affiliate of Shell, in May 2002, and has held various other executive-level positions with affiliates of Shell.

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 since 1993. He has also served in senior management positions with Union Pacific Resource and Tenneco Oil. 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. for seven years after founding the firm in 1993. He is currently a partner with the law firm of Thompson & Knight LLP in Houston, Texas and is a certified public accountant. Mr. Snell is a member of our Audit and Conflicts Committee.

TAX CONSIDERATIONS

The tax consequences to you of an investment in common units will depend in part on your own tax circumstances. For a discussion of the principal federal income tax considerations associated with our operations and the ownership and disposition of common units, please read "Tax Considerations" in the accompanying prospectus. You are urged to consult your own tax advisor about the federal, state, local and foreign tax consequences peculiar to your circumstances.

We estimate that if you purchase common units in this offering and own them through December 31, 2005, then you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be less than 10% of the cash distributed with respect to that period. If you own common units purchased in this offering for a shorter period, the percentage of federal taxable income allocated to you may be higher. These estimates are based upon the assumption that our available cash for distribution will approximate the amount required to distribute cash to the holders of the common units in an amount equal to the announced quarterly distribution of $0.345 per unit and other assumptions with respect to capital expenditures, cash flow and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and certain tax reporting positions that we have adopted with which the IRS could disagree. In addition, subsequent issuances of equity securities by us could also affect the percentage of distributions that will constitute taxable income. Accordingly, we cannot assure you that the estimates will be correct. The actual percentage of distributions that will constitute taxable income could be higher or lower, and any differences could be material and could materially affect the value of the common units.

UNDERWRITING

Under the underwriting agreement, which is filed as an exhibit to the registration statement of which this prospectus supplement and the accompanying prospectus form a part, each of the underwriters named below has severally agreed to purchase from us the respective number of common units opposite its name below:

UNDERWRITERS	NUMBER OF COMMON UNITS
Lehman Brothers Inc.	
Goldman, Sachs & Co.	
UBS Warburg LLC	
RBC Dain Rauscher Inc.	
Wachovia Securities, Inc.	
McDonald Investments Inc.	
Raymond James & Associates Inc.	
Sanders Morris Harris	
Total	9,300,000

Dan L. Duncan, the Chairman of our general partner, through EPC Partners II, Inc., an entity controlled by him, and O.S. Andras, the President and Chief Executive Officer of our general partner, expect to purchase up to 1,800,000 common units in this offering directly from the underwriters at a price equal to the public offering price.

At the request of Enterprise Products Partners, the underwriters have reserved up to 10,000 common units for sale under a directed unit program to senior management. The number of common units available for sale to the general public will be reduced to the extent these individuals purchase reserved common units. These shares will be sold at the public offering price, but the underwriters will receive no underwriting discount or commission on the sale of common units under the directed unit program.

The underwriting agreement provides that the underwriters are obligated to purchase, subject to certain conditions, all of the common units in the offering if any are purchased, other than those covered by the over-allotment option described below. The conditions contained in the underwriting agreement include the requirements that:

- all the representations and warranties made by us to the underwriters are true;

- there has been no material adverse change in our condition or in the financial markets; and

- we deliver to the underwriters customary closing documents.

We have granted to the underwriters a 30-day option after the date of the underwriting agreement to purchase, in whole or in part, up to an aggregate of 1,125,000 additional common units at the public offering price less underwriting discounts and commissions. Such option may be exercised to cover over-allotments, if any, made in connection with the offering. To the extent that the option is exercised, each underwriter will be obligated, subject to certain conditions, to purchase its pro rata portion of these additional common units based on the underwriter's percentage underwriting commitment in the offering as indicated on the preceding table.

We have been advised by the underwriters that the underwriters propose to offer the common units directly to the public at the price to the public set forth on the cover page of this prospectus supplement and to selected dealers (who may include the underwriters) at the offering price less a selling concession not in excess of $ per unit. The underwriters may allow, and the selected dealers may reallow, a discount from the concession not in excess of $ per unit to other dealers. After the offering, the underwriters may change the offering price and other selling terms.

The following table shows the underwriting discounts and commissions we will pay to the underwriters. These amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase additional common units. The underwriting fee is the difference between the initial offering price and the amount the underwriters pay to us to purchase the common units from us.

	NO EXERCISE	FULL EXERCISE
Per unit	$	$
Total	$	$

We estimate that the total expenses of the offering, excluding underwriting discounts and commissions, will be approximately $1.0 million.

In connection with this offering, the underwriters may engage in stabilizing transactions, over-allotment transactions, syndicate covering transactions and penalty bids for the purpose of pegging, fixing or maintaining the price of the common units in accordance with Regulation M under the Exchange Act.

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.

- Over-allotment transactions involve sales by the underwriters of the common units in excess of the number of common units the underwriters are obligated to purchase, which creates a syndicate short position. The short position may be either a covered short position or a naked short position. In a covered short position, the number of common units over-allotted by the underwriters is not greater than the number of common units they may purchase in the over-allotment option. In a naked short position, the number of common units involved is greater than the number of common units in the over-allotment option. The underwriters may close out any short position by either exercising their over-allotment option and/or purchasing common units in the open market.

- Syndicate covering transactions involve purchases of the common units in the open market after the distribution has been completed in order to cover syndicate short positions. In determining the source of the common units to close out the short position, the underwriters will consider, among other things, the price of common units available for purchase in the open market as compared to the price at which they may purchase common units through the over-allotment option. If the underwriters sell more common units than could be covered by the over-allotment option, a naked short position, the position can only be closed out by buying common units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the common units in the open market after pricing that could adversely affect investors who purchase in the offering.

- Penalty bids permit the underwriters to reclaim a selling concession from a syndicate member when the common units originally sold by the syndicate member are purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common units or preventing or retarding a decline in the market price of the common units. As a result, the price of the common units may be higher than the price that might otherwise exist in the open market. These transactions may be effected on the NYSE or otherwise and, if commenced, may be discontinued at any time.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common units. In addition, neither we nor any of the underwriters make any representation that the underwriters will engage in these stabilizing transactions or that any transaction, once commenced, will not be discontinued without notice.

We, our affiliates that own common units and the directors and executive officers of our general partner have agreed that we and they will not, subject to limited exceptions, directly or indirectly, sell, offer, pledge or otherwise dispose of any common units or any securities convertible into or exchangeable or exercisable for common units or enter into any derivative transaction with similar effect as a sale of common units for a period of 90 days after the date of this prospectus supplement without the prior written consent of Lehman Brothers Inc. The restrictions described in this paragraph do not apply to the sale of common units to the underwriters.

Lehman Brothers Inc., in its discretion, may release the common units subject to lock-up agreements in whole or in part at any time with or without notice. When determining whether or not to release common units from lock-up agreements, Lehman Brothers Inc. will consider, among other factors, the unitholders' reasons for requesting the release, the number of common units for which the release is being requested and market conditions at the time.

The common units are listed on the NYSE under the symbol "EPD."

We, our general partner and our operating partnership have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act of 1933, or to contribute to payments that may be required to be made in respect of these liabilities.

Some of the underwriters have performed investment banking, commercial banking and advisory services for us from time to time for which they have received customary fees and expenses. The underwriters may, from time to time in the future, engage in transactions with and perform services for us in the ordinary course of business.

Affiliates of Lehman Brothers Inc., RBC Dain Rauscher Inc. and Wachovia Securities, Inc. are lenders to us under our $1.2 billion senior unsecured 364-day term loan. Each of these lenders will receive an equal share of the partial repayment by us of amounts outstanding under this short-term loan from the net proceeds of this offering.

Because the NASD views the common units offered hereby as interests in a direct participation program, the offering is being made in compliance with Rule 2810 of the NASD Conduct Rules. Investor suitability with respect to the common units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

No sales to accounts over which the underwriters have discretionary authority may be made without the prior written approval of the customer.

A prospectus in electronic format may be made available on the Internet sites or through other online services maintained by one or more of the underwriters and/or selling group members participating in this offering, or by their affiliates, in those cases, prospective investors may view offering terms online and, depending upon the particular underwriter or selling group member prospective investors may be allowed to place orders online. The underwriters may agree with us to allocate a specific number of shares for sale to online brokerage account holders. Any such allocation for online distributions will be made by the representatives on the same basis as other allocations.

Other than the prospectus in electronic format, the information on any underwriter's or selling group member's web site and any information contained in any other web site maintained by an underwriter or selling group member is not part of the prospectus or the registration statement of which this prospectus supplement forms a part, has not been approved and/or endorsed by us or any underwriter or selling group member in its capacity as underwriter or selling group member and should not be relied upon by investors.

INCORPORATION OF CERTAIN DOCUMENTS BY REFERENCE

The Commission allows us to "incorporate by reference" into this prospectus supplement and the accompanying prospectus the information we file with it, which means that we can disclose important information to you by referring you to those documents. The information incorporated by reference is considered to be part of this prospectus supplement and the accompanying prospectus, and later information that we file with the Commission will automatically update and supersede this information. We incorporate by reference the documents listed below filed by us and any future filings made by us with the Commission under section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 until our offering is completed:

- Our Annual Report on Form 10-K for the fiscal year ended December 31, 2001;

- Our Quarterly Reports on Form 10-Q for the fiscal quarters ended March 31, 2002 and June 30, 2002;

- Our Current Report on Form 8-K filed with the Commission on August 12, 2002, as amended by our Current Report on Form 8-K/A (Amendment No. 1) filed with the Commission on September 26, 2002 (excluding Item 9 information);

- Our Current Report on Form 8-K filed with the Commission on September 27, 2002; and

- The descriptions of our common units contained in the Registration Statement on Form 8-A, initially filed with the Commission on July 21, 1998, and any subsequent amendment thereto filed for the purposes of updating such description.

LEGAL MATTERS

Certain legal matters with respect to the common units will be passed upon for us by Vinson & Elkins L.L.P., Houston, Texas. Certain legal matters with respect to the common units are being passed upon for the underwriters by Baker Botts L.L.P., Houston, Texas. Baker Botts L.L.P. performs legal services for us and our affiliates from time to time.

EXPERTS

The consolidated financial statements and the related consolidated financial statement schedule of Enterprise Products Partners L.P. and subsidiaries as of December 31, 2001 and 2000 and for each of the three years in the period ended December 31, 2001 included and incorporated by reference in this prospectus supplement have been audited by Deloitte & Touche LLP, independent auditors, as stated in their reports, which are included and incorporated by reference herein (which reports express an unqualified opinion and include an explanatory paragraph referring to a change in method of accounting for derivative instruments in 2001 as discussed in Note 13 to the consolidated financial statements), and have been so included and incorporated in reliance upon the reports of such firm given upon their authority as experts in accounting and auditing.

The financial statements of Mid-America Pipeline System and Seminole Pipeline Company as of December 31, 2000 and 2001 and for each of the three years in the period ended December 31, 2001 appearing in Enterprise Products Partners L.P. and Enterprise Products Operating L.P.'s Current Report on Form 8-K/A (Amendment No. 1) filed September 26, 2002, have been audited by Ernst & Young LLP, independent auditors, as set forth in their reports thereon included therein and incorporated by reference in the Registration Statement and related Prospectus and also included elsewhere in this Prospectus Supplement. These financial statements have been included in this Prospectus Supplement and incorporated by reference in the Registration Statement and related Prospectus in reliance upon such reports given on the authority of such firm as experts in accounting and auditing.

GLOSSARY

The following abbreviations, acronyms or terms used in this prospectus supplement are defined below:

Acadian Gas	Acadian Gas, LLC and subsidiaries, acquired from Shell in April 2001
BBtu	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
Btu	British thermal units, a measure of heating value
Burlington Resources	Burlington Resources Inc. and its affiliates
ChevronTexaco	ChevronTexaco and its affiliates
CPG	Cents per gallon
ConocoPhillips	ConocoPhillips Petroleum Company and affiliates
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
Dow	Dow Chemical Company and its affiliates
Duke	Duke Energy Corporation and its affiliates
Dynegy	Dynegy Inc. and its affiliates
El Paso	El Paso Corporation, its subsidiaries and affiliates
Energy Policy Act	Energy Policy Act of 1992
E-Oaktree	E-Oaktree, LLC
EPCO	Enterprise Products Company, an affiliate of our partnership
EPIK	EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively, an equity investment of EPOLP
EPOLP	Enterprise Products Operating L.P., our operating partnership
Equistar	A joint venture of Lyondell Chemical Company, Millennium Chemicals, Inc. and Occidental Petroleum Corporation
Exxon Mobil	Exxon Mobil Corporation and its affiliates
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	United States Generally Accepted Accounting Principles
HSC	Denotes our Houston Ship Channel pipeline system
Huntsman	Huntsman Corporation and its affiliates
Koch	Koch Industries and its affiliates
LIBOR	London interbank offered rate
Lyondell	Lyondell Chemical Company and its affiliates
Manta Ray	A Gulf of Mexico Offshore Louisiana natural gas pipeline system owned by Manta Ray offshore Gathering Company, LLC
Mapletree	Mapletree, LLC
Marathon	Marathon Oil Corporation and its affiliates
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
MLP	Denotes our partnership
MBbls	Thousands of barrels
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
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
Mont Belvieu	Mont Belvieu, Texas
Mont Belvieu I	Our 54.6% interest in a polymer-grade propylene fractionation facility located in Mont Belvieu, the remaining 45.4% interest in which we lease from an affiliate of Shell
Mont Belvieu II	Our 100% interest in a polymer-grade propylene fractionation facility located in Mont Belvieu
Mont Belvieu III	66.7% interest in a polymergrade propylene fractionation facility located in Mont Belvieu
MTBE	Methyl tertiary butyl ether
Nautilus	A Gulf of Mexico offshore Louisiana natural gas pipeline system owned by Nautilus Pipeline Company, LLC
Nemo	Nemo Gathering Company, LLC, an equity investment of EPOLP
Neptune	Neptune Pipeline Company LLC
NGL or NGLs	Natural gas liquid(s)
Norco	An NGL fractionation facility located at Norco, Louisiana
NYSE	New York Stock Exchange
Operating Partnership	EPOLP and its subsidiaries
OTC	Olefins Terminal Corporation
Promix	K/D/S/ Promix LLC, an equity investment of EPOLP
SEC	U.S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards issued by the FASB
Senior Notes A	Our 8.25% fixed-rate Senior Notes due March 15, 2005
Senior Notes B	Our 7.50% fixed-rate Senior Notes due February 1, 2011
Shell	Shell Oil Company, its subsidiaries and affiliates
Starfish	Starfish Pipeline Company, LLC, an equity investment of EPOLP
Sunoco	Sunoco Inc. and its affiliates
TCEQ	Texas Commission on Environmental Quality
TEPPCO	Texas Eastern Pipeline Partners Company
TNGL acquisition	Refers to the 1999 acquisition of Tejas Natural Gas Liquids, LLC, formerly an affiliate of Shell
Tri-States	Tri-States NGL Pipeline LLC, an equity investment of EPOLP
Trust	EPOLP 1999 Revocable Grantor Trust, a subsidiary of EPOLP
Trust Units	Common units owned by the Trust
VESCO	Venice Energy Services Company, LLC, a cost method investment of EPOLP
Williams	The Williams Companies, Inc.
Wilprise	Wilprise Pipeline Company, LLC, an equity investment of EPOLP

INDEX TO FINANCIAL STATEMENTS

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

INTRODUCTION

On July 31, 2002, we acquired 98% of the ownership interests in two affiliates of The Williams Companies Inc. ("Williams"): Mapletree, LLC and E-Oaktree, LLC. Mapletree, LLC owns 100% of Mid-America Pipeline Company, LLC ("Mid-America") and certain propane terminals and storage facilities. E-Oaktree, LLC owns 80% of Seminole Pipeline Company ("Seminole"). The pro forma financial statements are primarily based upon the combined historical financial position and results of operations of Enterprise Products Partners L.P., Mid-America and Seminole. 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 unaudited pro forma Statements of Consolidated Operations have been prepared as if the acquisitions had occurred on January 1 of the respective periods presented, and the pro forma consolidated balance sheet has been prepared as if the acquisitions occurred on June 30, 2002. The combined purchase price of these acquisitions was approximately $1.2 billion and was primarily funded by an unsecured 364-day term loan of the same amount (the "Term Loan").

The unaudited pro forma financial statements should be read in conjunction with and are qualified in their entirety by reference to the notes accompanying such pro forma consolidated financial statements and with the historical financial statements and related notes of our Company, Mid-America, and Seminole included elsewhere or incorporated by reference in this prospectus.

The unaudited pro forma information is not necessarily indicative of the financial results that would have occurred if the acquisitions described herein had taken place on the dates indicated or we had issued equity and borrowed funds on the dates indicated, nor is it indicative of our future consolidated financial results.

ENTERPRISE PRODUCTS PARTNERS L.P.

PRO FORMA STATEMENT OF CONSOLIDATED OPERATIONS
FOR THE SIX MONTHS ENDED JUNE 30, 2002
(DOLLARS IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)
(UNAUDITED)

ENTERPRISE MID-AMERICA SEMINOLE
ENTERPRISE HISTORICAL HISTORICAL
HISTORICAL OTHER ADJUSTMENTS PRO FORMA
---------- ----------- ---------- -----
-- ----------- ---------- REVENUES
Revenues from consolidated
operations..... $1,448,311 $109,865 $
34,856 $17,434 $ (2,252)(f) $1,608,214
Equity income in unconsolidated
affiliates.............................
16,295 -- -- -- 16,295 ---------- -----
--- -------- ------- -------- ---------
- Total............................
1,464,606 109,865 34,856 17,434 (2,252)
1,624,509 ---------- -------- --------
------- -------- ---------- COST AND
EXPENSES Operating costs and
expenses............. 1,410,044 45,111
17,315 16,231 1,325(b) 1,487,900 126(c)
(2,252)(f) Selling, general and
administrative....... 15,702 15,130 796
260 31,888 ---------- -------- --------
------- -------- ----------
Total............................
1,425,746 60,241 18,111 16,491 (801)
1,519,788 ---------- -------- --------
------- -------- ---------- OPERATING
INCOME......................... 38,860
49,624 16,745 943 (1,451) 104,721 OTHER
INCOME (EXPENSE) Interest
expense.........................
(37,545) (4,432) (2,006) -- 4,148(b)
(67,195) (26,709)(a) (651)(c) Interest
income from unconsolidated
affiliates.............................
92 -- -- -- 92 Dividend income from
unconsolidated
affiliates.............................
2,196 -- -- -- 2,196 Interest income --
other................. 1,575 -- -- --
1,575 Other,
net...............................
(31) (748) (7) -- (786) ---------- ----
---- -------- ------- -------- --------
-- Other income (expense)...........
(33,713) (5,180) (2,013) -- (23,213)
(64,118) ---------- -------- -------- -
------ -------- ---------- INCOME
BEFORE MINORITY INTEREST AND PROVISION
FOR INCOME TAXES............. 5,147
44,444 14,732 943 (24,663) 40,603
PROVISION FOR INCOME
TAXES............... -- (16,604)
(5,347) -- 16,582 (b) (5,369) ---------
- -------- -------- ------- -------- --
-------- INCOME BEFORE MINORITY
INTEREST.......... 5,147 27,840 9,385
943 (8,081) 35,234 MINORITY
INTEREST....................... (30)
-- -- -- (3,008)(d) (3,038) ----------
-------- -------- ------- -------- ----
------ NET
INCOME...............................
$ 5,117 $ 27,840 $ 9,385 $ 943
$(11,089) $ 32,196 ========== ========
======== ======= ======== ==========
ALLOCATION OF NET INCOME TO: Limited
partners................. $ 1,223 $
26,811(e) $ 28,034 ========== ========
========== General
partner.................. $ 3,894 $
268(e) $ 4,162 ========== ========

========== BASIC EARNINGS PER LIMITED PARTNER UNIT: Number of Units used in computing Basic Earnings per Unit..................... 145,404 145,404 ========== ========== Income before minority interest......... $ 0.01 $ 0.21 ========== ========== Net income per Unit..................... $ 0.01 $ 0.19 ========== ========== DILUTED EARNINGS PER LIMITED PARTNER UNIT: Number of Units used in computing Diluted Earnings per Unit............. 174,404 174,404 ========== ========== Income before minority interest......... $ 0.01 $ 0.18 ========== ========== Net income per Unit..................... $ 0.01 $ 0.16 ========== ==========

ADJUSTMENTS ADJUSTED DUE TO EQUITY ENTERPRISE OFFERING PRO FORMA ------------- ---------- REVENUES Revenues from consolidated operations..... $1,608,214 Equity income in unconsolidated affiliates............................. 16,295 ---------- Total............................. 1,624,509 ---------- COST AND EXPENSES Operating costs and expenses.............. 1,487,900 Selling, general and administrative....... 31,888 ---------- Total............................. 1,519,788 ---------- OPERATING INCOME.......................... 104,721 OTHER INCOME (EXPENSE) Interest expense.......................... (64,157) 3,039(a) Interest income from unconsolidated affiliates............................. 92 Dividend income from unconsolidated affiliates............................. 2,196 Interest income -- other.................. 1,575 Other, net............................... (786) ------- ---------- Other income (expense)............ 3,039 (61,080) ------- ---------- INCOME BEFORE MINORITY INTEREST AND PROVISION FOR INCOME TAXES.............. 3,039 43,642 PROVISION FOR INCOME TAXES................ (5,369) ------- ---------- INCOME BEFORE MINORITY INTEREST........... 3,039 38,273 MINORITY INTEREST........................ (31) (d) (3,068) ------- ---------- NET INCOME............................... $ 3,008 $ 35,205 ======= ========== ALLOCATION OF NET INCOME TO: Limited partners.................. $ 2,978 (e) $ 31,012 ======= ========== General partner................... $ 30 (e) $ 4,192 ======= ========== BASIC EARNINGS PER LIMITED PARTNER UNIT: Number of Units used in computing Basic Earnings per Unit.................... 9,300(a) 154,704 ======= ========== Income before minority interest......... $ 0.22 ========== Net income per Unit.................... $ 0.20 ========== DILUTED EARNINGS PER LIMITED PARTNER UNIT: Number of Units used in computing Diluted Earnings per Unit............ 9,300(a) 183,704 ======= ========== Income before minority interest......... $ 0.19 ========== Net income per Unit.................... $ 0.17 ==========

The accompanying notes are an integral part of these unaudited pro forma condensed financial statements.

ENTERPRISE PRODUCTS PARTNERS L.P.

PRO FORMA STATEMENT OF CONSOLIDATED OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2001
(DOLLARS IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)
(UNAUDITED)

	ENTERPRISE HISTORICAL	MID-AMERICA HISTORICAL	SEMINOLE HISTORICAL	OTHER	ADJUSTMENTS	ENTERPRISE PRO FORMA
REVENUES						
Revenues from consolidated operations....	$3,154,369	$214,518	$ 65,800	$522,669	$ (4,413)(f)	$3,952,943
Equity income in unconsolidated affiliates............................	25,358	--	--	(1,879)		23,479
Total............................	3,179,727	214,518	65,800	520,790	(4,413)	3,976,422
COST AND EXPENSES						
Operating costs and expenses.............	2,861,743	125,349	33,539	507,869	2,230(b) 1,740(c) (4,413)(f)	3,528,057
Selling, general and administrative......	30,296	28,364	1,535	4,477		64,672
Total............................	2,892,039	153,713	35,074	512,346	(443)	3,592,729
OPERATING INCOME.........................	287,688	60,805	30,726	8,444	(3,970)	383,693
OTHER INCOME (EXPENSE)						
Interest expense.........................	(52,456)	(12,700)	(5,160)	--	8,400(b) (53,418)(a) (8,994)(c)	(124,328)
Interest income from unconsolidated affiliates............................	31	--	--	4		35
Dividend income from unconsolidated affiliates............................	3,462	--	--	--		3,462
Interest income -- other.................	7,029	--	--	--		7,029
Other, net...............................	(1,104)	(1,035)	662	(15)		(1,492)
Other income (expense)...........	(43,038)	(13,735)	(4,498)	(11)	(54,012)	(115,294)
INCOME BEFORE MINORITY INTEREST AND PROVISION FOR INCOME TAXES.............	244,650	47,070	26,228	8,433	(57,982)	268,399
PROVISION FOR INCOME TAXES...............	--	(17,445)	(9,470)	--	17,402(b)	(9,513)
INCOME BEFORE MINORITY INTEREST..........	244,650	29,625	16,758	8,433	(40,580)	258,886
MINORITY INTEREST........................	(2,472)	--	--	--	(4,746)(d)	(7,218)
NET INCOME...............................	$ 242,178	$ 29,625	$ 16,758	$ 8,433	$(45,326)	$ 251,668

ALLOCATION OF NET INCOME

TO: Limited partners................ $ 236,570 $ 9,403(e) $ 245,973 ========== ======== ========== General partner................. $ 5,608 $ 87(e) $ 5,695 ========== ======== ========== BASIC EARNINGS PER LIMITED PARTNER UNIT: Number of Units used in computing Basic Earnings per Unit.................... 139,452 139,452 ========== ========== Income before minority interest........ $ 1.72 $ 1.82 ========== ========== Net income per Unit................... $ 1.70 $ 1.76 ========== ========== DILUTED EARNINGS PER LIMITED PARTNER UNIT: Number of Units used in computing Diluted Earnings per Unit........... 170,786 170,786 ========== ========== Income before minority interest........ $ 1.40 $ 1.48 ========== ========== Net income per Unit................... $ 1.39 $ 1.44 ========== ========== ADJUSTMENTS ADJUSTED DUE TO EQUITY ENTERPRISE OFFERING PRO FORMA -------- ----- ---------- REVENUES Revenues from consolidated operations.... $3,952,943 Equity income in unconsolidated affiliates............................ 23,479 ---------- Total........................... 3,976,422 ---------- COST AND EXPENSES Operating costs and expenses............ 3,528,057 Selling, general and administrative...... 64,672 ---------- Total........................... 3,592,729 ---------- OPERATING INCOME........................ 383,693 OTHER INCOME (EXPENSE) Interest expense........................ (118,250) 6,078(a) Interest income from unconsolidated affiliates............................ 35 Dividend income from unconsolidated affiliates............................ 3,462 Interest income -- other................ 7,029 Other, net.............................. (1,492) ------- ---------- Other income (expense).......... 6,078 (109,216) ------- ---------- INCOME BEFORE MINORITY INTEREST AND PROVISION FOR INCOME TAXES............. 6,078 274,477 PROVISION FOR INCOME TAXES............... (9,513) ------- ---------- INCOME BEFORE MINORITY INTEREST.......... 6,078 264,964 MINORITY INTEREST....................... (61) (d) (7,279) ------- ---------- NET INCOME.............................. $ 6,017 $ 257,685 ======= ========== ALLOCATION OF NET INCOME TO: Limited partners................. $ 5,957(e) $ 251,930 ======= ========== General partner................. $ 60(e) $ 5,755 ======= ========== BASIC EARNINGS PER LIMITED PARTNER UNIT: Number of Units used in computing Basic Earnings per Unit................... 9,300(a) 148,752 ======= ========== Income before minority interest........ $ 1.74 ========== Net income per Unit................... $ 1.69 ========== DILUTED EARNINGS PER LIMITED PARTNER UNIT: Number of Units used in computing Diluted Earnings per

Unit............ 9,300(a) 180,086
======= ========== Income before
minority interest........ $ 1.44
========== Net income per
Unit.................... $ 1.40
==========

The accompanying notes are an integral part of these unaudited pro forma condensed financial statements.

ENTERPRISE PRODUCTS PARTNERS L.P.

PRO FORMA CONSOLIDATED BALANCE SHEET AT JUNE 30, 2002
(DOLLARS IN THOUSANDS, UNAUDITED)

ADJUSTMENTS ENTERPRISE MID-
AMERICA SEMINOLE DUE TO EQUITY
ADJUSTED HISTORICAL HISTORICAL
HISTORICAL ADJUSTMENTS PRO FORMA
OFFERING PRO FORMA ---------- --
--------- ---------- -----------
---------- ------------- -------
--- ASSETS CURRENT ASSETS Cash
and cash equivalents...... $
7,929 $ -- $ 11,160 $
1,195,000(a) $ 19,089 $
187,606(a) $ 19,089 (1,195,000)
(a) 3,829(a) (191,435)(a)
Accounts receivable, net.......
284,021 1,383 9,199 294,603
294,603 Accounts receivable --
affiliates..... 1,740 20,506
7,791 (16,333)(f) 13,704 13,704
Income taxes -- affiliates.....
11,855 1,637 (13,492)(b) -- --
Inventories...................
153,280 10,210 -- 163,490
163,490 Prepaid and other
current
assets......................
34,089 868 122 15,000(a) 50,079
50,079 ---------- -------- -----
--- ----------- ---------- -----
---- ---------- Total current
assets..... 481,059 44,822
29,909 (14,825) 540,965 --
540,965 ---------- -------- ----
---- ----------- ---------- ----
----- ---------- PROPERTY, PLANT
AND EQUIPMENT,
NET...........................
1,570,571 633,937 249,390
426,766(b) 2,880,664 2,880,664
INVESTMENTS IN AND ADVANCES TO
UNCONSOLIDATED AFFILIATES......
403,070 -- -- 403,070 403,070
INTANGIBLE
ASSETS................ 249,222 -
- -- 249,222 249,222
GOODWILL........................
81,543 -- -- 81,543 81,543 OTHER
ASSETS....................
6,911 2,844 440 10,195 10,195 --
-------- -------- -------- -----
------ ---------- --------- ----
------ TOTAL...................
$2,792,376 $681,603 $279,739 $
411,941 $4,165,659 $ --
$4,165,659 ========== ========
======== ========== ==========
========= ========== LIABILITIES
AND EQUITY CURRENT LIABILITIES
Current maturities of debt.....
$ -- $ -- $ 15,000 $
1,200,000(a) $1,215,000
$(191,435)(a) $1,023,565
Accounts payable -- trade......
70,716 5,178 2,389 78,283 78,283
Accounts payable --
affiliates........ 21,233 26,726
17,948 (16,333)(f) 49,574 49,574
Accrued gas payables...........
303,983 -- -- 303,983 303,983
Accrued expenses..............
12,961 7,777 2,665 23,403 23,403
Accrued interest..............
24,676 2,100 668 (2,100)(b)
25,344 25,344 Other current

liabilities...... 70,672 368
1,185 72,225 72,225 ---------- -
------- -------- ----------- ---
------- --------- ----------
Total current
liabilities........... 504,241
42,149 39,855 1,181,567
1,767,812 (191,435) 1,576,377 --
-------- -------- -------- -----
------ ---------- --------- ----
------ LONG-TERM
DEBT..................
1,223,552 90,000 45,000
10,000(a) 1,278,552 1,278,552
(90,000)(b) DEFERRED INCOME
TAXES........... -- 122,611
59,116 (181,727)(b) -- -- OTHER
LONG-TERM LIABILITIES......
7,919 384 -- 8,303 8,303
MINORITY
INTEREST................ 10,818
-- -- 54,328(b) 65,146 1,934(a)
67,080 COMMITMENTS AND
CONTINGENCIES OWNERS'
EQUITY.................. --
426,459 135,768 (562,227)(b) --
-- PARTNERS' EQUITY Limited
partners..............
1,051,956 1,051,956 187,606(a)
1,239,562 General
partner................ 10,626
10,626 1,895(a) 12,521 Treasury
Units................. (16,736)
(16,736) (16,736) ---------- ---
----- -------- ----------- -----
----- --------- ---------- Total
Equity............ 1,045,846
426,459 135,768 (562,227)
1,045,846 189,501 1,235,347 ----
------ -------- -------- -------
---- ---------- --------- ------
---- TOTAL...................
$2,792,376 $681,603 $279,739 $
411,941 $4,165,659 $ --
$4,165,659 ========== ========
======== =========== ==========
========= ==========

The accompanying notes are an integral part of these unaudited pro forma condensed financial statements.

NOTES TO UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001 AND JUNE 30, 2002

These unaudited pro forma consolidated financial statements and underlying pro forma adjustments are based upon currently available information and certain estimates and assumptions made by us; therefore, actual results will differ from pro forma results. However, we believe the assumptions provide a reasonable basis for presenting the significant effects of the acquisitions noted herein and the offering of common units. We believe the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the pro forma financial information.

(a) This group of pro forma adjustments reflects the following:

- The net cash proceeds of $1.195 billion needed to acquire our interests in Mid-America and Seminole consisting of a $1.2 billion borrowing under the Term Loan, a $10 million borrowing under our revolving credit facilities, less $15 million in prepaid loan costs.

- The sale of 9,300,000 Common Units at an assumed price of $21.00 per unit. The estimated net proceeds from this offering are $187.6 million after deducting underwriting discounts and commissions of approximately $6.7 million and offering expenses of approximately $1.0 million. The underwriters will receive no discount or commission on the sale of up to 1,810,000 common units to our senior management and their affiliates. In connection with this offering, our general partner will make a capital contribution of $3.8 million to the Company to maintain its approximate 2% combined general partner interest in the Company. The combined proceeds of $191.4 million from the equity offering and the general partner contribution will be used to partially repay the Term Loan.

- An increase in variable rate-based interest expense due to the increase in borrowings. Interest expense also reflects amortization of the $15 million in prepaid loan costs associated with the Term Loan (over its respective one-year life). The combined pro forma increase in interest expense due to these borrowings and amortization was $47.3 million for the year ended December 31, 2001 and $23.7 million for the six months ended June 30, 2002. If the underlying variable interest rate used in such pro forma calculations were to increase by 0.125%, pro forma interest expense would increase by $1.3 million for the year ended December 31, 2001 and by $0.6 million for the six months ended June 30, 2002.

In preparing the pro forma statements of consolidated operations, we have assumed that the net $1.0 billion principal balance of the Term Loan (e.g., the principal balance remaining after application of the offering-related proceeds noted above) is outstanding during the entire period covered by such statements. Our future plans for permanent financing of the Mid-America and Seminole acquisitions include the issuance of additional equity and debt in amounts which are consistent with our objective of maintaining financial flexibility and an investment grade balance sheet.

To the extent that the proceeds of any future equity offering are again used to reduce the principal amount outstanding under the Term Loan, our interest expense will be reduced. To the extent that the Term Loan is refinanced with debt, our interest expense will generally be affected by any difference in interest rates on the Term Loan and the new debt and by any fees associated with the new debt.

(b) This group of pro forma adjustments primarily reflects our preliminary allocation of the $1.195 billion purchase price of our ownership interests in Mid-America and Seminole. The pro forma estimated allocation of the purchase price for Mid-America and Seminole is as follows:

	PRELIMINARY ALLOCATION OF PURCHASE PRICE FOR		
	MID-AMERICA	SEMINOLE	TOTAL
Cash and cash equivalents	$ --	$ 11,160	$ 11,160
Accounts receivable	21,889	16,990	38,879
Product inventory	10,210	--	10,210
Prepaids and other current assets	868	122	990
Property, plant and equipment	957,408	352,684	1,310,093
Other assets	2,844	440	3,284
Accounts payable	(31,904)	(20,337)	(52,241)
Accrued taxes	(7,777)	(2,665)	(10,442)
Other current liabilities	(368)	(1,853)	(2,221)
Long-term debt	--	(60,000)	(60,000)
Other long-term liabilities	(384)	--	(384)
Minority interest in assets and liabilities	(12,586)	(41,741)	(54,328)
Total	$940,200	$254,800	$1,195,000

In preparing these pro forma financial statements, we have assumed that the estimated $426.8 million difference between the purchase price of the assets acquired and liabilities assumed in the Mid-America and Seminole acquisitions (or $1.195 billion) and their respective carrying values (an adjusted $768.2 million after deducting for $54.3 million of minority interest) is attributable to the fair market value of property, plant and equipment. For purposes of calculating pro forma depreciation expense, we have applied the straight-line method using an estimated remaining useful life of the Mid-America and Seminole assets of 35 years to our new basis in these assets of $1.3 billion. After adjusting for historical depreciation recorded on Mid-America and Seminole, pro forma depreciation expense increased $2.2 million for the year ended December 31, 2001 and $1.3 million for the six months ended June 30, 2002.

We are currently working with third-party business valuation experts to develop a definitive allocation of the purchase price. This fair market value study will not be complete until the fourth quarter of 2002. As a result, the final purchase price allocation may result in some amounts being assigned to intangible assets and/or goodwill. To the extent that any amount is assigned to an intangible asset, this amount may ultimately be amortized to earnings over the expected period of benefit of the intangible asset. To the extent that any amount is assigned to goodwill, this amount would not be subject to depreciation or amortization, but would be subject to periodic impairment testing and if necessary, written down to fair value should circumstances warrant.

Other significant aspects of this group of pro forma adjustments are as follows:

- The pro forma adjustment to minority interest of $54.3 million is based on the 2% interest in Mid-America and Seminole owned by Williams and the 20% interest in Seminole owned by its other joint owners.

- The pro forma adjustments also include those associated with the extinguishment of Mid-America's $90 million in private placement debt (along with its associated $2.1 million interest payable) immediately prior to our purchase of the Mid-America interest. The pro forma entries give effect to

the removal of interest expense associated with this debt of $8.4 million in 2001 and $4.1 million for the first six months of 2002.

- In connection with the Mid-America acquisition, immediately prior to the acquisition's effective date Williams converted Mid-America from a corporation to a limited liability company resulting in the recognition of the historical cumulative temporary differences previously recorded on Mid-America's books. In addition, our allocation of purchase price for both book and tax purposes was the same, thus eliminating the need to set up any new cumulative temporary differences on Mid-America's books. The pro forma adjustments reflect this change in Mid-America's tax structure by eliminating these historical tax-related account balances. The impact on Mid-America's pro forma earnings was the elimination of $17.4 million in income tax expense for the year ended December 31, 2001 and $16.6 million for the six months ended June 30, 2002. This pro forma adjustment removed income taxes due from affiliates of $11.8 million and deferred income taxes for $122.6 million from Mid-America's balance sheet.

- In connection with the Seminole acquisition, certain tax elections were made by the buyer and seller such that the transaction was treated as an asset purchase for tax purposes. Our allocation of purchase price for both book and tax purposes was the same, thus eliminating any historical cumulative temporary differences previously recorded on Seminole's books. The pro forma adjustments reflect the elimination of these historical deferred tax balances. This pro forma adjustment removed income taxes due from affiliates of $1.6 million and deferred income taxes of $59.1 million from Seminole's balance sheet.

(c) Since January 1, 2001, we have acquired three other strategic businesses that are incorporated into the pro forma statements of consolidated operations (included under the "Other" column in these statements). These are the acquisition of a natural gas pipeline business from Shell during the second quarter of 2001 and the acquisition of a propylene fractionation business and NGL and petrochemical storage business from Diamond-Koch during the first quarter of 2002. Our June 30, 2002 historical balance sheet already reflects these acquisitions; thus, no pro forma adjustments to the balance sheet are necessary. The unaudited pro forma statements of consolidated operations have been prepared as if these acquisitions had occurred on January 1 of the respective periods presented.

This group of pro forma adjustments reflects the following:

- As a result of the Diamond-Koch business acquisitions, we acquired certain contract-based intangible assets that are subject to amortization. On a pro forma basis, amortization expense associated with these intangible assets increased by $1.7 million for the year ended December 31, 2001 and $0.1 million for the six months ended June 30, 2002.

- Of the cumulative $612.3 million paid to acquire these three businesses, the natural gas pipeline business acquired from Shell and the propylene fractionation business acquired from Diamond-Koch were financed using $482.2 million of fixed and variable rate debt. This resulted in pro forma interest expense of $9.0 million for the year ended December 31, 2001 and $0.7 million for the six months ended June 30, 2002. If the variable-interest rate used in such pro forma calculations were to increase by 0.125%, pro forma interest expense would increase by $0.3 million for the year ended December 31, 2001 and by less than $0.1 million for the six months ended June 30, 2002.

(d) Represents the allocation of pro forma earnings to minority interest holders. Williams has a 2% minority interest in Mid-America and Seminole. The other owners of Seminole hold a 20% minority interest. Finally, our general partner holds an approximate 1% minority interest in the earnings of our Operating Partnership.

(e) Represents the adjustments necessary to allocate pro forma earnings between our limited partners and our general partner.

(f) Reflects the elimination of material intercompany receivables, payables, revenues and expenses between acquired companies and our Company as appropriate in consolidation.

INDEPENDENT AUDITORS' REPORT

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, 2001 and 2000, and the related statements of consolidated operations, consolidated cash flows and consolidated partners' equity for each of the years in the three-year period ended December 31, 2001. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements 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, 2001 and 2000, and the results of its consolidated operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 13 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments in 2001.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 8, 2002
(May 15, 2002 as to Note 16 for the effects of a two-for-one split of Limited Partner Units)

ENTERPRISE PRODUCTS PARTNERS L.P.

STATEMENTS OF CONSOLIDATED OPERATIONS
(DOLLARS IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)

FOR YEAR ENDED DECEMBER 31,	2001	2000	1999
REVENUES			
Revenues from consolidated operations....................	$3,154,369	$3,049,020	$1,332,979
Equity income in unconsolidated affiliates...............	25,358	24,119	13,477
Total...	3,179,727	3,073,139	1,346,456
COST AND EXPENSES			
Operating costs and expenses...........................	2,861,743	2,801,060	1,201,605
Selling, general and administrative.....................	30,296	28,345	12,500
Total...	2,892,039	2,829,405	1,214,105
OPERATING INCOME..	287,688	243,734	132,351
OTHER INCOME (EXPENSE)			
Interest expense.......................................	(52,456)	(33,329)	(16,439)
Interest income from unconsolidated affiliates...........	31	1,787	1,667
Dividend income from unconsolidated affiliates...........	3,462	7,091	3,435
Interest income -- other................................	7,029	3,748	886
Other, net...	(1,104)	(272)	(379)
Other income (expense)........................	(43,038)	(20,975)	(10,830)
INCOME BEFORE MINORITY INTEREST.........................	244,650	222,759	121,521
MINORITY INTEREST.......................................	(2,472)	(2,253)	(1,226)
NET INCOME..	$ 242,178	$ 220,506	$ 120,295
ALLOCATION OF NET INCOME TO:			
Limited partners..............................	$ 236,570	$ 217,909	$ 119,092
General partner...............................	$ 5,608	$ 2,597	$ 1,203
BASIC EARNINGS PER UNIT			
Income before minority interest................	$ 1.72	$ 1.64	$ .90
Net income per Common and Subordinated unit....	$ 1.70	$ 1.63	$ .90
DILUTED EARNINGS PER UNIT			
Income before minority interest................	$ 1.40	$ 1.34	$ .83
Net income per Common, Subordinated and Special unit......................................	$ 1.39	$ 1.32	$ .82

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS
(DOLLARS IN THOUSANDS)

DECEMBER 31,	2001	2000
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents (includes restricted cash of $5,752 at December 31, 2001)	$ 137,823	$ 60,409
Accounts receivable -- trade, net of allowance for doubtful accounts of $20,642 at December 31, 2001 and $10,916 at December 31, 2000	256,927	409,085
Accounts receivable -- affiliates	4,375	6,533
Inventories	69,443	93,222
Prepaid and other current assets	50,207	12,107
Total current assets	518,775	581,356
PROPERTY, PLANT AND EQUIPMENT, NET	1,306,790	975,322
INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES	398,201	298,954
INTANGIBLE ASSETS, NET OF ACCUMULATED AMORTIZATION OF $13,084 AT DECEMBER 31, 2001 AND $5,374 AT DECEMBER 31, 2000	202,226	92,869
OTHER ASSETS	5,201	2,867
TOTAL	$2,431,193	$1,951,368
LIABILITIES AND PARTNERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable -- trade	$ 54,269	$ 96,559
Accounts payable -- affiliates	29,885	56,447
Accrued gas payables	233,536	377,126
Accrued expenses	22,460	21,488
Accrued interest	24,302	10,068
Other current liabilities	44,764	24,691
Total current liabilities	409,216	586,379
LONG-TERM DEBT	855,278	403,847
OTHER LONG-TERM LIABILITIES	8,061	15,613
MINORITY INTEREST	11,716	9,570
COMMITMENTS AND CONTINGENCIES		
PARTNERS' EQUITY		
Common Units (102,721,830 Units outstanding at December 31, 2001 and 92,514,630 at December 31, 2000)	651,872	514,896
Subordinated Units (42,819,740 Units outstanding at December 31, 2001 and December 31, 2000)	193,107	165,253
Special Units (29,000,000 Units outstanding at December 31, 2001 and 33,000,000 at December 31, 2000)	296,634	251,132
Treasury Units acquired by Trust, at cost (327,200 Common Units outstanding at December 31, 2001 and 534,400 at December 31, 2000)	(6,222)	(4,727)
General Partner	11,531	9,405
Total Partners' Equity	1,146,922	935,959
TOTAL	$2,431,193	$1,951,368

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

STATEMENTS OF CONSOLIDATED CASH FLOWS
(DOLLARS IN THOUSANDS)

	FOR YEAR ENDED DECEMBER 31,		
	2001	2000	1999
OPERATING ACTIVITIES			
Net income	$ 242,178	$ 220,506	$ 120,295
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:			
Depreciation and amortization	51,903	41,045	25,315
Equity in income of unconsolidated affiliates	(25,358)	(24,119)	(13,477)
Distributions received from unconsolidated affiliates	45,054	37,267	6,008
Leases paid by EPCO	10,309	10,537	10,557
Minority interest	2,472	2,253	1,226
Loss (gain) on sale of assets	(390)	2,270	123
Changes in fair market value of financial instruments (see Note 13)	(5,697)		
Net effect of changes in operating accounts	(37,143)	71,111	27,906
Operating activities cash flows	283,328	360,870	177,953
INVESTING ACTIVITIES			
Capital expenditures	(149,896)	(243,913)	(21,234)
Proceeds from sale of assets	568	92	8
Business acquisitions, net of cash received	(225,665)		(208,095)
Collection of notes receivable from unconsolidated affiliates		6,519	19,979
Investments in and advances to unconsolidated affiliates	(116,220)	(31,496)	(61,887)
Investing activities cash flows	(491,213)	(268,798)	(271,229)
FINANCING ACTIVITIES			
Long-term debt borrowings	449,717	598,818	350,000
Long-term debt repayments		(490,000)	(154,923)
Debt issuance costs	(3,125)	(4,043)	(3,135)
Cash distributions paid to partners	(164,308)	(139,577)	(111,758)
Cash distributions paid to minority interest by Operating Partnership	(1,687)	(1,429)	(1,140)
Unit repurchased and retired		(770)	
Cash contributions from EPCO to minority interest	105	108	86
Treasury Units purchased by Trust	(18,003)		(4,727)
Treasury Units reissued by Trust	22,600		
Increase in restricted cash	(5,752)		
Financing activities cash flows	279,547	(36,893)	74,403
NET CHANGE IN CASH AND CASH EQUIVALENTS	71,662	55,179	(18,873)
CASH AND CASH EQUIVALENTS, JANUARY 1	60,409	5,230	24,103
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 132,071	$ 60,409	$ 5,230

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(DOLLARS IN THOUSANDS)

LIMITED PARTNERS ----------------------------
--- COMMON SUBORD. SPECIAL TREASURY GENERAL
UNITS UNITS UNITS UNITS PARTNER TOTAL -------
-- -------- -------- -------- ------- -------
--- Balance, December 31,
1998......................... $ 433,082
$123,829 $ 5,625 $ 562,536 Net
income.......................................
80,998 38,094 1,203 120,295 Leases paid by
EPCO.............................. 7,109
3,342 106 10,557 Special Units issued to
Shell in connection with TNGL
acquisition..............................
$210,436 2,126 212,562 Cash distributions to
Unitholders................. (81,993)
(28,647) (1,118) (111,758) Treasury Units
acquired by consolidated Trust..... $(4,727)
(4,727) --------- -------- -------- ------- -
------ ---------- 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 Additional Special Units
issued to Shell in connection with
contingency agreement........... 55,241 557
55,798 Conversion of 2.0 million Shell
Special Units into Common
Units...................................
14,513 (14,513) -- Units repurchased and
retired in connection with buy-back
program................................ (687)
(43) (32) (8) (770) Cash distributions to
Unitholders................. (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 Additional Special Units
issued to Shell in connection with
contingency agreement........... 117,066
1,183 118,249 Conversion of 10.0 million
Shell Special Units into Common
Units.............................. 72,554
(72,554) Cash distributions to
Unitholders................. (109,969)
(49,510) (4,829) (164,308) 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............................. 3,518
1,461 990 61 6,030 --------- -------- -------
- ------- ------- ---------- Balance,
December 31, 2001......................... $
651,872 $193,107 $296,634 $(6,222) $11,531
$1,146,922 ========= ======== ========
======= ======= ==========

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ENTERPRISE PRODUCTS PARTNERS L.P. including its consolidated subsidiaries is a publicly-traded Delaware limited partnership listed on the New York Stock Exchange under symbol "EPD". Unless the context requires otherwise, references to "we","us","our" or the "Company" 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. The Common Units sold for $11 per unit. We received approximately $243.3 million net of underwriting commissions and offering costs.

The accompanying consolidated financial statements include the historical accounts and operations of the NGL business of EPCO, including NGL operations conducted by affiliated companies of EPCO prior to their consolidation with EPCO. The consolidated financial statements include our accounts and those of our majority-owned subsidiaries, after elimination of all material intercompany accounts and transactions. In general, 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.

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.

FINANCIAL INSTRUMENTS such as swaps, forwards and other contracts to manage the price risks associated with inventories, firm commitments and certain anticipated transactions are used by the Company. We are required to recognize in earnings changes in fair value of these financial instruments that are not offset by changes in the fair value of the inventories, firm commitments and certain anticipated transactions. 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.

The effective portion of these hedged transactions will be deferred until the firm commitment or anticipated transaction affects 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 that exposure and meet the hedging requirements of SFAS No. 133. Any contracts held or issued that do not meet the requirements of a hedge (as defined by SFAS No. 133) will be recorded at fair value on the balance sheet and any changes in that fair value recognized in earnings (using mark-to-market accounting). A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

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. See Notes 7 and 8 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, 2001 were not significant to the consolidated financial statements. Costs of environmental compliance and monitoring aggregated $1.3 million, $1.3 million and $0.9 million for the years ended December 31, 2001, 2000 and 1999, 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 K/D/S Promix L.L.C., Dixie Pipeline Company, Neptune Pipeline Company L.L.C. and Nemo Pipeline Company, LLC. The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. See Note 4 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 inventory, and volumes loaned to us under such agreements are accrued as a liability in accrued gas payables.

FEDERAL INCOME TAXES are not provided because we are a master limited partnership. As a result, our earnings or losses for Federal income tax purposes are included in the tax returns of the individual partners. Accordingly, no recognition has been given to income taxes in our financial statements. State income taxes are not material to us. 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.

INVENTORIES are valued at the lower of average cost or market (normal trade inventories of natural gas, NGLs and petrochemicals) or using specific identification (volumes dedicated to forward sales contracts).

INTANGIBLE ASSETS include the values assigned to a 20-year natural gas processing agreement and the excess cost of the purchase price over the fair market value of the assets acquired from Mont Belvieu Associates (the "MBA excess cost"), both of which were initially recorded in 1999. Of the intangible values at December 31, 2001, $194.4 million is assigned to the natural gas processing agreement and is being amortized on a straight-line basis over the contract term.

The remaining $7.9 million balance of intangibles relates to the MBA excess cost which has been amortized on a straight-line basis over 20 years. Upon adoption of SFAS No. 142 on January 1, 2002, this amount was reclassified to goodwill and will no longer be amortized but will be subject to periodic impairment testing in accordance with the new standard. For additional information regarding this reclassification and other details pertaining to the adoption of SFAS No. 142, see Note 5.

LONG-LIVED ASSETS 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.

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, and 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 referred to as expansion capital expenditures.

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

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. 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.

In our Fractionation segment, we enter into NGL fractionation, isomerization and propylene fractionation tolling arrangements, NGL fractionation in-kind contracts and propylene fractionation merchant contracts. Under our tolling arrangements, we recognize revenue once contract services have been performed. These tolling arrangements typically include a base processing fee per gallon subject to adjustment for changes in natural gas, electricity and labor costs, which are the principal variable costs of fractionation and isomerization operations. At our Norco NGL fractionation facility, certain tolling arrangements involves the retention of a contractually-determined percentage of the NGLs produced for the processing customer in lieu of a cash tolling fee per gallon (i.e., an "in-kind" fee). We recognize revenue from these in-kind contracts when we sell (at market-related prices) and deliver the NGLs retained by our fractionator to customers. In our propylene fractionation merchant contracts, we recognize revenue once the products have been delivered to the customer. These merchant contracts are based upon market-related prices as determined by the individual contracts.

In our Pipelines segment, we enter into pipeline, storage and product loading contracts. Under our liquids pipeline 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 the Federal Energy Regulatory Commission ("FERC"). Additionally, we have merchant contracts associated with our natural gas pipeline business whereby revenue is recognized once a quantity of natural gas has been delivered to a customer. These merchant contracts are based upon market-related prices as determined by the individual contracts.

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 loading contracts (applicable to EPIK, an unconsolidated affiliate of the Company) are recorded once the loading services have been performed with the loading rates stated in the individual contracts.

As part of our Processing business, we have entered into a significant 20-year natural gas processing agreement with Shell ("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 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 contract stipulates that we retain a percentage of the NGLs extracted as payment for its services, revenue is recorded when the NGLs are sold and delivered to third parties. The Processing segment's merchant activities may also buy and sell NGLs in the open market (including forward sales contracts). The revenues recorded for these contracts are recognized upon the delivery of the products specified in each individual contract. Pricing under both types of arrangements is based upon market-related prices plus or minus other determining factors specific to each contract such as location pricing differentials.

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. 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. Revenue is recognized once the product has been delivered to Sun.

The Other segment is primarily comprised of 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 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. BUSINESS ACQUISITIONS

ACQUISITION OF ACADIAN GAS IN APRIL 2001

On April 2, 2001, we acquired Acadian Gas from an affiliate of Shell, for approximately $226 million in cash using proceeds from the issuance of the $450 million Senior Notes B (see Note 6). Acadian Gas 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. Acadian Gas owns an approximate 49.5% of Evangeline which owns a 27-mile natural gas pipeline. We operate the systems. Overall, the Acadian Gas and Evangeline systems are comprised of 1,042 miles of pipeline with an optimal design capacity of 1.1 Bcf/d.

The Acadian Gas and Evangeline systems link supplies of natural gas from Gulf of Mexico production (through connections with offshore pipelines) and various onshore developments to industrial, electrical and local distribution customers primarily located in Louisiana. In addition, these systems have interconnects with twelve interstate and four intrastate pipelines and a bi-directional interconnect with the U.S. natural gas marketplace at the Henry Hub.The Acadian Gas acquisition was accounted for under the purchase method of accounting and, accordingly, the initial purchase price has been allocated to the assets acquired and liabilities assumed based on their estimated fair values at April 1, 2001 as follows (in millions):

Current assets	$ 83,123
Investments in unconsolidated affiliates	2,723
Property, plant and equipment	225,169
Current liabilities	(83,890)
Other long-term liabilities	(1,460)
Total purchase price	$225,665

The balances related to the Acadian Gas acquisition included in the consolidated balance sheet dated December 31, 2001 are based upon preliminary information and are subject to change as additional information is obtained. The initial purchase price is subject to certain post-closing adjustments attributable to working capital items and is expected to be finalized during the first half of 2002.

Historical information for periods prior to April 1, 2001 do not reflect any impact associated with the Acadian Gas acquisition.

PRO FORMA EFFECT OF BUSINESS COMBINATIONS

The following table presents selected unaudited pro forma information for the years ended December 31, 2001 and 2000 as if the acquisition of Acadian Gas had been made as of the beginning of the years presented. This table also incorporates selected unaudited pro forma information for the year ended December 31, 2000 relating to our equity investments in Starfish and Neptune (see Note 4).

The pro forma information is based upon data currently available to and certain estimates and assumptions by management and, as a result, are 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,	
	2001	2000
Revenues	$3,391,654	$3,673,049
Income before extraordinary item and minority interest	$ 248,934	$ 217,223
Net income	$ 246,419	$ 215,026
Allocation of net income to Limited partners	$ 240,745	$ 212,483
General Partner	$ 5,674	$ 2,542
Units used in earnings per Unit calculations		
Basic	139,452	134,216
Diluted	170,786	164,888
Income per Unit before minority interest		
Basic	$ 1.75	$ 1.60
Diluted	$ 1.43	$ 1.30
Net income per Unit		
Basic	$ 1.73	$ 1.59
Diluted	$ 1.41	$ 1.29

3. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment and accumulated depreciation are as follows:

	ESTIMATED USEFUL LIFE IN YEARS	2001	2000
Plants and pipelines	5-35	$1,398,843	$1,108,519
Underground and other storage facilities	5-35	127,900	109,760
Transportation equipment	3-35	3,736	2,620
Land		15,517	14,805
Construction in progress		98,844	34,358
Total		1,644,840	1,270,062
Less accumulated depreciation		338,050	294,740
Property, plant and equipment, net		$1,306,790	$ 975,322

Depreciation expense for the years ended December 31, 2001, 2000 and 1999 was $43.4 million, $33.3 million and $22.4 million, respectively. The increase in depreciation expense is primarily due to acquisitions and expansion capital projects over the last three years.

4. 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 operating segments, see Note 15.

The following table shows investments in and advances to unconsolidated affiliates at:

	DECEMBER 31, 2001	DECEMBER 31, 2000
Accounted for on equity basis:		
Fractionation:		
BRF	$ 29,417	$ 30,599
BRPC	18,841	25,925
Promix	45,071	48,670
Pipeline:		
EPIK	14,280	15,998
Wilprise	8,834	9,156
Tri-States	26,734	27,138
Belle Rose	11,624	11,653
Dixie	37,558	38,138
Starfish	25,352	
Neptune	76,880	
Nemo	12,189	
Evangeline	2,578	
Octane Enhancement:		
BEF	55,843	58,677
Accounted for on cost basis:		
Processing:		
VESCO	33,000	33,000
Total	$398,201	$298,954

The following table shows equity in income (loss) of unconsolidated affiliates for the year ended December 31:

	FOR YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Fractionation:			
BRF	$ 1,583	$ 1,369	$ (336)
BRPC	1,161	(284)	16
Promix	4,201	5,306	630
Other			1,256
Pipeline:			
EPIK	345	3,273	1,173
Wilprise	472	497	160
Tri-States	1,565	2,499	1,035
Belle Rose	103	301	(29)
Dixie	2,092	751	
Starfish	4,122		
Ocean Breeze	32		
Neptune	4,081		
Nemo	75		
Evangeline	(145)		
Other			1,389
Octane Enhancement:			
BEF	5,671	10,407	8,183
Total	$25,358	$24,119	$13,477

At December 31, 2001, our share of accumulated earnings of equity method unconsolidated affiliates that had not been remitted to us was approximately $7.0 million.

FRACTIONATION SEGMENT:

At December 31, 2001, 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 fractionation facility located in southeastern Louisiana.

- Baton Rouge Propylene Concentrator, LLC ("BRPC") -- a 30.0% interest in a propylene concentration unit located in southeastern Louisiana.

- K/D/S Promix LLC ("Promix") -- a 33.33% interest in an NGL fractionation facility and related storage assets located in south Louisiana. Our investment includes excess cost over the underlying equity in the net assets of Promix of $8.0 million. The excess cost, which relates to plant assets, is being amortized against our share of Promix's earnings over a period of 20 years, which is the estimated useful life of the plant assets that gave rise to the difference. The unamortized balance of excess cost was $7.0 million at December 31, 2001.

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 used in the following tables, gross operating margin for equity investments represents operating income before depreciation and amortization expense (both on operating assets) and selling, general and administrative costs.

AS OF OR FOR THE YEAR ENDED DECEMBER 31,	2001	2000	1999
BALANCE SHEET DATA:			
Current Assets	$ 27,424	$ 31,168	
Property, plant and equipment, net	251,519	264,618	
Other assets		67	
Total assets	$278,943	$295,853	
Current liabilities	$ 9,950	$ 13,661	
Combined equity	268,993	282,192	
Total liabilities and combined equity	$278,943	$295,853	
INCOME STATEMENT DATA:			
Revenues	$ 76,480	$ 71,287	$ 36,293
Gross operating margin	36,321	33,240	14,970
Operating income	22,396	19,997	5,930
Net income	22,738	20,661	4,200

PIPELINES SEGMENT:

At December 31, 2001, 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 a refrigerated NGL marine terminal loading facility located in southeast Texas. The Company owns 50% of EPIK Terminalling L.P. which owns 99% of such facilities. We own 50% of EPIK Gas Liquids, LLC which owns 1% of such facilities. We do not exercise control over these entities; therefore, we are precluded from consolidating such entities into 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. Our investment includes excess cost over the underlying equity in the net assets of Dixie of $37.4 million. The excess cost, which relates to pipeline assets, is being amortized against our share of Dixie's earnings over a period of 35 years, which is the estimated useful life of the pipeline assets that gave rise to the difference. The unamortized balance of excess cost over the underlying equity in the net assets of Dixie was $35.7 million at December 31, 2001.

- 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.

- 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. We acquired our interest in Evangeline as a result of the Acadian Gas acquisition (see Note 2 for a description of this acquisition).

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,	2001	2000	1999
BALANCE SHEET DATA:			
Current Assets	$ 68,325	$ 25,464	
Property, plant and equipment, net	515,327	188,724	
Other assets	50,265	3,666	
Total assets	$633,917	$217,854	
Current liabilities	$ 62,347	$ 31,085	
Other liabilities	57,965	4,018	
Combined equity	513,605	182,751	
Total liabilities and combined equity	$633,917	$217,854	
INCOME STATEMENT DATA:			
Revenues	$305,404	$ 96,270	$52,386
Gross operating margin	98,682	51,414	24,845
Operating income	54,459	41,757	19,988
Net income	41,015	31,241	15,637

Equity investments in Gulf of Mexico natural gas pipeline systems in January 2001

On January 29, 2001, we acquired a 50% equity interest in Starfish which owns the Stingray natural gas pipeline system and a related natural gas dehydration facility. The Stingray system is a 379-mile, FERC-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. The natural gas dehydration facility is connected to the onshore terminal of the Stingray system in south Louisiana. The optimal design capacity of the Stingray pipeline is 1.2 Bcf/d. Shell is the operator of these systems and owns the remaining equity interests in Starfish.

In addition to Starfish, we acquired a 25.67% interest in Ocean Breeze Pipeline Company ("Ocean Breeze") and Neptune and a 33.92% interest in Nemo. Ocean Breeze and Neptune collectively owned 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 with an optimal design capacity of 0.75 Bcf/d and the Nautilus system comprises approximately 101 miles of FERC-regulated pipelines with an optimal design capacity of 0.6 Bcf/d. The Nemo system, which became operational in August 2001, comprises 24-mile natural gas pipeline with an optimal design capacity of 0.3 Bcf/d. Like Stingray, Shell is the operator of the Manta Ray and Nemo systems. Shell is the administrative agent for Nautilus. In November 2001, Ocean Breeze was merged into Neptune with the Company retaining its 25.67% interest in Neptune. Shell and Marathon are the co-owners of Neptune and Shell owns the remaining interest in Nemo.

The cash purchase price of the Starfish interest was $25 million with the purchase price of the Ocean Breeze, Neptune and Nemo interests being $87 million. The investments were paid for using proceeds from the issuance of the $450 million Senior Notes B (see Note 6).

Our investment in Neptune and Nemo includes excess cost over the underlying equity in the net assets of these entities of $13.5 million. The excess cost, which relates to pipeline assets, is being amortized against our share of earnings from Neptune and Nemo over a period of 35 years, which is the estimated useful life of the pipeline assets that gave rise to the difference. The unamortized balance of excess cost over the underlying equity in the net assets of Neptune and Nemo was $12.4 million and $0.7 million, respectively, at December 31, 2001.

Historical information for periods prior to January 1, 2001 do not reflect any impact associated with our equity investments in Starfish, Neptune and Nemo.

OCTANE ENHANCEMENT SEGMENT:

At December 31, 2001, 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 reduce the demand for MTBE and could have an adverse effect on our results of operations.

In recent years, MTBE has been detected in water supplies. The major source of the 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.

In light of these regulatory developments, the owners of BEF have been formulating a contingency plan for use of the BEF facility if MTBE were banned or significantly curtailed. Management is exploring a possible conversion of the BEF facility from MTBE production to alkylate production. The Company believes that if MTBE usage is banned or significantly curtailed, the motor gasoline industry would need a substitute additive to maintain octane levels in motor gasoline and that alkylate would be an attractive substitute. Depending upon the type of alkylate process chosen and the level of alkylate production desired, the cost to convert the facility from MTBE production to alkylate production would range from $20 million to $90 million, with our share of these costs ranging from $6.7 million to $30 million.

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,	2001	2000	1999
BALANCE SHEET DATA:			
Current Assets	$ 29,301	$ 20,640	
Property, plant and equipment, net	140,009	150,603	
Other assets	10,067	11,439	
Total assets	$179,377	$182,682	
Current liabilities	$ 13,352	$ 8,042	
Other liabilities	3,438	5,779	
Combined equity	162,587	168,861	
Total liabilities and combined equity	$179,377	$182,682	
INCOME STATEMENT DATA:			
Revenues	$213,734	$258,180	$193,219
Gross operating margin	28,701	43,328	43,479
Operating income	15,984	30,529	30,025
Income before accounting change	17,014	31,220	29,029
Net income	17,014	31,220	24,550

PROCESSING SEGMENT:

At December 31, 2001, 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 Louisiana. We account for this investment using the cost method.

5. RECENTLY ISSUED ACCOUNTING STANDARDS

In June 2001, the FASB issued two new pronouncements: SFAS No. 141, "Business Combinations", and SFAS No. 142, "Goodwill and Other Intangible Assets". SFAS No. 141 prohibits the use of the pooling-of-interest method for business combinations initiated after June 30, 2001 and also applies to all business combinations accounted for by the purchase method that are completed after June 30, 2001. There are also transition provisions that apply to business combinations completed before July 1, 2001, that were accounted for by the purchase method. SFAS No. 142 is effective for our fiscal year that began January 1, 2002 for all goodwill and other intangible assets recognized in our consolidated balance sheet at that date, regardless of when those assets were initially recognized. We adopted SFAS No. 141 on January 1, 2002.

Within six months of our adoption of SFAS No. 142 (by June 30, 2002), we will have completed a transitional impairment review to identify if there is an impairment to the December 31, 2001 recorded goodwill or intangible assets of indefinite life using a fair value methodology. Professionals in the business valuation industry will be consulted to validate the assumptions used in such methodologies. Any impairment loss resulting from the transitional impairment test will be recorded as a cumulative effect of a change in accounting principle for the quarter ended June 30, 2002. Subsequent impairment losses will be reflected in operating income in the Statements of Consolidated Operations.

At January 1, 2002, our intangible assets included the values assigned to the 20-year Shell natural gas processing agreement (the "Shell agreement") and the excess cost of the purchase price over the fair market value of the assets acquired from Mont Belvieu Associates (the "MBA excess cost"), both of which were initially recorded in 1999. The value of the Shell agreement ($194.4 million net book value at December 31, 2001) is being amortized on a straight-line basis over its contract term. Likewise, the MBA excess cost ($7.9 million net book value at December 31, 2001) was being amortized on a straight-line basis over 20 years. Based upon initial interpretations of the new accounting standards, we anticipate that the intangible asset related to the Shell agreement will continue to be amortized over its contract term ($11.1 million annually for 2002 through July 2019); however, the MBA excess cost will be reclassified to goodwill in accordance with the new standard and its amortization will cease (currently, $0.5 million annually). This goodwill would then be subject to impairment testing as prescribed in SFAS No. 142. We are continuing to evaluate the complex provisions of SFAS No. 142 and will fully adopt the standard during 2002 within the prescribed time periods.

In addition to SFAS No. 141 and No. 142, the FASB also issued SFAS No. 143, "Accounting for Asset Retirement Obligations", in June 2001. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. This statement is effective for our fiscal year beginning January 1, 2003. We are continuing to evaluate the provisions of this statement. In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. We adopted this statement effective January 1, 2002 and determined that it will have no material impact on our financial statements as of that date.

6. LONG-TERM DEBT

Our long-term debt consisted of the following at:

DECEMBER 31,	2001	2000
Borrowings under:		
Senior Notes A, 8.25% fixed rate, due March 2005..........	$350,000	$350,000
MBFC Loan, 8.70% fixed rate, due March 2010..............	54,000	54,000
Senior Notes B, 7.50% fixed rate, due February 2011.......	450,000	
Total principal amount...........................	854,000	404,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt.....................	1,653	
Less unamortized discount on: Senior Notes A..	(117)	(153)
Senior Notes B..	(258)	
Less current maturities of long-term debt..................	--	
Long-term debt..................................	$855,278	$403,847

Long-term debt does not reflect the $250 million Multi-Year Credit Facility or the $150 million 364-Day Credit Facility. No amount was outstanding under either of these two revolving credit facilities at December 31, 2001. See below for a complete description of these facilities.

At December 31, 2001, we had a total of $75 million of standby letters of credit capacity under our $250 Million Multi-Year Credit Facility of which $2.4 million was outstanding.

Enterprise Products Partners L.P. acts as guarantor of certain debt obligations of its major subsidiary, the Operating Partnership. This parent-subsidiary guaranty provision exists under the Company's Senior Notes, MBFC Loan and its two current revolving credit facilities. In the descriptions that follow, the term "MLP" denotes Enterprise Products Partners L.P. in this guarantor role.

SENIOR NOTES A. On March 13, 2000, we completed a public offering of $350 million in principal amount of 8.25% fixed-rate Senior Notes due March 15, 2005 at a price to the public of 99.948% per Senior Note (the "Senior Notes A"). These notes were issued to retire certain revolving credit loan balances that were created as a result of the TNGL acquisition and other general partnership activities.

The Senior Notes A are subject to a make-whole redemption right. The notes are an unsecured obligation and rank equally with existing and future unsecured and unsubordinated indebtedness and senior to any future subordinated indebtedness. The notes are guaranteed by the MLP through an unsecured and unsubordinated guarantee and were issued under an indenture containing certain restrictive covenants. These covenants restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. We were in compliance with these restrictive covenants at December 31, 2001.

SENIOR NOTES B. On January 24, 2001, we completed a public offering of $450 million in principal amount of 7.50% fixed-rate Senior Notes due February 1, 2011 at a price to the public of 99.937% per Senior Note (the "Senior Notes B"). These notes were issued to finance the acquisition of Acadian Gas, Ocean Breeze, Neptune, Nemo and Starfish; to cover construction costs of certain NGL pipelines and related projects; and to fund other general partnership activities.

The Senior Notes B were issued under the same indenture as Senior Notes A and therefore are subject to similar terms and restrictive covenants. The Senior Notes B are guaranteed by the MLP through an unsecured and unsubordinated guarantee. We were in compliance with the restrictive covenants at December 31, 2001.

MBFC LOAN. On March 27, 2000, we executed a $54 million loan agreement with the Mississippi Business Finance Corporation ("MBFC") having a 8.70% fixed-rate and a maturity date of March 1, 2010. In general, the proceeds from this loan were used to retire certain revolving credit loan balances attributable to acquiring and constructing the Pascagoula, Mississippi natural gas processing facility.

The MBFC Loan is subject to a make-whole redemption right and is guaranteed by the MLP through an unsecured and unsubordinated guarantee. The indenture agreement contains an acceleration clause whereby the outstanding principal and interest on the loan may become due and payable 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 in the indenture agreement) may, and if requested to do so by holders of at least 25% in aggregate of the principal amount of the outstanding underlying bonds, shall accelerate the maturity of the MBFC Loan, whereby the principal and all accrued interest would become immediately due and payable. If such an event occurred, we would have the option (a) to redeem the MBFC loan or (b) to provide an alternate credit agreement (as defined in the indenture agreement) to support our obligation under the MBFC loan, with both options exercisable within 120 days of receiving notice of the decline in our credit ratings from the ratings agencies.

The loan agreement contains certain covenants including maintaining appropriate levels of insurance on the Pascagoula facility and restrictions regarding mergers. We were in compliance with the restrictive covenants at December 31, 2001.

MULTI-YEAR CREDIT FACILITY. On November 17, 2000, we entered into a $250 million five-year revolving credit facility that includes a sublimit of $75 million for letters of credit. The November 17, 2005 maturity date may be extended for one year at our option with the consent of the lenders, subject to the extension provisions in the agreement. We can increase the amount borrowed under this facility, with the consent of the Administrative Agent (whose consent may not be unreasonably withheld), up to an amount not exceeding $350 million by adding to the facility one or more new lenders and/or increasing the commitments of existing lenders, so long as the aggregate amount of the funds borrowed under this credit facility and the 364-Day

Credit Facility (described below) does not exceed $500 million. No lender will be required to increase its original commitment, unless it agrees to do so at its sole discretion. This credit facility is guaranteed by the MLP through an unsecured guarantee.

Proceeds from this credit facility will be used for working capital, acquisitions and other general partnership purposes. No amount was outstanding for this credit facility at December 31, 2001.

Our obligations under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. As defined within the agreement, borrowings under this bank credit facility will generally bear interest at either (i) the greater of the Prime Rate or the Federal Funds Effective Rate plus one-half percent or (ii) a Eurodollar Rate plus an applicable margin or (iii) a Competitive Bid Rate. We elect the basis for the interest rate at the time of each borrowing.

The credit agreement contains various affirmative and negative covenants applicable to the Company to, among other things, (i) incur certain indebtedness, (ii) grant certain liens, (iii) enter into certain merger or consolidation transactions and (iv) make certain investments. In addition, we may not directly or indirectly make any distribution in respect of its partnership interests, except those payments in connection with the Buy-Back Program (not to exceed $30 million in the aggregate, see Note 7) and distributions from Available Cash from Operating Surplus, both as defined within the agreement.

The credit agreement also requires that we satisfy certain financial covenants at the end of each fiscal quarter. As defined within the agreement, we (i) must maintain Consolidated Net Worth of $750 million and (ii) not permit our ratio of Consolidated Indebtedness to Consolidated EBITDA, including pro forma adjustments (as defined within the agreement), for the previous four quarter period to exceed 4.0 to 1.0. We were in compliance with the restrictive covenants at December 31, 2001.

364-DAY CREDIT FACILITY. In conjunction with the Multi-Year Credit Agreement, we entered into a 364-day $150 million revolving bank credit facility. In November 2001, we and our lenders amended the revolving credit agreement to extend the maturity date to November 15, 2002 with the option to convert any revolving credit balance outstanding at November 15, 2002 to a one-year term loan.

We can increase the amount borrowed under this facility, with the consent of the Administrative Agent (whose consent may not be unreasonably withheld), up to an amount not exceeding $250 million by adding to the facility one or more new lenders and/or increasing the commitments of existing lenders, so long as the aggregate amount of the funds borrowed under this credit facility and the Multi-Year Credit Facility do not exceed $500 million. No lender will be required to increase its original commitment, unless it agrees to do so at its sole discretion. This credit facility is guaranteed by the MLP through an unsecured guarantee.

Proceeds from this credit facility will be used for working capital, acquisitions and other general partnership purposes. No amount was outstanding for this credit facility at December 31, 2001.

Our obligations under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. As defined within the agreement, borrowings under this bank credit facility will generally bear interest at either (i) the greater of the Prime Rate or the Federal Funds Effective Rate plus one-half percent or (ii) a Eurodollar Rate plus an applicable margin or (iii) a Competitive Bid Rate. We elect the basis for the interest rate at the time of each borrowing.

Limitations on certain actions by the Company and financial condition covenants of this bank credit facility are substantially consistent with those existing for the Multi-Year Credit Facility as described previously. We were in compliance with the restrictive covenants at December 31, 2001.

February 2001 Registration Statement

On February 23, 2001, we filed a $500 million universal shelf registration (the "February 2001 Shelf") covering the issuance of an unspecified amount of equity or debt securities or a combination thereof. We expect to use the net proceeds from any sale of securities for future business acquisitions and other general corporate purposes, such as working capital, investments in subsidiaries, the retirement of existing debt and/or the repurchase of Common Units or other securities. The exact amounts to be used and when the net proceeds will be applied to partnership purposes will depend on a number of factors, including our funding requirements and the availability of alternative funding sources. We routinely review acquisition opportunities.

Increase in fair value of fixed-rate debt

Upon adoption of SFAS No. 133 (see Note 13), we recorded a $2.3 million fair value adjustment associated with our fixed-rate debt. The fair value adjustment is not a cash obligation of the Company and does not alter the amount of our indebtedness. Under the specific rules of SFAS 133, the fair value adjustment will be amortized over the remaining life of the fixed-rate debt to which it is associated, which approximates 10 years. See "Interest Rate Swaps" under Note 13 for additional information concerning this item.

Impact of interest rate swap agreements upon interest expense

During 2001 and 2000, we utilized interest rate swap agreements to manage debt service costs by converting a portion of our fixed-rate debt into variable-rate debt. Income or losses sustained on these financial instruments are reflected as a component of consolidated interest expense. At December 31, 2000, we had three interest rate swaps outstanding having a combined notional value of $154 million (attributable to fixed-rate debt) with an estimated fair value of $2.0 million. Due to the early termination of two of the swaps, the notional amount and fair value of the remaining swap was $54 million and $2.3 million (an asset), respectively, at December 31, 2001.

We recorded as a reduction of interest expense $13.2 million from our interest rates swaps during 2001 and $10.0 million during 2000. The income recognized in 2001 from these swaps includes the $2.3 million in non-cash mark-to-market income at December 31, 2001 (attributable to the sole remaining swap). The remaining $10.9 million has been realized. No mark-to-market income was recorded prior to the implementation of SFAS No. 133. For additional information regarding our interest rate swaps, see Note 13.

7. CAPITAL STRUCTURE

The Second Amended and Restated Agreement of Limited Partnership of the Company (the "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. When quarterly distributions exceed $0.253 per Unit, the General Partner receives a percentage of the excess between the actual distribution rate and the target level ranging from approximately 15% to 50% depending on the target level achieved.

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 (except for Common Units upon conversion of Subordinated Units, pursuant to employee benefit plans, upon conversion of the general partner interest as a result of the withdrawal of the General Partner or in connection with acquisitions or capital improvements that are accretive on a per Unit basis) or an equivalent number of securities ranking on a parity with the Common Units, without the approval of the holders of at least a Unit Majority. 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). After adjusting for the Units issued in connection with the TNGL acquisition, the number of Common Units available (and unreserved) to us for general partnership purposes during the Subordination Period was 54,550,000 at December 31, 2001.

SUBORDINATED UNITS. The 42,819,740 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 the Subordinated Units may undergo an early conversion into Common Units should certain criteria be satisfied. Based upon these criteria, the earliest that the first 25% of the Subordinated Units would convert into Common Units is May 1, 2002. Should the criteria continue to be satisfied through the first quarter of 2003, an additional 25% of the Subordinated Units would undergo an early conversion into Common Units on May 1, 2003. The remaining 50% of Subordinated Units would convert on August 1, 2003 should the balance of the conversion requirements be 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 generally 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 29.0 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 12.0 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 41.0 million Special Units issued, 12.0 million have already converted to Common Units (2.0 million in August 2000 and 10.0 million in August 2001). The remaining Special Units will convert to Common Units on a one for one basis as follows: 19.0 million in August 2002 and 10.0 million in August 2003. These conversions have a dilutive effect on basic earnings per Unit.

Under the rules of the New York Stock Exchange, the conversion of Special Units into Common Units requires the approval of a majority of Common Unitholders. An affiliate of EPCO, which owns in excess of 62% of the outstanding Common Units, has voted its Units in favor of past conversions, which provided the necessary votes for approval.

BUY-BACK PROGRAM. In 2000, the General Partner authorized us to repurchase and retire up to 2,000,000 of our publicly-held Common Units. The repurchase and retirements will be made during periods of temporary market weakness at price levels that would be accretive to our remaining Unitholders.

In September 2001, the General Partner approved a modification to the Buy-Back Program that allows both the Company (specifically, Enterprise Products Partners L.P.) and its consolidated revocable grantor trust (EPOLP 1999 Grantor Trust or the "Trust") to repurchase Common Units under the program. Under the terms of the modification, purchases made by the Company will continue to be retired whereas purchases made by the Trust will remain outstanding and not be retired. The Common Units purchased by the Trust will be accounted for as Treasury Units.

During 2000, the Company repurchased and retired 56,800 Common Units under this program. The Trust purchased 792,800 Common Units under this program in 2001. At December 31, 2001, 1,150,400 Common Units could be repurchased and/or retired under this program. (see Note 16 for a discussion of a subsequent event involving the declaration of a two-for-one split of Common Units that occurred in May 2002).

TREASURY UNITS ACQUIRED BY TRUST. During the first quarter of 1999, the Operating Partnership established the 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 Common Units purchased by the Trust are accounted for in a manner similar to treasury stock under the cost method of accounting. The Trust purchased 534,400 Common Units in 1999 at a cost of $4.7 million and 792,800 Common Units in 2001 at a cost of $18.0 million.

In November 2001, the 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 has been credited to Partners' Equity accounts in a manner similar to additional paid-in capital.

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, 1997.............	67,105,830	42,819,740		
Units issued to public................	24,000,000			
Balance, December 31, 1998.............	91,105,830	42,819,740		
Special Units issued to Shell in connection with TNGL acquisition...			29,000,000	
Treasury Units purchased by consolidated Trust.................	(534,400)			534,400
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 into 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

	LIMITED PARTNERS			
	COMMON UNITS	SUBORDINATED UNITS	SPECIAL UNITS	TREASURY UNITS
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 into 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

8. 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. 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. The following table reconciles the number of Units used in the calculation of basic earnings per Unit and diluted earnings per Unit for each of the three years ended December 31, 2001, 2000 and 1999.

The weighted-average number of Common Units outstanding in 2001 and 2000 reflect the conversion of a portion of Shell's Special Units to Common Units in August of each year. Specifically, ten million Special Units converted to Common Units in August 2001 and two million Special Units converted in August 2000. The weighted-average number of Special Units outstanding in 2001 and 2000 reflect the above conversions and the issuance of six million Special Units in August 2001 and August 2000. See Note 7 for additional information regarding Shell's Special Units.

	FOR YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Income before minority interest...................	$244,650	$222,759	$121,521
General partner interest..........................	(5,608)	(2,597)	(1,203)
Income before minority interest available to Limited Partners................................	239,042	220,162	120,318
Minority interest.................................	(2,472)	(2,253)	(1,226)
Net income available to Limited Partners...........	$236,570	$217,909	$119,092
BASIC EARNINGS PER UNIT NUMERATOR			
Income before minority interest available to Limited Partners..........................	$239,042	$220,162	$120,318

Net income available to Limited Partners	$236,570	$217,909	$119,092
DENOMINATOR (WEIGHTED-AVERAGE)			
Common Units outstanding	96,632	91,396	90,600
Subordinated Units outstanding	42,820	42,820	42,820
Total	139,452	134,216	133,420

	FOR YEAR ENDED DECEMBER 31,		
	2001	2000	1999
BASIC EARNINGS PER UNIT			
Income before minority interest available to Limited Partners	$ 1.72	$ 1.64	$ .90
Net income available to Limited Partners	$ 1.70	$ 1.63	$ .90
DILUTED EARNINGS PER UNIT NUMERATOR			
Income before minority interest available to Limited Partners	$239,042	$220,162	$120,318
Net income available to Limited Partners	$236,570	$217,909	$119,092
DENOMINATOR (WEIGHTED-AVERAGE)			
Common Units outstanding	96,632	91,396	90,600
Subordinated Units outstanding	42,820	42,820	42,820
Special Units outstanding	31,334	30,672	12,156
Total	170,786	164,888	145,576
DILUTED EARNINGS PER UNIT			
Income before minority interest available to Limited Partners	$ 1.40	$ 1.34	$ .83
Net income available to Limited Partners	$ 1.39	$ 1.32	$ .82

9. DISTRIBUTIONS

We intend, to the extent there is sufficient available cash from Operating Surplus, as defined by the Partnership Agreement, to distribute to each holder of Common Units at least a minimum quarterly distribution of $0.225 per Common Unit. The minimum quarterly distribution is not guaranteed and is subject to adjustment as set forth in the Partnership Agreement. 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 quarterly distributions is increased after certain specified target levels are met. We made incentive distributions to the General Partner of $3.2 million during 2001 and $0.4 million during 2000.

The following table is a summary of cash distributions to partnership interests since the first quarter of 1999.

	CASH DISTRIBUTION HISTORY			
	PER COMMON UNIT	PER SUBORDINATED UNIT	RECORD DATE	PAYMENT DATE
1999				
1st Quarter	$0.2250	$0.0350	Apr. 30, 1999	May 12, 1999
2nd Quarter	$0.2250	$0.1850	Jul. 30, 1999	Aug. 11, 1999
3rd Quarter	$0.2250	$0.2250	Oct. 29, 1999	Nov. 10, 1999
4th Quarter	$0.2500	$0.2500	Jan. 31, 2000	Feb. 10, 2000
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

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.

10. RELATED PARTY TRANSACTIONS

We have no employees. All management, administrative and operating functions are performed by employees of EPCO pursuant to the EPCO Agreement (in effect since July 1998). Under the terms of the EPCO Agreement, EPCO agreed to:

- employ the personnel necessary to manage our business and affairs (through the General Partner);

- employ the operating personnel involved our business for which we reimburse EPCO at cost (based upon EPCO's actual salary costs and related fringe benefits);

- 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 use all of the EPCO trademarks and trade names;

- indemnify us against any losses resulting from certain lawsuits; and to

- 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 its' purchase option under such leases to us. EPCO remains liable for the lease payments associated with these assets.

Operating costs and expenses (as shown in the audited Statements of Consolidated Operations) treat the full amount of lease payments being made by EPCO as a non-cash operating expense (with the offset to Partners' Equity on the Consolidated Balance Sheet). In addition, operating costs and expenses include compensation charges for EPCO's employees who operate the facilities.Pursuant to the EPCO Agreement, we reimburse EPCO for our portion of the costs of certain of its employees who manage our business and affairs. In general, our reimbursement of EPCO's expense associated with administrative positions that were active at the time of our initial public offering in July 1998 is capped by the Administrative Services Fee that we pay (currently at $16 million annually). The General Partner, with the approval and consent of the Audit and Conflicts Committee, may agree to annual 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 (including those associated with equity-based awards granted to certain individuals within this group) and the Administrative Services Fee will be retained by EPCO (i.e., EPCO solely bears any shortfall in reimbursement for this group).

Beginning in January 2000, we began reimbursing EPCO for our share of the compensation of administrative personnel that it had hired in response to our expansion and business development activities (through the construction of new facilities, business acquisitions or the like). EPCO began hiring "expansion" administrative personnel during 1999 in connection with the TNGL acquisition and other development activities. In general, we reimburse EPCO for our share of its compensation expense associated with these "expansion" administrative positions, including those costs attributable to equity-based awards.

The following table summarizes the Administrative Services Fee paid to EPCO during the last three years. In addition, the table shows the total compensation reimbursed to EPCO for operations personnel and "expansion" administrative positions.

	FOR YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Administrative Services Fee paid to EPCO..............	$15,125	$13,750	$12,500
Compensation reimbursed to EPCO.......................	48,507	44,717	26,889
Total..	$63,632	$58,467	$39,389

We elected to prepay EPCO a discounted amount of $15.7 million for the 2002 Administrative Services Fee in December 2001 (the undiscounted amount was $16.0 million). We will owe EPCO for any undiscounted amount above the $16.0 million if the General Partner approves an increase in the fee during 2002.

Other related party and similar transactions with EPCO or its affiliates

EPCO also operates the facilities owned by BEF and EPIK and charges them for actual salary costs and related fringe benefits. In addition, EPCO is paid a management fee by these entities in lieu of reimbursement for the actual cost of providing management services; such charges aggregated $0.8 for 2001, $0.9 million for 2000 and $0.8 million in 1999.

We have entered into an agreement with EPCO to provide trucking services related to the loading and transportation of NGL products. EPCO charged us $9.0 million in 2001, $7.9 million in 2000 and $5.7 million in 1999 for these services. On occasion, in the normal course of business, we may engage in transactions with EPCO involving the buying and selling of NGL products. No such sales or purchases were transacted with EPCO during 2001 and 2000; however, we purchased a net $20.6 million of such products from EPCO during 1999.

In addition, trust affiliates of EPCO (Enterprise Products 1998 Unit Option Plan Trust and the Enterprise Products 2000 Rabbi Trust) purchase Common Units for the purpose of granting options to EPCO management and certain key employees (many of whom also serve in similar capacities with the General Partner). During 2001, these trusts purchased 423,036 Common Units on the open market or through privately negotiated transactions. At December 31, 2001, these trusts owned a total of 2,923,036 Common Units. In November 2001, EPCO directly purchased 1,000,000 Common Units at market prices from our consolidated trust, EPOLP 1999 Grantor Trust, on behalf of a key executive.

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.

Relationships with Shell

We have an extensive and ongoing relationship with Shell as a partner, customer and vendor. Shell, through its subsidiary Shell US Gas & Power LLC, owns approximately 23.2% of our limited partnership interests and 30.0% of the General Partner. Currently, three members of the Board of Directors of the General Partner are employees of Shell.

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. Shell is the largest oil and gas producer 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 to process any and all of Shell's Gulf of Mexico natural gas production from existing and future dedicated 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 deliver to Shell the natural gas stream after the mixed NGL stream is extracted.

Apart from operating expenses arising from the Shell Processing Agreement, we also sell NGL and petrochemical products to Shell.

The following table shows the related party amounts by major category in the Company's Statements of Consolidated Operations for the last three years. The table also shows the total amounts paid to EPCO separately under the EPCO Agreement for employee-related costs for the last three years.

	FOR YEAR ENDED DECEMBER 31,		
	2001	2000	1999
REVENUES FROM CONSOLIDATED OPERATIONS			
Unconsolidated affiliates	$173,684	$ 61,988	$ 40,352
Shell	333,333	292,741	56,301
EPCO and subsidiaries	5,439	4,750	9,148
OPERATING COSTS AND EXPENSES			
Unconsolidated affiliates	41,062	58,202	20,696
Shell	705,440	736,655	188,570
EPCO and subsidiaries	10,075	9,492	35,046
EPCO AGREEMENT	63,632	58,467	39,389

11. COMMITMENTS AND CONTINGENCIES

REDELIVERY COMMITMENTS

From time to time, we store NGL, petrochemical and natural gas volumes for third parties under various processing, storage and similar agreements. Under the terms of these agreements, we are generally required to redeliver to the owner volumes on demand. We are insured for any physical loss of such volumes due to catastrophic events. At December 31, 2001, NGL and petrochemical volumes aggregating 320 million gallons were due to be redelivered to their owners along with 887,414 MMBtus 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, 2001 are as follows:

2002	$ 5,115
2003	4,862
2004	4,324
2005	279
2006	181
Thereafter	1,077
Total minimum obligations	$15,838

The operating lease commitments shown above exclude the expense associated with various equipment leases contributed to us by EPCO at our formation for which EPCO has retained the liability. During 2001, 2000 and 1999, our non-cash lease expense associated with these EPCO "retained" leases was $10.4 million, $10.6 million and $10.6 million, respectively.

Lease and rental expense (including Retained Leases) included in operating income for the years ended December 31, 2001, 2000 and 1999 was approximately $23.4 million, $21.2 million and $20.6 million. EPCO has assigned us the purchase options associated with the retained leases. Should we decide to exercise our purchase options under the retained leases, up to $26.0 million will be payable in 2004, $3.4 million in 2008 and $3.1 million in 2016.

PURCHASE COMMITMENTS

Gas purchase commitments. We have long-term purchase commitments for NGL products and related-streams including natural gas with several suppliers. The purchase prices contained within these contracts approximate market value at the time of delivery. The following table shows our long-term volume commitments under these contracts.

	2002	2003	2004	2005	2006	THEREAFTER
NGLs (000s barrels):						
Ethane	2,154	2,154	1,677	1,089	126	
Propane	2,898	2,826	1,899	900	102	
Isobutane	498	498	387	252	30	
Normal Butane	1,134	964	735	303	34	
Natural Gasoline	1,944	1,944	1,488	846	48	
Other	960	460	180			
Total NGLs	9,588	8,846	6,366	3,390	340	
Natural gas (BBtus)	13,726	13,726	12,996	12,996	12,996	75,600

Capital spending commitments. As of December 31, 2001, we had capital expenditure commitments totaling approximately $5.3 million, of which $0.3 million relates to our portion of internal growth projects of unconsolidated affiliates.

LITIGATION

We are indemnified for any litigation pending as of the date of our formation by EPCO. 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 asa result of ordinary business activity. Except as noted below, 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.

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 nine 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, 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 necessitate 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 have been challenged under state law in litigation filed on January 19, 2001, against the Texas Natural Resource Conservation Commission and its principal officials in the District Court of Travis County, Texas, by a coalition of major Houston-Galveston area industries, including us. Until this litigation is resolved, the precise level of technology to be employed and the cost for modifying the facilities to achieve the required amount of reductions cannot be determined. Currently, the litigation has been stayed by agreement of the parties pending the outcome of expanded, cooperative scientific research to more precisely define sources and mechanisms of air pollution in the Houston-Galveston area. Completion of this research is anticipated in mid-2002.

12. SUPPLEMENTAL CASH FLOWS DISCLOSURE

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

	FOR YEAR ENDED DECEMBER 31,		
	2001	2000	1999
(Increase) decrease in:			
Accounts receivable	$ 230,629	$(93,716)	$(152,363)
Inventories	30,862	(21,452)	7,471
Prepaid and other current assets	(25,524)	2,352	(7,523)
Intangible assets		(5,226)	
Other assets	162	(1,410)	1,164
Increase (decrease) in:			
Accounts payable	(82,075)	18,723	(6,276)
Accrued gas payable	(197,916)	143,457	206,178
Accrued expenses	(1,576)	4,978	(27,788)
Accrued interest	14,234	8,743	863
Other current liabilities	3,073	6,540	5,884
Other liabilities	(9,012)	8,122	296
Net effect of changes in operating accounts	$ (37,143)	$ 71,111	$ 27,906
Cash payments for interest, net of $2,946, $3,277 and $153 capitalized in 2001, 2000 and 1999, respectively	$ 37,536	$ 17,774	$ 15,780

On April 1, 2001, we paid approximately $225.7 million in cash to Shell to acquire Acadian Gas. This acquisition was recorded using the purchase method of accounting and as a result the initial purchase price has been allocated to various balance sheet asset and liability accounts. For additional information regarding the acquisition of Acadian Gas (including the allocation of the purchase price), see Note 2.

On August 1, 1999, we paid $166 million in cash and issued 29.0 million non-distribution bearing, convertible Special Units (valued at $210.4 million at time of issuance) to Shell in connection with the TNGL acquisition. Also, we issued 12.0 million additional non-distribution bearing, convertible Special Units to Shell based on Shell having met certain performance criteria in calendar years 2000 and 2001. Of the 12.0 million additional Special Units issued, 6.0 million were issued in 2000 and 6.0 million during 2001. The value of the Special Units issued in 2000 was $55.2 million while the value of those issued during 2001 was $117.1 million, both values determined using present value techniques. The $172.3 million combined value of these two issues increased the overall purchase price of the TNGL acquisition and was allocated to the intangible asset, Shell Processing Agreement. In addition, during 2000, we increased the value of the Shell Processing Agreement by $25.2 million for non-cash purchase accounting adjustments related to the acquisition. The offset to such adjustment was various working capital accounts. With these adjustments completed, the final purchase price of TNGL increased to $528.8 million.

On July 1, 1999, we paid approximately $42.1 million in cash to EPCO and Kinder Morgan and assumed approximately $4 million of debt in connection with the acquisition of an additional interest in the Mont Belvieu NGL fractionation facility.

As a result of our adoption of SFAS No. 133 on January 1, 2001, we record various financial instruments relating to commodity positions and interest rate swaps at their respective fair values using mark-to-market accounting. During 2001, we recognized a net $5.7 million in non-cash mark-to-market income related to increases in the fair value of these financial instruments. See Note 13 for additional information on our financial instruments.

13. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices in our natural gas and NGL businesses and in interest rates with respect to a portion of our debt obligations. 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 in its Processing segment. In general, the types of risks hedged 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.

Our disclosure of fair value estimates are determined using available market information and appropriate valuation methodologies. We must use considerable judgment, however, in interpreting market data and to develop the related estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize upon disposition of the financial instruments. The use of different market assumptions and/or estimation methodologies may have a material effect on our estimates of fair value.

COMMODITY FINANCIAL INSTRUMENTS

Our Processing and Octane Enhancement segments are directly exposed to commodity price risk through their respective business operations. The prices of natural gas, NGLs 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 its Processing segment, we may enter into swaps, forwards, commodity futures, options and other commodity financial instruments with similar characteristics that are permitted by contract or business custom to be settled in cash or with another financial instrument. The primary purpose of these risk management activities is to hedge exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions. We do not hedge our exposure to the MTBE markets. Also, in its Pipelines segment, we may utilize a limited number of commodity financial instruments to manage the price Acadian Gas charges certain of its customers for natural gas.

We have adopted a commercial policy to manage our exposure to the risks of its 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 its commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 18 months. The General Partner oversees the 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.

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.

At December 31, 2001, we had open commodity financial instruments that settle at different dates extending through December 2002. We routinely review our outstanding 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 economic hedge to which the closed instrument relates.

These commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133 because of ineffectiveness. A hedge is normally regarded as effective if, among other things, at inception and throughout the term of the financial instrument, we could expect changes in the fair value of the hedged item to be almost fully offset by the changes in the fair value of the financial instrument. Currently, a majority of our commodity financial instruments do not qualify as effective hedges under the guidelines of SFAS No. 133, with the result being that changes in the fair value of these positions are recorded on the balance sheet and in earnings through mark-to-market accounting. The use of mark-to-market accounting for these commodity financial instruments results in a degree of non-cash earnings volatility that is dependent upon changes in the underlying commodity prices. Even though these financial instruments do not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133, we continue to view these financial instruments as hedges inasmuch as this was the intent when such contracts were executed. This characterization is consistent with the actual economic performance of these contracts to date and we expect these financial instruments to continue to mitigate (or offset) commodity price risk in future. The specific accounting for these contracts, however, is consistent with the requirements of SFAS No. 133.

We recognized income of $101.3 million in 2001 from our commodity hedging activities that is treated as a decrease of operating costs and expenses in the Statements of Consolidated Operations. Of this amount, $95.7 million was realized during 2001. The remaining $5.6 million represents mark-to-market income on positions open at December 31, 2001 (based on market prices at that date).

INTEREST RATE SWAPS

Our interest rate exposure results from variable-rate borrowings from commercial banks and fixed-rate borrowings pursuant to its Senior Notes and MBFC Loan. We manage its exposure to changes in interest rates by utilizing interest rate swaps. The objective of holding 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. An interest rate swap, in general, requires one party to pay a fixed-rate on the notional amount while the other party pays a floating-rate based on the notional amount. We believe that it is prudent to maintain an appropriate mixture of variable-rate and fixed-rate debt.

We assess interest rate cash flow risk by identifying and measuring changes in interest rate exposure that impact future cash flows and evaluating hedging opportunities. We use analytical techniques to measure its 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 financial risks and approves instruments that are appropriate for our requirements. The notional amount of an interest rate swap 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 is remote, and that if incurred, such losses would be immaterial.

At December 31, 2001, we had one interest rate swap outstanding having a notional amount of $54 million extending through March 2010. Under this agreement, we exchanged a fixed-rate of 8.70% for a variable-rate that ranged from 4.28% to 7.66% during 2001 (the variable-rate may fluctuate over time depending on market conditions). If it elects to do so, the counterparty may terminate this swap in March

2003. During 2001, two counterparties terminated their swap agreements with us either through early termination clauses or negotiation. The closed agreements had a combined notional amount of $100 million.

Upon adoption of SFAS No. 133, we were required to recognize the fair value of the interest rate swaps on the balance sheet offset by an equal increase in the fair value of associated fixed-rate debt and, therefore, the adoption of the new standard had no impact on earnings at transition. Subsequently, it was determined that the interest rate swaps would not qualify for hedge accounting treatment under SFAS No. 133 due to differences between the maturity dates of the swaps and the associated fixed-rate debt; thus, changes in the fair value of the interest rate swaps would be recorded in earnings through mark-to-market accounting (i.e., the interest rate swaps were deemed ineffective under SFAS No. 133). As a result, the increase in fair value of the associated fixed-rate debt will not be adjusted for future changes in its fair value and will be amortized to earnings over the remaining life of the underlying debt instrument, which approximates 10 years.

We recognized income of $13.2 million in 2001 from our interest rate swaps that is treated as a reduction of interest expense in the Statements of Consolidated Operations. Of this amount, $2.3 million represents the mark-to-market income on the remaining swap at December 31, 2001 (estimated fair value of swap based on market rates at that date). The balance of $10.9 million was realized during 2001.

The $2.3 million estimated fair value of the remaining swap at December 31, 2001 is based on market rates (assuming its early termination option in March 2003 is exercised). The fair value estimate represents the amount that we would receive to terminate the swap, taking into consideration current interest rates.

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.

OTHER 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.

Fixed-rate long term debt. The estimated fair value of our fixed-rate long-term debt is estimated based on quoted market prices for debt of similar terms and maturities. No variable rate long-term debt was outstanding at December 31, 2001.

The following table summarizes the estimated fair values of our various financial instruments at December 31, 2001 and 2000:

	2001		2000	
FINANCIAL INSTRUMENTS	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
Financial assets:				
Cash and cash equivalents	$137,823	$137,823	$ 60,409	$ 60,409
Accounts receivable(1)	261,302	261,302	415,618	415,618
Commodity financial instruments(2)	9,992	9,992	n/a	n/a
Interest rate swaps(3)	2,324	2,324	n/a	n/a
Financial liabilities:				
Accounts payable and accrued expenses	364,452	364,452	561,688	561,688
Fixed-rate debt (principal amount)	854,000	894,005	404,000	423,836
Commodity financial instruments(4)	3,206	3,206	725	705
Off-balance sheet instruments:(5)				
Interest rate swaps receivable	n/a	n/a	2,030	2,030
Commodity financial instruments payable	n/a	n/a	40,020	39,266

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(1) 2001 includes a $1.2 million receivable related to the remaining interest rate swap.

(2) 2001 values are a component of other current assets in our consolidated balance sheet.

(3) 2001 value represents the aggregate fair value of the remaining swap (net of the $1.2 million receivable reflected under accounts receivable). $1.3 million of the $2.3 million mark-to-market value is a component of other current assets while the balance of $1.0 million is reflected in other assets.

(4) 2001 values are a component of other current liabilities in our consolidated balance sheet.

(5) Prior to our adoption of SFAS No. 133 on January 1, 2001, interest rate swaps and certain commodity financial instruments were off-balance sheet instruments. As a result of SFAS No. 133, these financial instruments are now recorded as part of balance sheet assets and liabilities, as the circumstances warrant.

14. 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. Although this concentration could affect our overall exposure to credit risk since these customers might be affected by similar economic or other conditions, management believes we are exposed to minimal credit risk, since the majority of our business is conducted with major companies within the industry including those with whom it has joint operations. We do not require collateral for our accounts receivable.

NATURE OF OPERATIONS. We are subject to a number of risks inherent in the industry in which it operates, including fluctuating gas and liquids prices. Our financial condition and results of operation will depend significantly on the prices received for NGLs and the price paid for gas consumed in the NGL extraction process. These 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 its processing business in order to maintain or increase gas plant throughput 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 NGL 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.

COUNTERPARTY RISK. From time to time, we have credit risk with our counterparties in terms of settlement risk associated with its financial instruments. On all transactions where we are exposed to credit risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis.

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 $10.6 million reserve for amounts owed to us by Enron North America, a subsidiary of Enron. Enron North America was our counterparty to various past financial instruments. The Enron amounts were unsecured and the amount that we may ultimately recover, if any, is not presently determinable. Of the reserve amount established, $4.3 million was attributable to various unbilled commodity financial instrument positions that terminate during the first quarter of 2002.

15. SEGMENT INFORMATION

Operating segments are components of a business about which separate financial information is available and that 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: Fractionation, Pipelines, 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. Fractionation primarily includes NGL fractionation, isomerization, and polymer grade propylene fractionation services. Pipelines consists of both liquids and natural gas pipeline systems, storage and import/export terminal services. Processing includes the natural gas processing business and its related merchant 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 other plant support functions.

We evaluate segment performance based on 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 interest expense, interest income (from unconsolidated affiliates or others), dividend income from unconsolidated affiliates, minority interest, extraordinary charges and other income and expense transactions.

We include equity earnings from unconsolidated affiliates in segment gross operating margin and as a component of revenues. 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 these businesses 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 merchant businesses. 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.

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.

Segment gross operating margin is inclusive of intersegment revenues, which are generally based on transactions made at market-related rates. These revenues have been eliminated from the consolidated totals.

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

	OPERATING SEGMENTS					ADJS. AND	CONSOL.
	FRACTIONATION	PIPELINES	PROCESSING	OCTANE ENHANCEMENT	OTHER	ELIMS.	TOTALS
Revenues from external customers:							
2001....................	$324,276	$403,430	$2,424,281		$2,382		$3,154,369
2000....................	396,995	28,172	2,620,975		2,878		3,049,020
1999....................	247,579	11,498	1,073,171		731		1,332,979
Intersegment revenues:							
2001....................	158,853	89,907	683,524		389	$(932,673)	
2000....................	177,963	55,690	630,155		375	(864,183)	
1999....................	118,103	43,688	216,720		444	(378,955)	
Equity income in unconsolidated affiliates:							
2001....................	6,945	12,742		$ 5,671			25,358
2000....................	6,391	7,321		10,407			24,119
1999....................	1,566	3,728		8,183			13,477
Total revenues:							
2001....................	490,074	506,079	3,107,805	5,671	2,771	(932,673)	3,179,727
2000....................	581,349	91,183	3,251,130	10,407	3,253	(864,183)	3,073,139
1999....................	367,248	58,914	1,289,891	8,183	1,175	(378,955)	1,346,456
Gross operating margin by segment:							
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
1999....................	110,424	31,195	28,485	8,183	908		179,195
Segment assets:							
2001....................							

357,122 717,348 124,555
8,921 98,844 1,306,790
2000....................
356,207 448,920 126,895
8,942 34,358 975,322
1999....................
362,198 249,453 122,495
113 32,810 767,069
Investments in and
advances to
unconsolidated
affiliates:
2001....................
93,329 216,029 33,000
55,843 398,201
2000....................
105,194 102,083 33,000
58,677 298,954
1999....................
99,110 85,492 33,000
63,004 280,606

Our revenues are derived from a wide customer base. Shell accounted for 10.5% of consolidated revenues in 2001 (up from 9.5% of consolidated revenues in 2000). No single external customer accounted for more than 10% of consolidated revenues during 2000 and 1999. Approximately 80% of our revenues from Shell during 2001 and 2000 are attributable to sales of NGL products which are recorded in our Processing segment. No single third-party customer provided more than 10% of consolidated revenues during 2000 or 1999. All consolidated revenues were earned in the United States. Our operations are centered along the Texas, Louisiana and Mississippi Gulf Coast areas.

A reconciliation of segment gross operating margin to consolidated income before minority interest follows:

	FOR YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Total segment gross operating margin	$376,783	$320,615	$179,195
Depreciation and amortization	(48,775)	(35,621)	(23,664)
Retained lease expense, net	(10,414)	(10,645)	(10,557)
(Gain) loss on sale of assets	390	(2,270)	(123)
Selling, general and administrative	(30,296)	(28,345)	(12,500)
Consolidated operating income	287,688	243,734	132,351
Interest expense	(52,456)	(33,329)	(16,439)
Interest income from unconsolidated affiliates	31	1,787	1,667
Dividend income from unconsolidated affiliates	3,462	7,091	3,435
Interest income -- other	7,029	3,748	886
Other, net	(1,104)	(272)	(379)
Consolidated income before minority interest	$244,650	$222,759	$121,521

16. SUBSEQUENT EVENTS (UNAUDITED)

PURCHASE OF DIAMOND-KOCH STORAGE ASSETS. On January 17, 2002, we completed the purchase of various hydrocarbon storage assets from affiliates of Valero Energy Corporation and Koch Industries, Inc. The purchase price of the storage assets was approximately $129 million (subject to certain post-closing adjustments) and will be accounted for as an asset purchase. The purchase price was funded entirely by internally generated funds.

The storage facilities include 30 salt dome storage caverns with a total useable capacity of 68 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.

PURCHASE OF DIAMOND-KOCH PROPYLENE FRACTIONATION ASSETS. On February 1, 2002, we completed the purchase of various propylene fractionation assets from affiliates of Valero Energy Corporation and Koch Industries, Inc. and certain inventories of refinery grade propylene, propane and polymer grade propylene owned by such affiliates. The purchase price of these assets was approximately $238.5 million (subject to certain post-closing adjustments) and will be accounted for as an asset purchase. The purchase price was funded by a drawdown on our existing revolving bank credit facilities.

The propylene fractionation assets being acquired include a 66.67% interest in a polymer grade propylene fractionation facility located in Mont Belvieu, Texas, a 50.0% 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. The propylene fractionation facility has the gross capacity to produce approximately 41,000 barrels per day of polymer grade propylene.

Both the storage and propylene fractionation acquisitions have been approved by the requisite regulatory authorities. The post-closing purchase price adjustments of both transactions are expected to be completed during the second quarter of 2002.

TWO-FOR-ONE SPLIT OF LIMITED PARTNER UNITS. On February 27, 2002, the General Partner approved a two-for-one split for each class of our 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 30, 2002. The Units were distributed on May 15, 2002. All references to number of Units or earnings per Unit contained in this document reflect the Unit split, unless otherwise indicated.

17. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
FOR THE YEAR ENDED DECEMBER 31, 2000:				
Revenues	$753,724	$604,010	$721,863	$993,542
Operating income	75,434	50,046	55,864	62,390
Income before minority interest	70,156	46,026	50,777	55,800
Minority interest	(709)	(466)	(514)	(564)
Net income	69,447	45,560	50,263	55,236
Net income per Unit, basic	$ 0.52	$ 0.34	$ 0.37	$ 0.41
Net income per Unit, diluted	$ 0.43	$ 0.28	$ 0.30	$ 0.33
FOR THE YEAR ENDED DECEMBER 31, 2001:				
Revenues	$838,326	$968,447	$729,618	$643,336
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	$ 0.31	$ 0.55	$ 0.43	$ 0.12

Earnings in the fourth quarter of 2001 declined relative to the third quarter of 2001 primarily due to a decrease in the mark-to-market value of our commodity financial instruments. The decrease was due to (1) the settlement of certain positions during the fourth quarter, (2) a decrease in the relative amount of hedging activities at December 31, 2001 versus September 30, 2001 and (3) a decrease in the value of certain outstanding financial instruments from September 30, 2001 due to changes in natural gas prices.

ENTERPRISE PRODUCTS PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS
(DOLLARS IN THOUSANDS)

	JUNE 30, 2002 (UNAUDITED)	DECEMBER 31, 2001
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents (includes restricted cash of $5,034 at June 30, 2002 and $5,752 at December 31, 2001)	$ 7,929	$ 137,823
Accounts and notes receivable -- trade, net of allowance for doubtful accounts of $21,098 at June 30, 2002 and $20,642 at December 31, 2001	284,021	256,927
Accounts receivable -- affiliates	1,740	4,375
Inventories	153,280	69,443
Prepaid and other current assets	34,089	50,207
Total current assets	481,059	518,775
PROPERTY, PLANT AND EQUIPMENT, NET	1,570,571	1,306,790
INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES	403,070	398,201
INTANGIBLE ASSETS, NET OF ACCUMULATED AMORTIZATION OF $18,235 AT JUNE 30, 2002 AND $13,084 AT DECEMBER 31, 2001	249,222	202,226
GOODWILL	81,543	
OTHER ASSETS	6,911	5,201
TOTAL	$2,792,376	$2,431,193
LIABILITIES AND PARTNERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable -- trade	$ 70,716	$ 54,269
Accounts payable -- affiliates	21,233	29,885
Accrued gas payables	303,983	233,536
Accrued expenses	12,961	22,460
Accrued interest	24,676	24,302
Other current liabilities	70,672	44,764
Total current liabilities	504,241	409,216
LONG-TERM DEBT	1,223,552	855,278
OTHER LONG-TERM LIABILITIES	7,919	8,061
MINORITY INTEREST	10,818	11,716
COMMITMENTS AND CONTINGENCIES		
PARTNERS' EQUITY		
Common Units (112,954,266 Units outstanding at June 30, 2002 and 102,721,830 at December 31, 2001)	589,504	651,872
Subordinated Units (32,114,804 Units outstanding at June 30, 2002 and 42,819,740 December 31, 2001)	165,818	193,107
Special Units (29,000,000 Units outstanding at June 30, 2002 and December 31, 2001)	296,634	296,634
Treasury Units, at cost (799,700 Common Units outstanding at June 30, 2002 and 327,200 at December 31, 2001)	(16,736)	(6,222)
General Partner	10,626	11,531
Total Partners' Equity	1,045,846	1,146,922
TOTAL	$2,792,376	$2,431,193

See Notes to Unaudited Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

STATEMENTS OF CONSOLIDATED OPERATIONS
(DOLLARS IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2002	2001	2002	2001
REVENUES				
Revenues from consolidated operations	$786,257	$959,397	$1,448,311	$1,795,712
Equity income in unconsolidated affiliates	7,068	9,050	16,295	11,061
Total	793,325	968,447	1,464,606	1,806,773
COST AND EXPENSES				
Operating costs and expenses	745,621	851,639	1,410,044	1,629,380
Selling, general and administrative	7,740	7,737	15,702	13,905
Total	753,361	859,376	1,425,746	1,643,285
OPERATING INCOME	39,964	109,071	38,860	163,488
OTHER INCOME (EXPENSE)				
Interest expense	(19,032)	(16,331)	(37,545)	(23,318)
Interest income from unconsolidated affiliates	62	7	92	31
Dividend income from unconsolidated affiliates	1,242	--	2,196	1,632
Interest income -- other	241	1,479	1,575	5,477
Other, net	46	(251)	(31)	(531)
Other income (expense)	(17,441)	(15,096)	(33,713)	(16,709)
INCOME BEFORE MINORITY INTEREST	22,523	93,975	5,147	146,779
MINORITY INTEREST	(203)	(944)	(30)	(1,478)
NET INCOME	$ 22,320	$ 93,031	$ 5,117	$ 145,301
ALLOCATION OF NET INCOME TO:				
Limited partners	$ 19,672	$ 91,643	$ 1,223	$ 142,931
General partner	$ 2,648	$ 1,388	$ 3,894	$ 2,370
BASIC EARNINGS PER UNIT				
Income before minority interest	$ 0.14	$ 0.68	$ 0.01	$ 1.07
Net income per Common and Subordinated unit	$ 0.14	$ 0.68	$ 0.01	$ 1.06
DILUTED EARNINGS PER UNIT				
Income before minority interest	$ 0.11	$ 0.55	$ 0.01	$ 0.86
Net income per Common, Subordinated and Special unit	$ 0.11	$ 0.54	$ 0.01	$ 0.85

See Notes to Unaudited Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

STATEMENTS OF CONSOLIDATED CASH FLOWS
(DOLLARS IN THOUSANDS)
(UNAUDITED)

SIX MONTHS ENDED JUNE 30,	2002	2001
OPERATING ACTIVITIES		
Net income	$ 5,117	$ 145,301
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:		
Depreciation and amortization	35,349	23,234
Equity in income of unconsolidated affiliates	(16,295)	(11,061)
Distributions received from unconsolidated affiliates	29,113	13,212
Leases paid by EPCO	4,534	5,267
Minority interest	30	1,478
Loss (gain) on sale of assets	12	(387)
Changes in fair market value of financial instruments (see Note 13)	19,702	(55,880)
Net effect of changes in operating accounts	(32,379)	(30,569)
Operating activities cash flows	45,183	90,595
INVESTING ACTIVITIES		
Capital expenditures	(26,755)	(57,090)
Proceeds from sale of assets	12	563
Business acquisitions, net of cash received	(394,775)	(225,665)
Investments in and advances to unconsolidated affiliates	(10,137)	(115,282)
Investing activities cash flows	(431,655)	(397,474)
FINANCING ACTIVITIES		
Long-term debt borrowings	538,000	449,716
Long-term debt repayments	(170,000)	
Debt issuance costs	(418)	(3,125)
Cash dividends paid to partners	(99,010)	(76,112)
Cash dividends paid to minority interest by Operating Partnership	(1,014)	(783)
Cash contributions from EPCO to minority interest	86	53
Treasury Units purchased	(11,066)	
Increase in restricted cash	718	(7,321)
Financing activities cash flows	257,296	362,428
NET CHANGE IN CASH AND CASH EQUIVALENTS	(129,176)	55,549
CASH AND CASH EQUIVALENTS, JANUARY 1	132,071	60,409
CASH AND CASH EQUIVALENTS, JUNE 30	$ 2,895	$ 115,958

See Notes to Unaudited Consolidated Financial Statements

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL

In the opinion of Enterprise Products Partners L.P., the accompanying unaudited consolidated financial statements include all adjustments consisting of normal recurring accruals necessary for a fair presentation of its consolidated financial position as of June 30, 2002 and consolidated results of operations and cash flows for the three and six months ended June 30, 2002 and 2001. Within these footnote disclosures of Enterprise Products Partners L.P., references to "we", "us", "our" or "the Company" shall mean the consolidated financial statements of Enterprise Products Partners L.P.

References to "Operating Partnership" shall mean the consolidated financial statements of our primary operating subsidiary, Enterprise Products Operating L.P., which are included elsewhere in this combined report on Form 10-Q. We own 98.9899% of the Operating Partnership and act as guarantor of certain debt obligations of the Operating Partnership. Our General Partner, Enterprise Products GP, LLC, owns the remaining 1.0101% of the Operating Partnership. Essentially all of our assets, liabilities, revenues and expenses are recorded at the Operating Partnership level in our consolidated financial statements.

Although we believe the disclosures in these financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to the rules and regulations of the SEC. These unaudited financial statements should be read in conjunction with our annual report on Form 10-K (File No. 1-14323) for the year ended December 31, 2001.

The results of operations for the three and six months ended June 30, 2002 are not necessarily indicative of the results to be expected for the full year.

Dollar amounts presented within these footnote disclosures are stated in thousands of dollars, unless otherwise indicated.

Certain abbreviated entity names and other capitalized terms are described within the glossary of this quarterly report on Form 10-Q.

TWO-FOR-ONE SPLIT OF LIMITED PARTNER UNITS

On February 27, 2002, the General Partner approved a two-for-one split for each class of our 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 30, 2002. The Units were distributed on May 15, 2002. All references to number of Units or earnings per Unit contained in this document reflect the Unit split, unless otherwise indicated.

2. BUSINESS ACQUISITIONS

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 "Mont Belvieu 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. Mont Belvieu 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 Credit Facilities (see Note 8).

ACQUISITION OF DIAMOND-KOCH STORAGE BUSINESS IN JANUARY 2002

In January 2002, we purchased various hydrocarbon storage assets from Diamond-Koch. The storage facilities consist of 30 salt dome storage caverns with a useable capacity of 68 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. Collectively, these facilities represent the largest underground storage operation of its kind in the world. The size and location of the business provide it with a competitive position to increase its services to expanding Gulf Coast petrochemical complexes. 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.

ALLOCATION OF PURCHASE PRICE OF DIAMOND-KOCH ACQUISITIONS

The Diamond-Koch acquisitions were accounted for under the purchase method of accounting and, accordingly, the purchase price of each has been allocated to the assets acquired and liabilities assumed based on their estimated fair values as follows:

	ESTIMATED FAIR VALUES AT		
	FEB. 1, 2002 PROPYLENE FRACTIONATION	JAN. 1, 2002 STORAGE	TOTAL
Inventories	$ 4,994		$ 4,994
Prepaid and other current assets	3,148	$ 890	4,038
Property, plant and equipment	96,772	120,571	217,343
Investments in unconsolidated affiliates	7,550		7,550
Intangible assets (see Note 7)	53,000	8,127	61,127
Goodwill (see Note 7)	73,686		73,686
Current liabilities	(107)		(107)
Total purchase price	$239,043	$129,588	$368,631

The fair value estimates were developed by independent appraisers using recognized business valuation techniques. The allocation of the purchase price is preliminary pending the results of a repermitting process expected to be complete during the fourth quarter of 2002.

The purchase price paid for the propylene fractionation business resulted in $73.7 million in goodwill. 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 2003 and 2004 projected to be peak years in the petrochemical business cycle. Additionally, the demand for chemical grade and polymer grade propylene is forecast to grow at an average of 4.4% per year from 2002 to 2006.

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.

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, of which the majority were related to natural gas inventories. The Acadian Gas acquisition was accounted for under the purchase method of accounting and, accordingly, the final purchase price has been allocated to the assets acquired and liabilities assumed based on their estimated fair values at April 1, 2001 as follows:

Current assets	$ 83,123
Investments in unconsolidated affiliates	2,723
Property, plant and equipment	232,187
Current liabilities	(72,896)
Other long-term liabilities	(1,460)
Total purchase price	$243,677

PRO FORMA EFFECT OF DIAMOND-KOCH AND ACADIAN GAS BUSINESS ACQUISITIONS

As noted earlier, the Acadian Gas acquisition occurred on April 1, 2001. We acquired Diamond-Koch's storage business on January 1, 2002 and its propylene fractionation business on February 1, 2002. As a result, our actual fiscal 2002, Statements of Consolidated Operations reflect the Diamond-Koch propylene fractionation business and the Diamond-Koch storage business from their respective acquisition dates through June 2002 and the results of Acadian Gas. For the first six months of fiscal 2001, our Statements of Consolidated Operations reflect only three months of Acadian Gas.

The following table presents unaudited pro forma financial information incorporating the historical (pre-acquisition) financial results of the propylene fractionation and storage assets we acquired from Diamond-Koch and those of Acadian Gas that we acquired from Shell. This information is helpful in gauging the possible impact that these acquisitions might have had on our results of operations had they been completed on January 1, 2001 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 and, as a result, are 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.

	THREE MONTHS ENDED JUNE 30, 2001	SIX MONTHS ENDED JUNE 30, 2002	SIX MONTHS ENDED JUNE 30, 2001
Revenues	$1,043,671	$1,482,040	$2,195,472
Income before extraordinary item and minority interest	$ 90,424	$ 5,085	$ 147,174
Net income	$ 89,517	$ 5,055	$ 145,692
Allocation of net income to Limited partners	$ 88,128	$ 1,161	$ 143,322
General Partner	$ 1,389	$ 3,894	$ 2,370
Units used in earnings per Unit calculations			
Basic	135,334	145,404	135,334
Diluted	168,334	174,404	168,334
Income per Unit before minority interest			
Basic	$ 0.66	$ 0.01	$ 1.07
Diluted	$ 0.53	$ 0.01	$ 0.86
Net income per Unit			
Basic	$ 0.65	$ 0.01	$ 1.06
Diluted	$ 0.52	$ 0.01	$ 0.85

MINOR ACQUISITIONS INITIATED DURING THE SECOND QUARTER OF 2002

We initiated the purchase of an additional interest in our Mont Belvieu NGL fractionation from ChevronTexaco and the acquisition of a gas processing plant and NGL fractionator in Louisiana from Western Resources during the second quarter of 2002. Due to the immaterial nature and incomplete status of these two transactions, our discussion of each minor purchase is limited to the following:

Acquisition of ChevronTexaco's interest in our Mont Belvieu NGL fractionator. In April 2002, we executed an agreement with an affiliate of ChevronTexaco to purchase their 12.5% undivided ownership interest in our Mont Belvieu, Texas NGL fractionator. The purchase price was approximately $8.0 million. The Mont Belvieu facility has a gross NGL fractionation capacity of 210 MBPD of which 26.2 MBPD was ChevronTexaco's net share. ChevronTexaco was required to sell their 12.5% interest in a consent order by the FTC as a condition of approving the merger between Chevron and Texaco. The effective date of the purchase was June 1, 2002.

The other joint owners of the facility (affiliates of Duke Energy Field Services and Burlington Resources Inc.) have the option to acquire their pro rata share of the ChevronTexaco interest. These preferential purchase rights expire on September 30, 2002. If the other joint owners fully exercise their option to acquire their share of the interest, our ownership interest would increase to approximately 71.4% from 62.5% currently. Should the joint owners decline to exercise their options, we would own 75.0% of the facility. If the other joint owners acquire any portion of their share of the ChevronTexaco interest, our purchase price will be reduced accordingly. We expect to complete this transaction during the third quarter of 2002.

Acquisition of gas processing and NGL fractionator assets from Western Gas Resources, Inc. In June 2002, we executed an agreement to acquire a natural gas processing plant, NGL fractionator and supporting assets (including contracts) from Western Gas Resources, Inc. for $32.5 million plus certain post-closing purchase price adjustments. The "Toca-Western" facilities are located in St. Bernard Parish, Louisiana near our existing Toca natural gas processing plant. The gas processing facility has a capacity of 160 MMcf/d and the NGL fractionator can fractionate up to 14.2 MBPD of NGLs.

This purchase is subject to a preferential purchase right by the other joint owners of our Yscloskey gas processing facility that expires on September 24, 2002. We are one of the largest owners in the Yscloskey plant with a 28.2% ownership interest. Should any of the other owners exercise their respective right to acquire their pro rata interest in the Toca-Western facilities, it would reduce the ownership interest we ultimately acquire and the purchase price we pay. Because of the preferential rights, we expect to close this transaction during the third quarter of 2002.

3. INVENTORIES

Our inventories are as follows at the dates indicated:

	JUNE 30, 2002	DECEMBER 31, 2001
Regular trade inventory	$ 70,340	$35,894
Forward-sales inventory	45,960	33,549
Peak Season inventory	20,959	--
Other	16,021	--
Inventory	$153,280	$69,443

A description of each inventory is as follows:

- Our regular trade (or "working") inventory is comprised of inventories of natural gas, NGLs and petrochemicals that are available for immediate sale. This inventory is valued at the lower of average cost or market, with "market" being determined by spot-market related prices.

- 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 of the sales prices of the forward sales contracts.

- The peak season inventory is comprised of segregated NGL volumes that are expected to be sold outside of the current summer-winter season and is valued at the lower of average cost or market, with "market" being determined by spot-market related prices. These volumes are generally expected to be sold within the next twelve months, but may be held for longer periods depending on market conditions.

- Other inventories generally consist of segregated NGL volumes set aside for possible short-term use as fuel on an equivalent MMBtu basis. This inventory is carried at the lower of average cost or market, with "market" being determined by spot-market related prices. The volumes associated with this inventory are anticipated to be used and/or sold within the next twelve months.

Due to fluctuating market conditions in the NGL, natural gas and petrochemical industry, we occasionally recognize lower of average cost or market 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 affect our segment operating results in the following manner:

- NGL inventory write downs are recorded as a cost of the Processing segment's merchant 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 second quarter of 2002, we recognized an adjustment of $4.5 million to write down NGL inventories to their net realizable value. For the second quarter of 2001, we recorded $25.8 million of such write downs: $19.4 million against NGL inventories, $4.9 million against natural gas inventories and $1.5 million against petrochemical inventories.

For the first six months of 2002, we recognized $4.6 million in NGL inventory write downs. For the same six month period in 2001, we recorded $27.8 million in lower of average cost or market write downs. The 2001 adjustments were $21.4 million against NGL inventories, $4.9 million against natural gas inventories and $1.5 million against petrochemical inventories. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory value adjustments are mitigated (or in some cases, reversed). See Note 13 for a description of our commodity hedging activities.

4. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment and accumulated depreciation are as follows at the dates indicated:

	ESTIMATED USEFUL LIFE IN YEARS	JUNE 30, 2002	DECEMBER 31, 2001
Plants and pipelines	5-35	$1,626,739	$1,398,843
Underground and other storage facilities	5-35	241,806	127,900
Transportation equipment	3-35	3,952	3,736
Land		20,014	15,517
Construction in progress		44,003	98,844
Total		1,936,514	1,644,840
Less accumulated depreciation		365,943	338,050
Property, plant and equipment, net		$1,570,571	$1,306,790

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, and 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.

Depreciation expense for the three months ended June 30, 2002 and 2001 was $13.8 million and $11.0 million, respectively. For the six months ended June 30, 2002 and 2001, it was $27.9 million and $20.3 million, respectively.

5. 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 the operating segment to which they relate. For a general discussion of our operating segments, see Note 14.

We acquired three equity method unconsolidated affiliates as part of our acquisition of Diamond-Koch's propylene fractionation business (see Note 2). We purchased an aggregate 50% interest in La Porte Pipeline Company, L.P. and La Porte Pipeline GP, L.L.C. (collectively, "La Porte") which together own a private polymer grade propylene pipeline extending from Mont Belvieu to La Porte, Texas. In addition, we acquired 50% of the outstanding capital stock of Olefins Terminal Corporation ("OTC") which owns a polymer grade propylene storage facility and related dock infrastructure (located on the Houston Ship Channel) for loading waterborne propylene vessels. Both the La Porte and OTC investments are considered an integral part of our Mont Belvieu III propylene fractionation operations. These investments are classified as part of our Fractionation operating segment.

The following table shows the aggregate amount of investments in and advances to (and our ownership percentages in) unconsolidated affiliates at June 30, 2002 and December 31, 2001:

	OWNERSHIP PERCENTAGE	JUNE 30, 2002	DECEMBER 31, 2001
Accounted for on equity basis:			
Fractionation:			
BRF	32.25%	$ 28,687	$ 29,417
BRPC	30.00%	18,197	18,841
Promix	33.33%	43,513	45,071
La Porte	50.00%	5,814	
OTC	50.00%	1,818	
Pipeline:			
EPIK	50.00%	14,375	14,280
Wilprise	37.35%	8,663	8,834
Tri-States	33.33%	26,448	26,734
Belle Rose	41.67%	11,211	11,624
Dixie	19.88%	37,284	37,558
Starfish	50.00%	23,777	25,352
Neptune	25.67%	77,226	76,880
Nemo	33.92%	12,211	12,189
Evangeline	49.50%	2,657	2,578
Octane Enhancement:			
BEF	33.33%	58,189	55,843
Accounted for on cost basis:			
Processing:			
VESCO	13.10%	33,000	33,000
Total		$403,070	$398,201

The following table shows equity in income (loss) of unconsolidated affiliates for the three and six months ended June 30, 2002 and 2001:

	OWNERSHIP PERCENTAGE	THREE MONTHS ENDED JUNE 30, 2002	THREE MONTHS ENDED JUNE 30, 2001	SIX MONTHS ENDED JUNE 30, 2002	SIX MONTHS ENDED JUNE 30, 2001
Fractionation:					
BRF	32.25%	$ 743	$ 42	$ 1,292	$ 60
BRPC	30.00%	278	252	527	404
Promix	33.33%	996	1,396	2,039	1,789
La Porte	50.00%	(173)		(265)	
OTC	50.00%	128		18	

	OWNERSHIP PERCENTAGE	THREE MONTHS ENDED JUNE 30, 2002	THREE MONTHS ENDED JUNE 30, 2001	SIX MONTHS ENDED JUNE 30, 2002	SIX MONTHS ENDED JUNE 30, 2001
Pipelines:					
EPIK	50.00%	(54)	(172)	1,629	(1,094)
Wilprise	37.35%	320	85	467	(137)
Tri-States	33.33%	365	135	834	100
Belle Rose	41.67%	40	29	114	(60)
Dixie	19.88%	(156)	69	561	960
Starfish	50.00%	973	1,022	1,785	1,973
Ocean Breeze	25.67%	--	12	--	14
Neptune	25.67%	682	1,095	1,460	1,789
Nemo	33.92%	44	1	22	10
Evangeline	49.50%	5	(149)	(71)	(149)
Octane Enhancement:					
BEF	33.33%	2,877	5,233	5,883	5,402
Total		$7,068	$9,050	$16,295	$11,061

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, the excess cost of which is 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 that 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 and is not amortized. The following table summarizes our excess cost information:

	INITIAL EXCESS COST	UNAMORTIZED BALANCE AT JUNE 30, 2002	UNAMORTIZED BALANCE AT DECEMBER 31, 2001	AMORTIZATION CHARGED TO EQUITY EARNINGS DURING 2002	AMORTIZATION PERIOD
Fractionation segment:					
Promix	$ 7,955	$ 6,794	$ 7,083	$199	20 years
La Porte	873	855	n/a	18	35 years
Pipelines segment: Dixie					
Attributable to pipeline assets	28,448	26,480	26,887	406	35 years
Goodwill	9,246	8,827	8,827	n/a	n/a
Neptune	12,768	12,221	12,404	182	

35 years

Nemo......................

727 708 718 10 35 years

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

The following tables presents summarized income statement information for our unconsolidated investments accounted for under the equity method (for the periods indicated on a 100% basis).

SUMMARIZED INCOME
STATEMENT DATA FOR
THE THREE MONTHS
ENDED ------------

----- JUNE 30,
2002 JUNE 30, 2001

---------------- -

OPERATING NET
OPERATING NET
REVENUES INCOME
INCOME REVENUES
INCOME INCOME ----
---- -------------
------- -------- -
------------ -----
-- Fractionation:
BRF................
$ 5,750 $ 2,295 $
2,305 $ 3,802 $
265 $ 294
BRPC...............
3,150 923 930
3,400 793 842
Promix.............
10,819 3,274 3,285
12,340 4,447 4,487
La
Porte........... -
- (301) (306)
OTC................
1,421 302 258
Pipeline:
EPIK...............
1,577 (117) (109)
792 (375) (348)
Wilprise...........
1,033 855 857 494
224 227 Tri-
States.........
3,680 1,088 1,097
2,321 388 403
Belle
Rose......... 433
95 96 407 13 21
Dixie..............
6,270 (1,853)
(1,191) 8,799
2,001 1,124
Starfish...........
6,714 2,169 1,943
7,051 2,571 2,299
Ocean
Breeze....... 53
39 39
Neptune............
6,926 2,046 2,338
9,362 5,223 5,195
Nemo...............
887 114 118 (27) 2
Evangeline.........
35,551 1,030 9
47,609 1,010 (144)
Octane
Enhancement:
BEF................

58,132 8,570 8,628
76,054 15,509
15,700 -------- --
----- ------- ----
---- ------- -----
--
Total..............
$142,343 $20,490
$20,258 $172,484
$32,081 $30,141
======== =======
======= ========
======= =======

SUMMARIZED INCOME
STATEMENT DATA FOR
THE SIX MONTHS
ENDED ------------

----- JUNE 30,
2002 JUNE 30, 2001

---------------- -

OPERATING NET
OPERATING NET
REVENUES INCOME
INCOME REVENUES
INCOME INCOME ----
---- ------------
------- -------- -
------------ -----
-- Fractionation:
BRF................
$ 10,355 $ 3,960 $
4,007 $ 7,825 $
300 $ 350
BRPC...............
6,102 1,742 1,758
6,833 1,232 1,347
Promix.............
20,683 6,683 6,713
21,343 5,888 5,964
La
Porte........... -
- (535) (541)
OTC................
1,792 109 37

SUMMARIZED INCOME STATEMENT DATA FOR THE SIX MONTHS ENDED

	JUNE 30, 2002			JUNE 30, 2001		
	OPERATING REVENUES	OPERATING INCOME	NET INCOME	OPERATING REVENUES	OPERATING INCOME	NET INCOME
Pipeline:						
EPIK	9,849	3,237	3,257	1,967	(1,782)	(1,725)
Wilprise	1,804	1,248	1,251	893	(378)	(367)
Tri-States	6,780	2,490	2,503	3,953	262	299
Belle Rose	941	271	273	554	(205)	(192)
Dixie	21,398	5,552	3,331	24,036	8,301	4,829
Starfish	13,143	4,105	3,569	13,467	4,390	3,916
Ocean Breeze	--	--	--	87	87	65
Neptune	14,629	5,561	5,645	16,747	8,648	8,581
Nemo	1,282	40	48		(42)	36
Evangeline	61,060	1,880	(170)	47,609	1,010	(144)
Octane Enhancement:						
BEF	106,061	17,548	17,648	113,918	15,922	16,207
Total	$275,879	$53,891	$49,329	$259,232	$43,633	$39,166

6. RECENTLY ISSUED ACCOUNTING STANDARDS

In June 2001, the FASB issued two new pronouncements: SFAS No. 141, "Business Combinations", and SFAS No. 142, "Goodwill and Other Intangible Assets". SFAS No. 141 prohibits the use of the pooling-of-interests method for business combinations initiated after June 30, 2001 and also applies to all business combinations accounted for by the purchase method that are completed after June 30, 2001. There are also transition provisions that apply to business combinations completed before July 1, 2001, that were accounted for by the purchase method. SFAS No. 142 was effective for our fiscal year that began January 1, 2002 for all goodwill and other intangible assets recognized in our consolidated balance sheet at that date, regardless of when those assets were initially recognized.

At December 31, 2001, our intangible assets were comprised of the values associated with the Shell natural gas processing agreement and the goodwill related to the 1999 MBA acquisition. In accordance with SFAS No. 141, we reclassified the MBA goodwill to a separate line item on our consolidated balance sheet apart from the Shell contract. Based upon SFAS No. 142, the value of the Shell natural gas processing agreement will continue to be amortized over its remaining contract term of approximately 18 years; however, amortization of the MBA goodwill will cease. The MBA goodwill will be subject to periodic impairment testing in accordance with SFAS No. 142 due to its indefinite life. For additional information regarding our intangible assets and goodwill (including additions to both classes of assets as a result of the Diamond-Koch acquisitions), see Note 7.

In accordance with the transition provisions of SFAS No. 142, we have completed an impairment review of the December 31, 2001 MBA goodwill balance. Professionals in the business valuation industry were consulted regarding the assumptions and techniques used in our analysis. As a result of this review, no impairment loss was indicated. Any subsequent impairment losses stemming from future goodwill impairment studies will be reflected as a component of operating income in the Statements of Consolidated Operations.

In addition to SFAS No. 141 and No. 142, the FASB also issued SFAS No. 143, "Accounting for Asset Retirement Obligations", in June 2001. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. This statement is effective for our fiscal year beginning January 1, 2003. We are evaluating the provisions of this statement.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. We adopted this statement effective January 1, 2002 and determined that it did not have any significant impact on our financial statements as of that date.

In April 2002, the FASB issued SFAS No. 145, "Rescission of SFAS Statements No. 4, 44, and 64, Amendment of SFAS No. 13, and Technical Corrections." The purpose of this statement is to update, clarify and simplify existing accounting standards. We adopted this statement effective April 30, 2002 and determined that it did not have any significant impact on our financial statements as of that date.

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 operation, 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. This statement is effective for our fiscal year beginning January 1, 2003. We are evaluating the provisions of this statement.

7. INTANGIBLE ASSETS AND GOODWILL

INTANGIBLE ASSETS

Our recorded intangible assets are comprised of the estimated values assigned to contract rights we own arising from agreements with customers. According to SFAS No. 141, 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.

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.

At June 30, 2002, our intangible assets consisted of the Shell natural gas processing agreement that we acquired as part of the TNGL acquisition in August 1999 and certain propylene fractionation and storage contracts we acquired in connection with the Diamond-Koch acquisitions in January and February 2002. The value of the Shell natural gas processing agreement is being amortized on a straight-line basis over its remaining contract term (currently $11.1 million annually from 2002 through 2019). At June 30, 2002, the unamortized value of the Shell contract was $188.8 million.

The value of the propylene fractionation and storage contracts acquired from Diamond-Koch is 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. Although the majority of these contracts have terms of one to two years, we have assumed that our relationship with these customers will extend beyond the contractually-stated term primarily based on historically low customer contract turnover rates within these operations. At June 30, 2002, the unamortized value of these contracts was $60.4 million.

GOODWILL

At June 30, 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 June 30, 2002):

- $73.7 million associated with the purchase of propylene fractionation assets from Diamond-Koch in February 2002; and,

- $7.8 million related to the July 1999 purchase of Kinder Morgan's ownership interest in MBA which in turn owned an interest in our Mont Belvieu NGL fractionation facility.

Since our adoption of SFAS No. 142 on January 1, 2002, our goodwill amounts are no longer amortized. Instead, we periodically review the reporting units to which the goodwill amounts relate for indications of possible impairment. 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. Our goodwill amounts are classified as part of the Fractionation segment since they are related to assets recorded in this operating segment.

The fair value of a reporting unit refers to the amount at which it could be bought or sold in a current transaction between willing parties. Quoted market prices in active markets are the best evidence of fair value and are used to the extent they are available. If quoted market prices are not available, an estimate of fair value is determined based on the best information available to us, including prices of similar assets and the results of using other valuation techniques such as discounted cash flow analysis and multiples of earnings approaches. The underlying assumptions in such models rely on information available to us at a given point in time and are viewed as reasonable and supportable considering available evidence.

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.

PRO FORMA IMPACT OF DISCONTINUATION OF AMORTIZATION OF GOODWILL

The following table discloses the unaudited pro forma impact on earnings of discontinuing amortization of the MBA goodwill (for the three and six months ended June 30, 2001).

	THREE MONTHS ENDED JUNE 30, 2001	SIX MONTHS ENDED JUNE 30, 2001
Reported net income	$93,031	$145,301
Discontinue goodwill amortization	111	222
Adjust minority interest expense	(1)	(2)
Adjusted net income	$93,141	$145,521

On a pro forma basis, earnings per Unit (both basic and diluted) were not affected by the discontinuation of goodwill amortization due to the immaterial nature of the pro forma adjustment.

8. DEBT OBLIGATIONS

Our debt consisted of the following at:

	JUNE 30, 2002	DECEMBER 31, 2001
Borrowings under:		
Senior Notes A, 8.25% fixed rate, due March 2005	$ 350,000	$350,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	450,000
Multi-Year Credit Facility, due November 2005	230,000	
364-Day Credit Facility, due November 2002(a)	138,000	
Total principal amount	1,222,000	854,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,895	1,653
Less unamortized discount on:		
Senior Notes A	(99)	(117)
Senior Notes B	(244)	(258)
Less current maturities of debt	--	--
Long-term debt	$1,223,552	$855,278

- ---------------
(a) Under the terms of this facility, the Operating Partnership has the option to convert this facility into a term loan due November 15, 2003. Management intends to refinance this obligation with a similar obligation at or before maturity.

The above table does not reflect the $1.26 billion in debt we incurred on July 31, 2002 in connection with the Mapletree and E-Oaktree acquisitions (see Note 15 for information regarding this subsequent event).

At June 30, 2002, we had a total of $75 million of standby letters of credit capacity under our Multi-Year Credit Facility of which $9.4 million was outstanding.

Enterprise Products Partners L.P. acts as guarantor of certain of the Operating Partnership's debt obligations. This parent-subsidiary guaranty provision exists under our Senior Notes, MBFC Loan, Multi-Year and 364-Day Credit Facility.

In April 2002, we increased the amount that we can borrow under the Multi-Year Credit Facility by $20 million and the 364-Day Credit Facility by $80 million, up to an amount not exceeding $500 million in the aggregate for both facilities. At June 30, 2002, we had borrowed a total of $368 million under these two facilities.

The indentures under which the Senior Notes and the MBFC Loan were issued contain various restrictive covenants. We were in compliance with these covenants at June 30, 2002.

On April 24, 2002, certain covenants of our Multi-Year and 364-Day Credit Facilities were amended to allow for the commodity hedging losses we incurred during the first four months of 2002. As defined within the second amendment to each of these loan agreements, the changes included allowing us to exclude from the calculation of Consolidated EBITDA up to $50 million in losses resulting from hedging NGLs that utilized natural gas-based financial instruments entered into on or prior to April 24, 2002. This exclusion applies to our quarterly Consolidated EBITDA calculations in which the earnings impact of such specific instruments were recognized. This provision allows for $45.1 million to be added back to Consolidated EBITDA for the first quarter of 2002 and $4.9 million to be added back for the second quarter of 2002. Due to the rolling four-quarter nature of the Consolidated EBITDA calculation, this provision will affect our financial covenants through the first quarter of 2003. In addition, the second amendment temporarily raised the maximum ratio allowed under the Consolidated Indebtedness to Consolidated EBITDA ratio for the rolling-four quarter period ending September 30, 2002 (this provision was superseded by the third amendment to these loan agreements executed on July 31, 2002, see Note 15 for information regarding this subsequent event).

We were in compliance with the covenants of our Multi-Year and 364-Day revolving credit agreements at June 30, 2002.

9. CAPITAL STRUCTURE

CONVERSION OF EPCO SUBORDINATED 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. Should the financial criteria continue to be satisfied through the first quarter of 2003, an additional 25% of the Subordinated Units would undergo an early conversion to Common Units on May 1, 2003. The remaining 50% of Subordinated Units would convert on August 1, 2003 should the balance of the conversion requirements be met. Subordinated Units have no voting rights until converted to Common Units. The conversion(s) will have no impact upon our earnings per unit since the Subordinated Units are already included in both the basic and fully diluted EPU calculations.

CONVERSION OF SHELL SPECIAL UNITS TO COMMON UNITS

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 EPU.

TREASURY UNITS

During the first quarter of 1999, the Operating Partnership established the EPOLP 1999 Grantor Trust (the "Trust") to fund future obligations under EPCO's long-term incentive plan (through the exercise of Common Unit options granted to directors of the General Partner and EPCO employees who participate in the business of the Operating Partnership). The Common Units purchased by the Trust are accounted for in a manner similar to treasury stock under the cost method of accounting. At June 30, 2002, the Trust held 427,200 Common Units that are classified as Treasury Units. The Trust purchased 100,000 Common Units during the first six months of 2002 at a cost of $2.4 million.

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 Trust to repurchase up to 2.0 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 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 to fund future obligations under EPCO's long-term incentive plan (i.e, used for the same intent as that contemplated for the Common Units repurchased by the Trust). The Company purchased 424,459 Common Units during the first six months of 2002 at a cost of $9.3 million. At June 30, 2002, 677,900 Common Units could be repurchased under the Buy-Back Program.

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

COMPREHENSIVE INCOME

We report comprehensive income or loss in our Statements of Consolidated Partners' Equity and Comprehensive Income. For the six months ended June 30, 2001, the cumulative transition adjustment resulting from the adoption of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended and interpreted, was the only item of other comprehensive income for us. There were no differences between net income and comprehensive income for the same period in 2002. The following table summarizes the activity in other comprehensive income for the six months ended June 30, 2001.

COMPREHENSIVE INCOME
FOR THE SIX MONTHS ENDED JUNE 30, 2001

Net Income...	$145,301
Less: Accumulated Other Comprehensive Loss.................	(9,711)
Comprehensive Income.......................................	$135,590

10. 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 operating losses, the Special Units are excluded from the calculation of diluted earnings per Unit due to their antidilutive effect. The following table reconciles the number of Units used in the calculation of basic earnings per Unit and diluted earnings per Unit for the three and six months ended June 30, 2002 and 2001.

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2002	2001	2002	2001
Income before minority interest..................	$ 22,523	$ 93,975	$ 5,147	$146,779
General partner interest..........................	(2,648)	(1,388)	(3,894)	(2,370)
Income before minority interest available to Limited Partners................................	19,875	92,587	1,253	144,409
Minority interest.................................	(203)	(944)	(30)	(1,478)
Net income available to Limited Partners...........	$ 19,672	$ 91,643	$ 1,223	$142,931

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2002	2001	2002	2001
BASIC EARNINGS PER UNIT				
NUMERATOR				
Income before minority interest available to Limited Partners	$ 19,875	$ 92,587	$ 1,253	$144,409
Net income available to Limited Partners	$ 19,672	$ 91,643	$ 1,223	$142,931
DENOMINATOR				
Common Units outstanding	109,640	92,514	106,192	92,514
Subordinated Units outstanding	35,644	42,820	39,212	42,820
Total	145,284	135,334	145,404	135,334
BASIC EARNINGS PER UNIT				
Income before minority interest available to Limited Partners	$ 0.14	$ 0.68	$ 0.01	$ 1.07
Net income available to Limited Partners	$ 0.14	$ 0.68	$ 0.01	$ 1.06
DILUTED EARNINGS PER UNIT				
NUMERATOR				
Income before minority interest available to Limited Partners	$ 19,875	$ 92,587	$ 1,253	$144,409
Net income available to Limited Partners	$ 19,672	$ 91,643	$ 1,223	$142,931
DENOMINATOR				
Common Units outstanding	109,640	92,514	106,192	92,514
Subordinated Units outstanding	35,644	42,820	39,212	42,820
Special Units outstanding	29,000	33,000	29,000	33,000
Total	174,284	168,334	174,404	168,334
DILUTED EARNINGS PER UNIT				
Income before minority interest available to Limited Partners	$ 0.11	$ 0.55	$ 0.01	$ 0.86
Net income available to Limited Partners	$ 0.11	$ 0.54	$ 0.01	$ 0.85

11. DISTRIBUTIONS

We intend, to the extent there is sufficient available cash from Operating Surplus, as defined by the Partnership Agreement, to distribute to each holder of Common Units at least a minimum quarterly distribution of $0.225 per Common Unit. The minimum quarterly distribution is not guaranteed and is subject to adjustment as set forth in the Partnership Agreement. Apart from its pro rata share of the quarterly distributions, the General Partner's interest in quarterly distributions is increased after certain specified target levels are met (the "incentive distributions").

The distribution paid on February 11, 2002 (based on fourth quarter 2001 results) was $0.3125 per Common and Subordinated Unit. The distribution paid on May 10, 2002 (based on first quarter 2002 results) was $0.335 per Common and Subordinated Unit. As a result of these distributions, the General Partner received $3.9 million in incentive distributions.

The distribution rate declared by the General Partner for the second quarter of 2002 was $0.335 per Common Unit to Unitholders of record on July 31, 2002. This distribution was paid on August 12, 2002.

12. SUPPLEMENTAL CASH FLOWS DISCLOSURE

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

	SIX MONTHS ENDED JUNE 30,	
	2002	2001
(Increase) decrease in:		
Accounts and notes receivable	$(24,455)	$ 96,860
Inventories	(78,843)	522
Prepaid and other current assets	9,599	(10,831)
Other assets	(3,436)	(129)
Increase (decrease) in:		
Accounts payable	7,795	(55,755)
Accrued gas payable	70,447	(78,008)
Accrued expenses	(9,499)	(11,232)
Accrued interest	374	14,546
Other current liabilities	(4,219)	13,271
Other liabilities	(142)	187
Net effect of changes in operating accounts	$(32,379)	$(30,569)

During the first six months of 2002, we completed $394.8 million in business acquisitions of which the purchase price allocations of each affected various balance sheet accounts. See Note 2 for information regarding the allocation of the purchase price for these acquisitions.

The $32.5 million purchase price obligation of the Toca-Western facilities will not be paid until September 2002. This amount was accrued as additional property, plant and equipment with the offsetting payable amount recorded under other current liabilities (see Note 2).

We record various financial instruments relating to commodity positions and interest rate swaps at their respective fair values using mark-to-market accounting. For the six months ended June 30, 2002, we recognized a net $19.7 million in non-cash changes related to decreases in the fair value of these financial instruments, primarily in our commodity financial instruments portfolio. For the six months ended June 30, 2001, we recognized a net $55.9 million in non-cash mark-to-market income from our financial instruments portfolio.

Cash and cash equivalents at June 30, 2002, per the Statements of Consolidated Cash Flows, excludes $5.0 million of restricted cash. This restricted cash represents 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.

Of the $9.3 million spent by the Company for Treasury Units during the first six months of 2002, $0.7 million will not result in cash settlements until July 2002.

13. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices in our natural gas and NGL businesses and in interest rates with respect to a portion of our debt obligations. 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 in our Processing segment. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

COMMODITY FINANCIAL INSTRUMENTS

Our Processing and Octane Enhancement segments are directly exposed to commodity price risk through their respective business operations. The prices of natural gas, NGLs 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, we may enter into swaps, forwards, commodity futures, options and other commodity financial instruments with similar characteristics that are permitted by contract or business custom to be settled in cash or with another financial instrument. The primary purpose of these risk management activities (or hedging strategies) is to hedge exposure to price risks associated with natural gas, NGL inventories, firm commitments and certain anticipated transactions. We do not hedge our exposure to the MTBE markets. Also, in our Pipelines segment, we may utilize a limited number of commodity financial instruments to manage the price we charge certain of our customers for natural gas.

We have adopted a financial commodity and commercial policy to manage our exposure to the risks of our natural gas and NGL businesses. The objective of these policies 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. Under these policies, 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 one month) and long-term basis, generally not to exceed 24 months. The General Partner oversees our hedging strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policies (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policies.

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.

Our commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133 because of ineffectiveness. A hedge is normally regarded as effective if, among other things, at inception and throughout the term of the financial instrument, we could expect changes in the fair value of the hedged item to be almost fully offset by the changes in the fair value of the financial instrument. When financial instruments do not qualify as effective hedges under the guidelines of SFAS No. 133, changes in the fair value of these positions are recorded on the balance sheet and in earnings through mark-to-market accounting. The use of mark-to-market accounting for these ineffective instruments results in a degree of non-cash earnings volatility that is dependent upon changes in the underlying commodity prices.

We recognized a loss of $50.9 million in the first six months of 2002 from our commodity hedging activities, of which $45.1 million was attributable to the first quarter of 2002. These losses are treated as an increase in operating costs and expenses in our Statements of Consolidated Operations. Of this amount, $31.9 million has been realized (e.g., paid out to counterparties). The remaining $19.0 million represents the negative change in value of the open positions between December 31, 2001 and June 30, 2002 (based on market prices at those dates). The market value of our open positions at June 30, 2002 was $11.1 million payable (a loss).

For the first six months of 2001, we recognized income of $70.3 million from these activities of which $5.6 million was recorded in the first quarter and $64.7 million in the second quarter. Of the $70.3 million recorded for the first six months of 2001, $52.4 million was attributable to the market value of open positions at June 30, 2001.

INTEREST RATE SWAPS

Our interest rate exposure results from variable-rate borrowings from commercial banks and fixed-rate borrowings pursuant to the Company's Senior Notes and MBFC Loan. We manage a portion of our exposure to changes in interest rates by utilizing interest rate swaps. The objective of holding 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. An interest rate swap, in general, requires one party to pay a fixed-rate on the notional amount while the other party pays a floating-rate based on the notional amount.

The General Partner oversees the strategies associated with financial risks and approves instruments that are appropriate for our requirements. At June 30, 2002, we had one interest rate swap outstanding having a notional amount of $54 million extending through March 2010. Under this agreement, we exchanged a fixed-rate of 8.70% for a market-based variable-rate. If it elects to do so, the counterparty may terminate this swap in March 2003.

We recognized income of $0.8 million during the first six months of 2002 from our interest rate swaps that is treated as a reduction of interest expense ($0.7 million recorded in the second quarter of 2002). The fair value of the interest rate swap at June 30, 2002 was a receivable of $3.1 million. We recognized income of $5.5 million during the first six months of 2001 from interest rate swaps. The benefit recorded in 2001 was primarily due to the election of a counterparty to not terminate its interest rate swap in the first quarter of 2001.

14. SEGMENT INFORMATION

Operating segments are components of a business about which separate financial information is available and that 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 both liquids 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 merchant 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 other plant support functions.

We evaluate segment performance based on 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 interest expense, interest income (from unconsolidated affiliates or others), dividend income from unconsolidated affiliates, minority interest, extraordinary charges and other income and expense transactions.

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 merchant activities group (an intersegment revenue of Fractionation offset by an intersegment expense of Processing);

- liquids pipeline revenues from transporting our merchant volumes from the 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 sale of our NGL equity production extracted by our gas processing plants to our merchant activities group (an intrasegment revenue of Processing offset by an intrasegment expense of Processing).

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 segment gross operating margin and as a component of revenues. 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 these businesses 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 merchant businesses. 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.

Our revenues are derived from a wide customer base. All consolidated revenues were earned in the United States. Our operations are centered along the Texas, Louisiana and Mississippi Gulf Coast areas. See Note 15 regarding an expansion of our business activities into certain regions of the central and western United States.

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.

A reconciliation of segment gross operating margin to consolidated income before minority interest follows:

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2002	2001	2002	2001
Total segment gross operating margin.......	$ 66,938	$131,255	$ 93,351	$204,148
Depreciation and amortization............	(16,962)	(11,793)	(34,199)	(21,822)
Retained lease expense, net..............	(2,273)	(2,660)	(4,578)	(5,320)
(Gain) loss on sale of assets............	1	6	(12)	387
Selling, general and administrative......	(7,740)	(7,737)	(15,702)	(13,905)
Consolidated operating income.............	39,964	109,071	38,860	163,488
Interest expense.........................	(19,032)	(16,331)	(37,545)	(23,318)
Interest income from unconsolidated affiliates...........................	62	7	92	31
Dividend income from unconsolidated affiliates...........................	1,242	--	2,196	1,632
Interest income -- other.................	241	1,479	1,575	5,477
Other, net...............................	46	(251)	(31)	(531)
Consolidated income before minority interest................................	$ 22,523	$ 93,975	$ 5,147	$146,779

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

OPERATING SEGMENTS -----------

--------------------- ADJS.
OCTANE AND CONSOL.
FRACTIONATION PIPELINES
PROCESSING ENHANCEMENT OTHER
ELIMS. TOTALS ------------- --
------- ---------- -----------
------- --------- ----------
Revenues from external
customers: Three months ended
June 30,
2002..........................
$169,345 $138,589 $ 477,941 $
382 $ 786,257 Three months
ended June 30,
2001..........................
86,566 178,958 693,242 631
959,397 Six months ended June
30, 2002... 278,767 237,670
930,975 899 1,448,311 Six
months ended June 30, 2001...
176,245 186,145 1,432,011
1,311 1,795,712 Intersegment
and intrasegment revenues:
Three months ended June 30,
2002..........................
56,103 25,578 140,969 102
$(222,752) Three months ended
June 30,
2001..........................
44,133 24,631 131,657 96
(200,517) Six months ended
June 30, 2002... 89,500 50,088
267,229 202 (407,019) Six
months ended June 30, 2001...
85,785 45,410 241,966 191
(373,352) Equity income in
unconsolidated affiliates:
Three months ended June 30,
2002..........................
1,973 2,219 $ 2,876 7,068
Three months ended June 30,
2001..........................
1,692 2,125 5,233 9,050 Six
months ended June 30, 2002...
3,612 6,801 5,882 16,295 Six
months ended June 30, 2001...
2,253 3,406 5,402 11,061 Total
revenues: Three months ended
June 30,
2002..........................
227,421 166,386 618,910 2,876
484 (222,752) 793,325 Three
months ended June 30,
2001..........................
132,391 205,714 824,899 5,233
727 (200,517) 968,447 Six
months ended June 30, 2002...
371,879 294,559 1,198,204
5,882 1,101 (407,019)
1,464,606 Six months ended
June 30, 2001... 264,283
234,961 1,673,977 5,402 1,502
(373,352) 1,806,773 Total
gross operating margin by
segment: Three months ended
June 30,
2002..........................
33,853 32,190 (1,182) 2,876
(799) 66,938 Three months
ended June 30,

2001.......................... 32,803 24,696 68,112 5,233 411 131,255 Six months ended June 30, 2002... 58,230 64,858 (34,558) 5,882 (1,061) 93,351 Six months ended June 30, 2001... 58,471 42,819 96,510 5,402 946 204,148 Segment assets: At June 30, 2002................. 470,249 918,052 129,028 9,239 44,003 1,570,571 At December 31, 2001............. 357,122 717,348 124,555 8,921 98,844 1,306,790 Investments in and advances to unconsolidated affiliates: At June 30, 2002................. 98,029 213,852 33,000 58,189 403,070 At December 31, 2001............. 93,329 216,029 33,000 55,843 398,201 Intangible Assets: At June 30, 2002................. 52,369 8,011 188,842 249,222 At December 31, 2001............. 7,857 194,369 202,226 Goodwill: At June 30, 2002................. 81,543 81,543

Total revenues for the second quarter of 2002 were lower than those of the second quarter of 2001 primarily due to a decline in NGL product prices between the two periods. The same can be said for the difference between the first six months of 2002 compared to the same period in 2001. Total gross operating margin for the second quarter of 2002 decreased $64.3 million from the second quarter of 2001 primarily due to the 2001 period including $64.7 million of commodity hedging income in the Processing segment that was not repeated in the 2002 period. For the first six months of 2002, gross operating margin decreased $110.8 million compared to the first six months of 2001. The year-to-date decline in gross operating margin is primarily due to the 2002 period including $50.9 million in commodity hedging losses versus the 2001 period including $70.3 million in commodity hedging income (together accounting for $121.2 million of the year-to-date difference in gross operating margin). The $121.2 million difference in commodity hedging results is primarily reflected in the Processing segment.

Since January 1, 2002, segment assets have increased $263.8 million. The increase is primarily due to the Diamond-Koch acquisitions completed during the first quarter of 2002 and the Toca-Western acquisition in June 2002 (see Note 2). Intangible assets increased $47.0 million since January 1, 2002 primarily the result of the contract-based intangible assets we acquired from Diamond-Koch (see Note 7). Goodwill was $81.5 million at June 30, 2002 due to the goodwill we added as a result of the Diamond-Koch acquisition and the reclassification of the goodwill associated with the 1999 MBA acquisition (see Note 7).

15. SUBSEQUENT EVENTS

PURCHASE OF INTERESTS IN MAPLETREE AND E-OAKTREE

On August 1, 2002, we announced the purchase of equity interests in affiliates of Williams, which in turn, own controlling interests in Mid-America Pipeline Company, LLC (formerly Mid-America Pipeline Company) and Seminole Pipeline Company. The purchase price of the acquisition was approximately $1.2 billion (subject to certain post-closing purchase price adjustments). The effective date of the acquisition was July 31, 2002.

The acquisitions include a 98% ownership interest in Mapletree, LLC ("Mapletree"), owner of a 100% interest in Mid-America Pipeline Company, LLC and certain propane terminals. The Mid-America pipeline is a major NGL pipeline system consisting of three NGL pipelines, with 7,226 miles of pipeline, and average transportation volumes of approximately 850 MBPD. Mid-America's 2,548-mile Rocky Mountain system transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to Hobbs, Texas. Its 2,740-mile Conway North segment links the large NGL hub at Conway, Kansas to the upper Midwest; its 1,938 mile Conway South system connects the Conway hub with Kansas refineries and transports mixed NGLs from Conway, Kansas to Hobbs, Texas.

We also acquired a 98% ownership interest in E-Oaktree, LLC, owner of an 80% equity interest in Seminole Pipeline Company. The Seminole pipeline consists of a 1,281-mile NGL pipeline, with an average transportation volume of approximately 260 MBPD. This pipeline transports mixed NGLs and NGL products from Hobbs, Texas and the Permian Basin to Mont Belvieu, Texas.

The post-closing purchase price adjustments of the Mapletree and E-Oaktree acquisitions are expected to be completed during the fourth quarter of 2002. These acquisitions do not require any material governmental approvals.

These acquisitions were funded by a $1.2 billion senior unsecured 364-day term loan entered into by the Operating Partnership on July 31, 2002. The lenders under this facility are Wachovia Bank, National Association; Lehman Brothers Bank, FSB; Lehman Commercial Paper Inc. and Royal Bank of Canada. As defined within the credit agreement, the loan will generally bear interest at either (i) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent or (ii) a Eurodollar rate, with any rate in effect being increased by an appropriate applicable margin. The credit agreement contains various affirmative and negative covenants applicable to the Operating Partnership similar to those required under our Multi-Year and 364-Day Credit Facility agreements. The $1.2 billion term loan is guaranteed by Enterprise Products Partners L.P. through an unsecured guarantee. The loan will be repaid as follows: $150 million due on December 31, 2002, $450 million on March 31, 2003 and $600 million on July 30, 2003.

On August 1, 2002, Seminole Pipeline Company had $60 million in senior unsecured notes due in December 2005. The principal amount of these notes amortize by $15 million each December 1 through

2005. In accordance with GAAP, this debt will be consolidated on our balance sheet because of our 98% controlling interest in E-Oaktree, LLC, which owns 80% of Seminole Pipeline Company.

THIRD AMENDMENT TO OUR MULTI-YEAR AND 364-DAY CREDIT FACILITIES

On July 31, 2002, certain covenants of our Multi-Year and 364-Day Credit Facilities were further amended to allow for increased financial flexibility in light of the Mapletree and E-Oaktree acquisitions. As defined within the third amendment to each of these loan agreements, the maximum ratio of Consolidated Indebtedness to Consolidated EBITDA allowed by our lenders was increased as follows from that noted in the second amendment issued in April 2002:

CHANGES MADE TO THE CONSOLIDATED INDEBTEDNESS TO CONSOLIDATED EBITDA RATIO

CALCULATION MADE FOR THE ROLLING FOUR-QUARTER PERIOD ENDING	MAXIMUM RATIO ALLOWED: OLD PROVISIONS UNDER 2ND AMENDMENT	MAXIMUM RATIO ALLOWED: NEW PROVISIONS UNDER 3RD AMENDMENT
September 30, 2002	4.50 to 1.0	6.00 to 1.0
December 31, 2002	4.00 to 1.0	5.25 to 1.0
March 31, 2003	4.00 to 1.0	5.25 to 1.0
June 30, 2003	4.00 to 1.0	4.50 to 1.0
September 30, 2003 and for each rolling-four quarter period thereafter	4.00 to 1.0	4.00 to 1.0

In addition, the negative covenant on Indebtedness (as defined within the Multi-Year and 364-Day credit agreements) was amended to permit the Seminole Pipeline Company indebtedness assumed in connection with the acquisition of E-Oaktree.

REPORT OF INDEPENDENT AUDITORS

The Board of Directors of
The Williams Companies, Inc.:

We have audited the accompanying combined balance sheets of Mid-America Pipeline System (A Division of The Williams Companies, Inc.) (See Note 1) as of December 31, 2000 and 2001 and the related combined statements of operations and owner equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of The Williams Companies, Inc.'s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the combined financial statements referred to above present fairly, in all material respects, the combined financial position of Mid-America Pipeline System (A Division of The Williams Companies, Inc.) (See Note 1) at December 31, 2000 and 2001 and the combined results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

ERNST & YOUNG LLP

Tulsa, Oklahoma
September 6, 2002

MID-AMERICA PIPELINE SYSTEM
(A DIVISION OF THE WILLIAMS COMPANIES, INC.)

COMBINED STATEMENTS OF OPERATIONS AND OWNER EQUITY

	FOR YEARS ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	1999	2000	2001	2001	2002
				(UNAUDITED)	
	(DOLLARS IN THOUSANDS)				
REVENUES	$190,686	$209,895	$214,518	$102,244	$109,865
COSTS AND EXPENSES					
Operating costs and expenses	87,623	105,591	125,349	67,870	45,111
Selling, general and administrative	28,718	29,307	28,364	13,807	15,130
Total	116,341	134,898	153,713	81,677	60,241
OPERATING INCOME	74,345	74,997	60,805	20,567	49,624
OTHER INCOME (EXPENSE)					
Interest expense	(7,673)	(13,500)	(12,700)	(6,947)	(4,432)
Other, net	822	880	(1,035)	89	(748)
Total	(6,851)	(12,620)	(13,735)	(6,858)	(5,180)
INCOME BEFORE INCOME TAXES	67,494	62,377	47,070	13,709	44,444
PROVISION FOR INCOME TAXES	(23,651)	(22,826)	(17,445)	(4,894)	(16,604)
NET INCOME	$ 43,843	$ 39,551	$ 29,625	$ 8,815	$ 27,840
DIVIDEND OF ASSETS	--	(4,127)	--	--	(23,571)
OWNER CONTRIBUTION	--	--	--	--	34,381
OWNER EQUITY AT BEGINNING OF PERIOD	278,917	322,760	358,184	358,184	387,809
OWNER EQUITY AT END OF PERIOD	$322,760	$358,184	$387,809	$366,999	$426,459

See Notes to Financial Statements

MID-AMERICA PIPELINE SYSTEM
(A DIVISION OF THE WILLIAMS COMPANIES, INC.)

COMBINED BALANCE SHEETS

	DECEMBER 31, 2000	DECEMBER 31, 2001	JUNE 30, 2002 (UNAUDITED)
	(DOLLARS IN THOUSANDS)		
ASSETS			
CURRENT ASSETS			
Accounts receivable -- affiliates	$ 9,396	$ 16,181	$ 20,506
Accounts receivable -- other	743	540	1,383
Income taxes due from affiliates	8,213	--	11,855
Product inventory	30,562	15,416	10,210
Prepaid and other current assets	4,283	2,017	868
Total current assets	53,197	34,154	44,822
PROPERTY, PLANT AND EQUIPMENT, NET	680,735	673,627	633,937
OTHER ASSETS	2,851	3,054	2,844
TOTAL	$736,783	$710,835	$681,603
LIABILITIES AND STOCKHOLDERS' EQUITY			
CURRENT LIABILITIES			
Accounts payable -- trade	$ 7,263	$ 6,518	$ 5,178
Accounts payable -- affiliates	163,552	93,292	26,726
Income taxes due to affiliates	--	381	--
Accrued taxes, other than income taxes	4,616	5,400	7,777
Other current liabilities	475	1,951	2,468
Total current liabilities	175,906	107,542	42,149
LONG-TERM DEBT	90,000	90,000	90,000
DEFERRED INCOME TAXES	112,351	119,259	122,611
OTHER LONG-TERM LIABILITIES	342	6,225	384
COMMITMENTS			
OWNER EQUITY	358,184	387,809	426,459
TOTAL	$736,783	$710,835	$681,603

See Notes to Financial Statements

MID-AMERICA PIPELINE SYSTEM
(A DIVISION OF THE WILLIAMS COMPANIES, INC.)

COMBINED STATEMENTS OF CASH FLOWS

	FOR YEARS ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	1999	2000	2001	2001	2002
				(UNAUDITED)	
	(DOLLARS IN THOUSANDS)				
OPERATING ACTIVITIES					
Net income..............................	$ 43,843	$ 39,551	$ 29,625	$ 8,815	$ 27,840
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:					
Depreciation..........................	19,020	25,000	25,001	12,392	12,291
Lower of cost or market adjustment.....	--	--	18,833	12,903	--
Deferred income taxes..................	13,048	7,175	7,060	1,892	3,196
Net effect of changes in operating accounts...........................	48,456	(51,002)	(62,626)	(32,600)	(41,237)
Operating activities cash flows.....	124,367	20,724	17,893	3,402	2,090
INVESTING ACTIVITIES					
Capital expenditures....................	(137,427)	(20,844)	(18,573)	(3,534)	(2,192)
Proceeds from sale of assets.............	13,060	120	680	132	102
Investing activities cash flows.....	(124,367)	(20,724)	(17,893)	(3,402)	(2,090)
CHANGE IN CASH AND CASH EQUIVALENTS......	--	--	--	--	--
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD................................	--	--	--	--	--
CASH AND CASH EQUIVALENTS AT END OF PERIOD................................	$ --	$ --	$ --	$ --	$ --

See Notes to Financial Statements

NOTES TO COMBINED FINANCIAL STATEMENTS
(INFORMATION PERTAINING TO JUNE 30, 2002 AND TO THE
SIX MONTHS ENDED JUNE 30, 2001 AND 2002 IS UNAUDITED)

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements and accompanying notes represent the combined historical financial information of (i) Mid-America Pipeline Company ("MAPL") and (ii) certain terminals and storage facilities ("Terminals and Storage"), all of which is owned by The Williams Companies, Inc. Unless the context requires otherwise, references to "we", "us", "our", or the "Company" are intended to mean MAPL and the Terminals and Storage facilities. In addition, references to "Williams" in these footnotes are intended to mean The Williams Companies, Inc. and its affiliates.

MAPL, a Delaware corporation, was organized in May 1968 for the purpose of owning and operating a natural gas liquids ("NGLs") pipeline. Since its formation, MAPL's operations have expanded to include the transportation, pumping, metering and underground storage of a variety of NGLs, including demethanized mix, ethane-propane mix and specification liquid products. Our primary asset is the pipeline system located in the Rocky Mountains, the Midwest and a portion of the Southwest United States. Approximately 20 natural gas processing plants in Wyoming, Utah and Colorado feed NGLs into the MAPL system for delivery to several destinations.

The Terminals and Storage facilities, were contributed by Williams to Sapling LLC ("Sapling"), a Delaware corporation, organized in July 2002 by Williams. The MAPL system serves the Midwestern U.S. heating market via Sapling's 16 propane truck-loading terminals located on the MAPL system. Sapling also owns underground NGL storage capacity that provides operating flexibility along the MAPL system.

Also in July 2002, Williams converted MAPL from a corporation to a limited liability company, Mid-America Pipeline Company, LLC ("MAPL, LLC"). Williams then contributed Sapling to MAPL, LLC. On July 31, 2002, Williams contributed its 100% equity interest in MAPL, LLC to a newly formed affiliate of Williams, Mapletree, LLC. This contribution was done as part of a subsequent transaction that took place between Williams and Enterprise Products Operating L.P ("EPOLP") on the same date, whereby EPOLP purchased a 98% equity interest in Mapletree, LLC for $940.2 million.

Immediately prior to the sale of 98% of Williams' membership interest in MAPL, LLC to EPOLP, all long-term debt of MAPL, LLC was repaid.

The interim financial data is unaudited; however, in the opinion of management, the interim financial data includes all adjustments, consisting of normal recurring adjustments, necessary for a fair presentation of the financial position as of June 30, 2002 and the results of operations for the six-month periods ended June 30, 2001 and 2002. The results of operations for the six months ended June 30, 2001 and 2002 are not necessarily indicative of the results to be expected for the full year.

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

ENVIRONMENTAL expenditures that relate to current or future revenues are expensed or capitalized based upon the nature of the expenditures. Expenditures resulting from an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Environmental liabilities are recorded independently of any potential claim for recovery. Receivables are recognized in cases where the realization of reimbursements of remediation costs are considered probable. Accruals related to environmental matters are generally determined based on site-specific plans for remediation, taking into account the prior remediation experience of the Company.

INCOME TAXES are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of the Company's assets and liabilities. For federal income tax reporting, the Company is included in Williams' consolidated tax return. The provision for income taxes has been charged to the Company as if separate income tax returns were filed.

LONG-LIVED ASSETS are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Long-lived assets that are held for disposal are valued at the lower of carrying amount or fair value less cost to sell.

PRODUCT INVENTORY consists of various NGL products we utilize in the operation of our pipeline. Product inventory is valued at the lower of average cost or market. For the year ended December 31, 2001, operating costs and expenses include a lower of average cost or market adjustment of $18.8 million.

PROPERTY, PLANT AND EQUIPMENT is recorded at cost and is depreciated using the straight-line method over the asset's estimated useful life at annual rates ranging from 1.40% to 11.30%. Expenditures for maintenance and repairs are charged to operations in the period incurred.

REVENUE is based on tariffs charged to customers for pipeline volumes transported. Shippers are invoiced and the related revenue is recorded as deliveries are made.

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. Our actual results could differ from these estimates.

2. RECENTLY ISSUED ACCOUNTING STANDARDS

The Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations" in June 2001. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. This statement is effective for our fiscal year beginning January 1, 2003. We are evaluating the provisions of this statement.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. We adopted this statement effective January 1, 2002 and determined that it did not have any significant impact on our financial statements as of that date.

In April 2002, the FASB issued SFAS No. 145, "Rescission of SFAS Statements No. 4, 44, and 64, Amendment of SFAS No. 13, and Technical Corrections." The purpose of this statement is to update, clarify and simplify existing accounting standards. We adopted this statement effective April 30, 2002 and determined that it did not have any significant impact on our financial statements as of that date. 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. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operation, 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. This statement is effective for our fiscal year beginning January 1, 2003. We are evaluating the provisions of this statement.

3. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consists of the following at the periods indicated:

	DECEMBER 31,		JUNE 30,
	2000	2001	2002
			(UNAUDITED)
Pipelines and related equipment	$ 970,393	$981,733	$ 943,115
Land	1,303	1,445	1,445
Total	971,696	983,178	944,560
Less accumulated depreciation	(290,961)	(309,551)	(310,623)
Property, plant and equipment, net	$ 680,735	$673,627	$ 633,937

During 1999, we capitalized $7.0 million of interest related to a pipeline expansion project.

During 2002, we contributed fixed assets with a net book value of $23.6 million to an affiliate of Williams. The transaction was accounted for as a non-cash dividend.

4. LONG-TERM DEBT

During 1992, we issued five different series of Senior Unsecured Notes in the private placement market. The notes have a combined principal balance of $90 million with interest rates between 8.20% to 8.95%. The notes have principal payments beginning in July 2007. Interest is paid semi-annually either January 1 and July 1 or April 30 and October 30. The note agreements contain restrictive covenants, which limit the payment of advances or dividends to stockholders and restrict additional borrowing of funds. Such provisions restricted $100 million of combined net worth related to MAPL at December 31, 2001. We were in compliance with these covenants at December 31, 2001.

5. INCOME TAXES

The provision for income taxes are as follows for the periods indicated:

	FOR YEARS ENDED DECEMBER 31,		
	1999	2000	2001
Current:			
Federal	$ 9,327	$15,342	$ 9,718
State	1,276	309	667
	10,603	15,651	10,385
Deferred:			
Federal	11,702	6,088	6,105
State	1,346	1,087	955
Provision for income taxes	$23,651	$22,826	$17,445

Reconciliations from the provision for income taxes at the U.S. federal statutory rate to the effective tax rate for the provision for income taxes are as follows:

	FOR YEARS ENDED DECEMBER 31,		
	1999	2000	2001
Provision at statutory rate	$23,623	$21,832	$16,474
Increases (reductions) in taxes resulting from:			
State income taxes (net of federal benefit)	1,704	907	1,054
Other	(1,676)	87	(83)
Provision for income taxes	$23,651	$22,826	$17,445

Significant components of deferred tax liabilities and assets as of December 31, 2000 and 2001 are as follows:

	DECEMBER 31,	
	2000	2001
Deferred tax liabilities:		
Property, plant and equipment	$115,474	$122,138
Other	--	338
Total deferred tax liabilities	115,474	122,476
Deferred tax assets:		
Accrued liabilities	167	140
Other	2,956	3,077
Total deferred tax assets	3,123	3,217
Net deferred tax liabilities	$112,351	$119,259

6. RELATED PARTY TRANSACTIONS

Williams' affiliated companies transport product in our pipelines. Operating revenues from affiliates were as follows:

	FOR YEARS ENDED DECEMBER 31,		
	1999	2000	2001
Revenues from affiliates	$30,328	$40,531	$46,954
Revenues from affiliates as a percentage of total revenues	16%	19%	22%

At December 31, 2000 and 2001, we held affiliate receivable balances of $8.5 million and $14.3 million respectively, from Seminole Pipeline Company ("Seminole"), an 80%-owned subsidiary of Williams, primarily for MAPL's share of the joint tariff on movements generated in MAPL's pipeline system. MAPL is paid for its share of the joint tariff following delivery of NGLs to destinations on Seminole's pipeline system.

Williams charges their affiliates for certain general and administrative expenses that are directly identifiable or allocable to the affiliates. The majority of these expenses are reflected within general and administrative expenses. Allocated general and administrative expenses are based on a three-factor formula, which is accepted by the Federal Energy Regulatory Commission and considers operating margins, property, plant and equipment and payroll. These allocated costs from various Williams subsidiaries were as follows:

	FOR YEARS ENDED DECEMBER 31,		
	1999	2000	2001
Allocated G&A expenses	$23,321	$26,783	$19,067

In addition to the above allocations, Williams allocates interest based on intercompany account balances. Allocated interest expense from Williams was as follows:

	FOR YEARS ENDED DECEMBER 31,		
	1999	2000	2001
Allocated Interest Expense	$6,931	$5,620	$4,300

Due to MAPL holding no cash, Williams pays all MAPL payables, causing us to hold payables to affiliates. Collections on our receivables are netted against the affiliate payable account.

7. MAJOR CUSTOMERS

Two non-affiliated shippers accounted for 18% and 12% of operating revenues for the year ended December 31, 1999. One non-affiliated shipper accounted for 21% and 17% of operating revenues for the years ended December 31, 2000 and 2001.

8. COMMITMENTS

During 2001, we leased certain fixed asset equipment under a 15-year capital lease. At December 31, 2001, the lease had a balance of $5.8 million and an implied interest rate of approximately 14%. The balance of the lease along with the associated fixed assets were transferred to an affiliate in April 2002.

9. SUPPLEMENTAL CASH FLOWS DISCLOSURE

	FOR YEARS ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	1999	2000	2001	2001	2002
				(UNAUDITED)	
(Increase) decrease in:					
Accounts receivable	$(2,124)	$ (544)	$ (6,582)	$ (5,358)	$ (5,168)
Income taxes due from affiliates	--	(8,213)	8,213	3,076	(11,855)
Product inventory	--	(41,455)	(3,687)	(1,162)	5,206
Prepaid and other current assets	(346)	(3,392)	2,266	1,633	1,149
Other assets	1,948	183	(203)	(68)	210
Increase (decrease) in:					
Accounts payable	54,124	23,646	(71,005)	(33,906)	(33,530)
Accrued taxes	(2,579)	(14,516)	1,160	2,863	2,001
Other current liabilities	(1,762)	(6,370)	1,329	322	809
Other liabilities	(805)	(341)	5,883	--	(59)
Net effect of changes in operating accounts	$48,456	$(51,002)	$(62,626)	$(32,600)	

$(41,237) ======= ======== ========
======== ========

Income taxes paid were $12.8 million, $39.4 million and $2.0 million for the year ended December 31, 1999, 2000 and 2001, respectively, and $25.6 million for the six months ended June 30, 2002. No income taxes were paid during the six months ended June 30, 2001. Interest paid was $7.8 million, $8.4 million and $13.0 million for 1999, 2000 and 2001, respectively, and $6.3 million and $3.6 million for the six months ended June 30, 2001 and 2002, respectively.

During 2002, Williams made an equity contribution to us in the amount of $34.4 million. The non-cash transaction was accounted for as a reduction to accounts payable -- affiliate and an increase to owner equity.

10. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following disclosure of estimated fair value was determined by us, using available market information and appropriate valuation methodologies. Considerable judgment, however, is necessary to interpret market data and develop the related estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize upon disposition of the financial instruments. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

Long-term debt. Debt consists of private placement senior notes. The fair value of private debt is valued based on the prices of similar securities with similar terms and credit ratings.

The carrying amounts and fair values for our financial instruments at December 31, 2000 and 2001 are as follows:

	2000		2001	
	CARRYING VALUE	FAIR VALUE	CARRYING VALUE	FAIR VALUE
Long-term debt................................	$90,000	$99,479	$90,000	$98,737

11. SIGNIFICANT CONCENTRATIONS OF RISK

All of our revenues are derived from the transportation of NGLs to various companies in the NGL industry, primarily located in the United States. Although this concentration could affect our overall exposure to credit risk since these customers might be affected by similar economic or other conditions, management believes that the Company is exposed to minimal credit risk, since the majority of our business is conducted with major companies within the industry. We perform periodic credit evaluations of our customers' financial condition and generally do not require collateral for receivables.

REPORT OF INDEPENDENT AUDITORS

The Board of Directors of
Seminole Pipeline Company:

We have audited the accompanying balance sheets of Seminole Pipeline Company as of December 31, 2000 and 2001 and the related accompanying statements of operations, statements of stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Seminole Pipeline Company at December 31, 2000 and 2001 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

ERNST & YOUNG LLP

Tulsa, Oklahoma
March 6, 2002,
except for the matter described in Note 14,
as to which the date is September 6, 2002

SEMINOLE PIPELINE COMPANY

STATEMENTS OF OPERATIONS

(RESTATED) (UNAUDITED) (DOLLARS IN THOUSANDS)

	FOR YEARS ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	1999	2000	2001	2001	2002
REVENUES	$ 64,210	$66,609	$65,800	$30,880	$34,856
COSTS AND EXPENSES					
Operating costs and expenses	27,278	37,293	33,539	16,430	17,315
Selling, general and administrative	1,035	1,700	1,535	750	796
Total	28,313	38,993	35,074	17,180	18,111
OPERATING INCOME	35,897	27,616	30,726	13,700	16,745
OTHER INCOME (EXPENSE)					
Interest expense	(5,002)	(5,003)	(5,160)	(2,450)	(2,006)
Other, net	670	(1,542)	662	(9)	(7)
Total	(4,332)	(6,545)	(4,498)	(2,459)	(2,013)
INCOME BEFORE INCOME TAXES	31,565	21,071	26,228	11,241	14,732
PROVISION FOR INCOME TAXES	(11,611)	(7,590)	(9,470)	(3,837)	(5,347)
NET INCOME	$ 19,954	$13,481	$16,758	$ 7,404	$ 9,385

See Notes to Financial Statements

SEMINOLE PIPELINE COMPANY

BALANCE SHEETS

	DECEMBER 31, 2000	DECEMBER 31, 2001 (RESTATED)	JUNE 30, 2002 (UNAUDITED)
(DOLLARS IN THOUSANDS)			
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents	$ 11,535	$ 16,513	$ 11,160
Accounts receivable -- trade	6,066	10,995	8,791
Accounts receivable -- affiliates	1,582	2,783	7,791
Accounts receivable -- other	117	152	408
Income taxes due from affiliates	--	--	1,637
Prepaid and other current assets	87	35	122
Total current assets	19,388	30,479	29,909
PROPERTY, PLANT AND EQUIPMENT, NET	261,358	251,751	249,390
OTHER ASSETS	194	170	440
TOTAL	$280,940	$282,399	$279,739
LIABILITIES AND STOCKHOLDERS' EQUITY			
CURRENT LIABILITIES			
Current portion of long-term debt	$ 15,000	$ 15,000	$ 15,000
Accounts payable -- trade	4,644	2,646	2,389
Accounts payable -- affiliates	15,437	15,460	17,948
Accrued income taxes due affiliates	54	8,471	--
Accrued taxes, other than income taxes	2,557	2,717	2,665
Other current liabilities	3,265	796	1,853
Total current liabilities	40,957	45,090	39,855
LONG-TERM DEBT	60,000	45,000	45,000
DEFERRED INCOME TAXES	58,858	59,226	59,116
COMMITMENTS AND CONTINGENCIES			
STOCKHOLDERS' EQUITY			
Capital stock:			
Preferred stock, Series A, without par value, $100 stated value; 100 shares authorized and issued; involuntary liquidation preference aggregated $79,170	10	10	10
Common stock, $100 par value; 1,000 shares authorized and issued	100	100	100
Paid-in capital	114,357	114,357	114,357
Retained earnings	6,658	18,616	21,301
Total stockholders' equity	121,125	133,083	135,768
Total	$280,940	$282,399	$279,739

See Notes to Financial Statements

SEMINOLE PIPELINE COMPANY

STATEMENTS OF STOCKHOLDERS' EQUITY

(DOLLARS IN THOUSANDS)	PREFERRED STOCK	COMMON STOCK	PAID-IN CAPITAL	RETAINED EARNINGS	TOTAL
Balance, December 31, 1998	$10	$100	$114,357	$ 28,813	$143,280
Net income	--	--	--	19,954	19,954
Cash dividends paid to stockholders	--	--	--	(24,000)	(24,000)
Balance, December 31, 1999	10	100	114,357	24,767	139,234
Net income (restated)	--	--	--	13,481	13,481
Cash dividends paid to stockholders	--	--	--	(31,590)	(31,590)
Balance, December 31, 2000 (restated)	10	100	114,357	6,658	121,125
Net income (restated)	--	--	--	16,758	16,758
Cash dividends paid to stockholders	--	--	--	(4,800)	(4,800)
Balance, December 31, 2001 (restated)	10	100	114,357	18,616	133,083
Net income (unaudited)	--	--	--	9,385	9,385
Cash dividends paid to stockholders (unaudited)	--	--	--	(6,700)	(6,700)
Balance, June 30, 2002 (unaudited)	$10	$100	$114,357	$ 21,301	$135,768

See Notes to Financial Statements

SEMINOLE PIPELINE COMPANY

STATEMENTS OF CASH FLOWS

(RESTATED)

	FOR YEARS ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	1999	2000	2001	2001	2002
				(UNAUDITED)	
	(DOLLARS IN THOUSANDS)				
OPERATING ACTIVITIES					
Net income	$ 19,954	$ 13,481	$ 16,758	$ 7,404	$ 9,385
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:					
Depreciation and amortization	10,125	10,183	10,199	5,095	5,123
Deferred income taxes	1,199	759	368	374	(110)
Net effect of changes in operating accounts	(12,030)	10,623	(1,982)	(4,504)	(10,302)
Operating activities cash flows	19,248	35,046	25,343	8,369	4,096
INVESTING ACTIVITIES					
Capital expenditures	(1,964)	(810)	(576)	(297)	(2,763)
Proceeds from sale of assets	18	15	11	11	14
Investing activities cash flows	(1,946)	(795)	(565)	(286)	(2,749)
FINANCING ACTIVITIES					
Long-term debt repayments	--	--	(15,000)	--	--
Cash dividends paid to stockholders	(24,000)	(31,590)	(4,800)	(2,000)	(6,700)
Financing activities cash flows	(24,000)	(31,590)	(19,800)	(2,000)	(6,700)
CHANGE IN CASH AND CASH EQUIVALENTS	(6,698)	2,661	4,978	6,083	(5,353)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	15,572	8,874	11,535	11,535	16,513
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 8,874	$ 11,535	$ 16,513	$17,618	$ 11,160

See Notes to Financial Statements

NOTES TO FINANCIAL STATEMENTS
(INFORMATION PERTAINING TO JUNE 30, 2002 AND TO THE
SIX MONTHS ENDED JUNE 30, 2001 AND 2002 IS UNAUDITED)

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Seminole Pipeline Company ("Seminole"), a Delaware corporation, was organized in 1981 for the purpose of constructing and operating a common carrier liquified petroleum products pipeline. Unless the context requires otherwise, references to "we", "us", "our", or the "Company" are intended to mean Seminole Pipeline Company. Seminole's 100 shares of non-voting and non-participating preferred stock and 1,000 shares of common stock are held by Williams Natural Gas Liquids Inc. ("WNGL") (80%), AMOCO Pipeline Seminole Investment Company ("AMOCO") (10%) and Texaco Natural Gas Liquids Inc. ("Texaco") (10%).

Our operations include the transportation, pumping, metering and underground storage of natural gas liquids ("NGLs"), including demethanized mix, ethane-propane mix and specification liquid products. Our primary asset, the Seminole pipeline primarily transports natural gas liquids ("NGLs") from Hobbs, Texas and the Permian Basin to Mont Belvieu, Texas. We have only one operating segment, pipeline transportation.

These financial statements are prepared in accordance with generally accepted accounting principles in the United States. The information contained in these financial statements may differ in some respects from the information filed with the Federal Energy Regulatory Commission ("FERC").

The interim financial data are unaudited; however, in the opinion of management, the interim financial data includes all adjustments, consisting of normal recurring adjustments, necessary for a fair presentation of the results as of June 30, 2002 and for the six-month periods ended June 30, 2001 and 2002. The results of operations for the six months ended June 30, 2002 and 2001 are not necessarily indicative of the results to be expected for the full year.

CASH AND CASH EQUIVALENTS consist of short-term, highly liquid investments that are readily convertible into cash. All investments classified as cash equivalents have maturities at the date of purchase of three months or less. Cash flows are computed using the indirect method.

DOLLAR AMOUNTS (except per share amounts) presented in the tabulations within the notes to our financial statements are stated in thousands of dollars, unless otherwise indicated.

EARNINGS PER SHARE is generally computed by dividing net income by either common stock outstanding (for basic earnings per share) or common and preferred stock outstanding (for diluted earnings per share). We have 1,000 shares of common stock outstanding and 100 shares of preferred stock outstanding during all periods presented within these financial statements. Earnings per share is not presented since the Company is a nonpublic entity that has a simple capital structure and few stockholders. As a result, we believe an earnings per share computation would not be meaningful to users of our financial statements.

ENVIRONMENTAL expenditures that relate to current or future revenues are expensed or capitalized based upon the nature of the expenditures. Expenditures resulting from an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Environmental liabilities are recorded independently of any potential claim for recovery. Receivables are recognized in cases where the realization of reimbursements of remediation costs are considered probable. Accruals related to environmental matters are generally determined based on site-specific plans for remediation, taking into account the prior remediation experience of the Company.

INCOME TAXES are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of the Company's assets and liabilities. For federal income tax reporting, the Company is included in The Williams Companies, Inc. ("Williams") consolidated tax return. The provision for income taxes has been charged to Seminole as if separate income tax returns were filed.

LONG-LIVED ASSETS are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Long-lived assets that are held for disposal are valued at the lower of carrying amount or fair value less cost to sell.

PROPERTY, PLANT AND EQUIPMENT is recorded at cost and is depreciated using the straight-line method over the asset's estimated useful life at annual rates ranging from 2.25% to 25%. Expenditures for maintenance and repairs are charged to operations in the period incurred. The cost of assets retired or sold, together with the related accumulated depreciation, is removed from the accounts, and any gain or loss on disposition is included in income.

REVENUE is based on tariffs charged to customers for pipeline volumes transported. Shippers are invoiced and the related revenue is recorded as deliveries are made.

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. Our actual results could differ from these estimates.

2. RECENTLY ISSUED ACCOUNTING STANDARDS

The Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations" in June 2001. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. This statement is effective for our fiscal year beginning January 1, 2003. We are evaluating the provisions of this statement.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. We adopted this statement effective January 1, 2002 and determined that it did not have any significant impact on our financial statements as of that date.

In April 2002, the FASB issued SFAS No. 145, "Rescission of SFAS Statements No. 4, 44, and 64, Amendment of SFAS No. 13, and Technical Corrections." The purpose of this statement is to update, clarify and simplify existing accounting standards. We adopted this statement effective April 30, 2002 and determined that it did not have any significant impact on our financial statements as of that date.

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. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operation, 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. This statement is effective for our fiscal year beginning January 1, 2003. We are evaluating the provisions of this statement.

3. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consists of the following at the periods indicated:

	DECEMBER 31, 2000	DECEMBER 31, 2001	JUNE 30, 2002 (UNAUDITED)
Pipelines and related equipment	$ 381,010	$ 381,381	$ 384,065
Land	964	964	964
Total	381,974	382,345	385,029
Less accumulated depreciation	(120,616)	(130,594)	(135,639)
Property, plant and equipment, net	$ 261,358	$ 251,751	$ 249,390

Depreciation expense for the years ended December 31, 1999, 2000 and 2001 was $10.1 million, $10.2 million and $10.2 million, respectively. Depreciation expense for each of the six month periods ended June 30, 2001 and 2002 was $5.1 million.

4. LONG-TERM DEBT

In December 1993, we issued $75 million of 6.67% Senior Unsecured Notes in the private placement market. These notes are payable at $15 million annually on December 1 from 2001 through 2005. Interest is paid semi-annually on June 1 and December 1. The Senior Notes agreement contains restrictive covenants, which limit the payment of advances or dividends to stockholders and restrict additional borrowing of funds. Such provisions restricted $90 million of consolidated net worth at December 31, 2001. We were in compliance with these covenants at December 31, 2001.

5. CAPITAL STRUCTURE

In the event of involuntary liquidation or dissolution the Company, the holders of the preferred stock are entitled to be paid an amount equal to the subscription price (stated value of $100 per share) and paid-in capital (contributions less distributions of paid-in capital) before any holders of common stock or any other class of stock receive distributions.

Cash dividends paid to stockholders are calculated each quarter based on the amount of cash flow available. The stockholders receive an amount proportionate to their ownership percentage.

6. INCOME TAXES

The provision for income taxes are as follows for the periods indicated:

	FOR YEARS ENDED DECEMBER 31, 1999	2000	2001
Current:			
Federal	$10,139	$6,473	$8,718
State	273	358	384
	10,412	6,831	9,102
Deferred:			
Federal	1,012	797	334
State	187	(38)	34
Provision for income taxes	$11,611	$7,590	$9,470

Reconciliation from the provision for income taxes at the U.S. federal statutory rate to the effective tax rate for the provision for income taxes are as follows:

	FOR YEARS ENDED DECEMBER 31,		
	1999	2000	2001
Provision at statutory rate	$11,048	$7,375	$9,180
Increases (reductions) in taxes resulting from:			
State income taxes (net of federal benefit)	299	208	272
Other	264	7	18
Provision for income taxes	$11,611	$7,590	$9,470

Significant components of deferred tax liabilities and assets as of December 31, 2000 and 2001 are as follows:

	DECEMBER 31,	
	2000	2001
Deferred tax liabilities:		
Property, plant and equipment	$61,184	$61,729
Total deferred tax liabilities	61,184	61,729
Deferred tax assets:		
Accrued liabilities	2,184	2,361
Other	142	142
Total deferred tax assets	2,326	2,503
Net deferred tax liabilities	$58,858	$59,226

7. RELATED PARTY TRANSACTIONS

Our stockholders or their affiliated companies transport product in our pipeline system. Operating revenues from affiliates for the last three years were as follows:

	FOR YEARS ENDED DECEMBER 31,		
	1999	2000	2001
Revenues from affiliates	$30,477	$32,784	$33,006
Revenues from affiliates as a percentage of total revenues	47%	49%	50%

At December 31, 2000 and 2001, we owed $8.5 million and $14.3 million respectively, to Mid-America Pipeline Company ("MAPL"), a wholly-owned subsidiary of WNGL, primarily for its share of the joint tariff on movements originating in MAPL's pipeline system. MAPL is paid for its share of the joint tariff following delivery of the NGLs to destinations on our system.

In addition, MAPL employees provide pipeline management services to us pursuant to a service agreement. MAPL charged us $1.0 million, $1.2 million and $1.2 million for such services during 1999, 2000 and 2001, respectively. We lease land under an operating lease from an affiliate of AMOCO. Operating lease expense related to this arrangement was approximately $0.1 million for each of the years 1999, 2000 and 2001. The fee is adjusted annually in accordance with the Gross National Product price deflator. The original term of the lease was fifteen years, beginning August 1, 1981, with a renewal option for three consecutive five-year periods. The lease was renewed on August 1, 1996 and August 1, 2001. Future minimum payments for this lease are as follows:

2002	$140
2003	143
2004	148
2005	151
2006	106
Total minimum obligations	$688

8. MAJOR CUSTOMERS

One non-affiliated shipper accounted for 17%, 15% and 15% of operating revenues for the years ended 1999, 2000 and 2001, respectively.

9. COMMITMENTS AND CONTINGENCIES

LEASE COMMITMENTS

We lease land from an affiliate of AMOCO under an operating lease agreement. See Note 7 for a description of this arrangement.

LITIGATION

On August 10, 1999, a subcontractor installing utility poles for a local electric utility struck our pipeline. The accident resulted in the death of one of the subcontractor's employees, destroyed the subcontractor's equipment and burned the vegetation on nearby lots. During January 2000, the decedent's family filed suit against us, the subcontractor and the local electric utility. We recorded an estimate for the settlement in 2000. Settlement was reached with the decedent's family during February 2001 for $2.3 million. The payment was made March 9, 2001. The remaining liability of $79,000 is included in other current liabilities at December 31, 2001, which is to cover remaining legal expenses.

In addition to the foregoing, various proceedings are pending against the Company incidental to our operations. Management believes the ultimate resolution of these matters will not have a material adverse effect upon our future financial position, results of operations or cash flow requirements.

10. SUPPLEMENTAL CASH FLOWS DISCLOSURE

	FOR YEARS ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	1999	2000	2001	2001	2002
				(UNAUDITED)	
(Increase) decrease in:					
Accounts receivable	$(6,760)	$ 8,222	$(6,165)	$(2,526)	$(3,060)
Income taxes due from affiliates	--	--	--	--	(1,637)
Prepaid and other current assets	115	(22)	52	(175)	(87)
Other assets	32	1	(2)	26	(283)
Increase (decrease) in:					
Accounts payable	(351)	10,678	(1,975)	(4,500)	2,231
Accrued taxes	2,317	(10,324)	8,577	4,783	(8,523)
Other current liabilities	(7,350)	2,068	(2,469)	(2,112)	1,057
Other liabilities	(33)	--	--	--	--
Net effect of changes in operating accounts	$(12,030)	$ 10,623	$(1,982)	$(4,504)	

$(10,302) ======== ======== =======
======= ========

Income taxes paid were $9.3 million, $7.5 million and $10.3 million for the year ended December 31, 1999, 2000 and 2001, respectively, and $5.2 million for the six months ended June 30, 2002. No income taxes were paid during the six months ended June 30, 2001. Interest paid was $5.0 million, $5.1 million and $4.8 million for 1999, 2000 and 2001, respectively, and $2.5 million and $2.1 million for the six months ended June 30, 2001 and 2002, respectively.

11. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following disclosure of estimated fair value was determined by us, using available market information and appropriate valuation methodologies. Considerable judgment, however, is necessary to interpret market data and develop the related estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize upon disposition of the financial instruments. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

Cash and cash equivalents. The carrying values reported in the balance sheets for cash and cash equivalents approximate their fair value.

Long-term debt. Debt consists of a private placement of 6.67% Senior Notes. The fair value of private debt is valued based on the prices of similar securities with similar terms and credit ratings.

The carrying amounts and fair values for our financial instruments at December 31, 2000 and 2001 are as follows:

	2000		2001	
	CARRYING VALUE	FAIR VALUE	CARRYING VALUE	FAIR VALUE
Long-term debt................................	$75,000	$74,634	$60,000	$60,300

12. SIGNIFICANT CONCENTRATIONS OF RISK

All of our revenues are derived from the transportation of NGLs to various companies in the NGL industry, primarily located in the United States. Although this concentration could affect our overall exposure to credit risk since these customers might be affected by similar economic or other conditions, management believes that the Company is exposed to minimal credit risk, since the majority of our business is conducted with major companies within the industry. We perform periodic credit evaluations of our customers' financial condition and generally do not require collateral for receivables.

13. SUBSEQUENT EVENTS (UNAUDITED)

On July 31, 2002, WNGL contributed its 80% equity interest in the Company to a newly-formed affiliate of Williams, E-Oaktree, LLC. This contribution was done as part of a subsequent transaction which took place between Williams and Enterprise Products Operating L.P. ("EPOLP") on the same date, whereby EPOLP purchased a 98% equity interest in E-Oaktree, LLC.

14. RESTATEMENT OF FINANCIAL STATEMENTS

In June 2002, the Company discovered an error in the way their revenue system was calculating joint tariff revenue. The impact of this error to revenues and net income was a decrease of $2.9 million and $1.8 million for the year ended December 31, 2000, respectively, and a decrease of $4.3 million and $2.8 million for the year ended December 31, 2001, respectively. The correction of these errors has been reflected in the accompanying restated financial statements.

PROSPECTUS

[ENTERPRISE PRODUCTS PARTNERS L.P. LOGO]

ENTERPRISE PRODUCTS PARTNERS L.P.

$500,000,000

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

COMMON UNITS

DEBT SECURITIES

We may offer the following securities under this Prospectus:

- Common Units representing limited partner interests in Enterprise Products Partners L.P., and

- Debt Securities of Enterprise Products Operating L.P., which will be guaranteed by its parent company, Enterprise Products Partners L.P.

This Prospectus provides you with a general description of the securities we may offer. Each time we sell securities we will provide a Prospectus Supplement that will contain specific information about the terms of that offering. The Prospectus Supplement may also add, update or change information contained in this prospectus. You should read this Prospectus and any Prospectus Supplement carefully before you invest.

In addition, Common Units may be offered from time to time by other holders thereof. Any selling unitholders will be identified, and the number of Common Units to be offered by them will be specified, in a Prospectus Supplement to this Prospectus. We will not receive proceeds of any sale of shares by any such selling unitholders.

The Common Units are listed on the New York Stock Exchange under the trading symbol "EPD." Any Common Units sold pursuant to a Prospectus Supplement will be listed on that exchange, subject to official notice of issuance. On March 20, 2001, the closing price of a Common Unit on that exchange was $34.98.

Unless otherwise specified in a Prospectus Supplement, the senior debt securities, when issued, will be unsecured and will rank equally with our other unsecured and unsubordinated indebtedness. The subordinated debt securities, when issued, will be subordinated in right of payment to our senior debt.

YOU SHOULD CAREFULLY REVIEW "RISK FACTORS" BEGINNING ON PAGE 3 FOR A DISCUSSION OF THINGS YOU SHOULD CONSIDER WHEN INVESTING IN OUR SECURITIES.

NEITHER THE SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THESE SECURITIES OR PASSED UPON THE ADEQUACY OR ACCURACY OF THIS PROSPECTUS. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

This Prospectus may not be used to consummate sales of securities unless accompanied by a Prospectus Supplement.

The date of this Prospectus is March 27, 2001.

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FORWARD-LOOKING STATEMENTS

The statements in this Prospectus and the documents incorporated by reference that are not historical facts are forward-looking statements. We have based these forward-looking statements on our current expectations and projections about future events based upon our knowledge of facts as of the date of this Prospectus and our assumptions about future events. Although we believe that the expectations reflected in these forward-looking statements are reasonable, we can give no assurance that these expectations will prove to be correct. These statements are subject to certain risks, uncertainties, and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions provide incorrect, actual results may vary materially from those anticipated, estimated, projected, or expected. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- competitive practices in the industries in which we compete,

- fluctuations in oil, natural gas, and NGL product prices and production,

- operational and systems risks,

- environmental liabilities that are not covered by indemnity or insurance,

- the impact of current and future laws and governmental regulations (including environmental regulations) affecting the NGL industry in general, and our operations in particular,

- loss of a significant customer, and

- failure to complete one or more new projects on time or within budget.

We use words like "anticipate," "estimate," "project," "expect," "plan," "forecast," "intend," "could," and "may," and similar expressions and statements regarding our business strategy, plans and objectives for future operations to help identify forward-looking statements. We have no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

WHERE YOU CAN FIND MORE INFORMATION

Enterprise Products Partners L.P. and Enterprise Products Operating L.P. file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission. You may read and copy any document we file at the Commission's public reference rooms in Washington, D.C., New York, New York and Chicago, Illinois. Please call the Commission at (800) SEC-0330 for further information on the public reference rooms. Our filings are also available to the public at the Commission's web site at http://www.sec.gov. In addition, documents filed by us can be inspected at the offices of the New York Stock Exchange, Inc. 20 Broad Street, New York, New York 10002.

INCORPORATION OF CERTAIN DOCUMENTS BY REFERENCE

The Commission allows us to "incorporate by reference" into this Prospectus the information we file with it, which means that we can disclose important information to you by referring you to those documents. The information incorporated by reference is considered to be part of this Prospectus, and later information that we file with the Commission will automatically update and supersede this information. We incorporate by reference the documents listed below filed by Enterprise Products Partners L.P. or Enterprise Products Operating L.P. and any future filings made by either company with the Commission under section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 until our offering is completed:

(1) Annual Report on Form 10-K for the fiscal year ended December 31, 2000;

(2) Current Reports on Form 8-K filed with the Commission on January 25, 2001 and February 2, 2001; and

(3) The description of the common units contained in the Registration Statement on Form 8-A, initially filed with the Commission on July 21, 1998, and any subsequent amendment thereto filed for the purposes of updating such description.

We will provide without charge to each person, including any beneficial owner, to whom this Prospectus is delivered, upon written or oral request, a copy of any document incorporated by reference in this Prospectus, other than exhibits to any such document not specifically described above. Requests for such documents should be directed to Investor Relations, Enterprise Products Partners L.P., 2727 North Loop West, Suite 700, Houston, Texas 77008-1038; telephone number: (713) 880-2724.

THE COMPANY

Enterprise Products Partners L.P. (the "Company") is a publicly traded master limited partnership that was formed in April 1998 to acquire, own, and operate all of the NGL processing and distribution assets of Enterprise Products Company. We conduct all of our business through our 99% owned subsidiary, Enterprise Products Operating L.P. (the "Operating Partnership") and its subsidiaries and joint ventures. Enterprise Products GP, LLC (the "General Partner") is the general partner of the Company and the Operating Partnership, owning 1.0% and 1.0101% equity interests, respectively, in those partnerships.

We are a leading integrated North American provider of processing and transportation services to domestic producers of natural gas, domestic and foreign producers of natural gas liquids ("NGLs") and other liquid hydrocarbons and domestic and foreign consumers of NGL and liquid hydrocarbon products. We manage a fully integrated and diversified portfolio of midstream energy assets. We own and operate:

- natural gas processing plants;

- NGL fractionation facilities;

- storage facilities;

- pipelines;

- propylene production facilities;

- rail transportation facilities; and

- a methyl tertiary butyl ether ("MTBE") production facility.

Certain of these facilities are owned jointly by us and other industry partners, either through co-ownership arrangements or joint ventures. Some of these jointly owned facilities are operated by other owners.

Our principal executive office is located at 2727 North Loop West, Houston, Texas 77008-1038, and our telephone number is (713) 880-6500.

RECENT SIGNIFICANT DEVELOPMENTS

Manta Ray, Nautilus and Nemo Pipeline Systems. On January 29, 2001, we acquired ownership interests in three natural gas pipeline systems and related equipment located offshore Louisiana in the Gulf of Mexico from affiliates of El Paso Energy Corp. for approximately $88 million in cash. These systems total approximately 360 miles of pipeline. We acquired a 25.67% interest in each of the Manta Ray and Nautilus pipeline systems and a 33.92% interest in the Nemo pipeline system. Affiliates of Shell Oil Company own an interest in all three systems, and an affiliate of Marathon Oil Company owns an interest in the Manta Ray and Nautilus systems. The Manta Ray system comprises approximately 237 miles of pipeline with a capacity of 750 million cubic fee ("MMcf") per day and related equipment, the Nautilus system comprises approximately 101 miles of pipeline with a capacity of 600 MMcf per day, and the Nemo system, when completed in the fourth quarter of 2001, will comprise approximately 24 miles of pipeline with a capacity of 300 MMcf per day.

Stingray Pipeline System and Related Facilities. On January 29, 2001, we and an affiliate of Shell acquired, through a 50/50 owned entity, the Stingray natural gas pipeline system and related facilities from an affiliate of El Paso for approximately $50 million in cash. The Stingray system comprises approximately 375 miles of pipeline with a capacity of 1.2 billion cubic feet ("Bcf") per day offshore Louisiana in the Gulf of Mexico. Shell will be responsible for the commercial and physical operations of the Stingray system.

Acadian Gas LLC. On September 25, 2000, we announced that we had executed a definitive agreement to acquire Acadian Gas, LLC ("Acadian Gas") from an affiliate of Shell for $226 million in cash, inclusive of working capital. Acadian Gas' assets are comprised of the 438-mile Acadian, 577-mile Cypress and 27-mile Evangeline natural gas pipeline systems, which together have over one Bcf per day of capacity. The system includes a leased natural gas storage facility at Napoleonville, Louisiana. The Acadian Gas system, located in South Louisiana, will integrate with our Gulf Coast natural gas processing and NGL fractionation, pipeline and storage system. We expect to close the acquisition in the first quarter of 2001.

Lou-Tex NGL Pipeline. In November 2000, we completed construction of a wholly-owned, 206-mile, 12" NGL pipeline from Breaux Bridge, Louisiana to Mont Belvieu, Texas. The Lou-Tex NGL pipeline transports mixed NGLs, NGL products and mixed propane/propylene streams between major markets in Louisiana and Texas.

RISK FACTORS

An investment in the securities involves a significant degree of risk, including the risks described below. You should carefully consider the following risk factors and the other information in this Prospectus before deciding to invest in the securities. The risks described below are not the only ones facing us. This Prospectus also contains forward-looking statements that involve risks and uncertainties. See "Forward-Looking Statements." Our actual results could differ materially from those anticipated in the forward-looking statements as a result of certain factors, including the risks described below and elsewhere in this Prospectus.

RISKS INHERENT IN OUR BUSINESS

THE PROFITABILITY OF OUR OPERATIONS DEPENDS UPON THE SPREAD BETWEEN NATURAL GAS PRICES AND NGL.

Prices for 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. 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;

- conservation and the extent of governmental regulation of production and the overall economic environment.

A decrease in the difference between natural gas and NGL prices results in lower margins on volumes processed.

THE PROFITABILITY OF OUR OPERATIONS DEPENDS UPON THE DEMAND AND PRICES FOR OUR PRODUCTS AND SERVICES.

The products that we process 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 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.

Ethane. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically separated from the natural gas stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas producers to leave the ethane in the natural gas stream to be burned as fuel than to extract the ethane from the mixed NGL stream for sale as an ethylene feedstock thereby reducing the volume of NGLs for fractionation.

Propane. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating, engine and industrial fuel. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is at its highest during the six-month peak heating season of October through March.

Isobutane. Isobutane is predominantly used in refineries to produce alkylates to enhance octane levels and in the production of MTBE, which is used in motor gasoline. Accordingly, any action that reduces demand for motor gasoline in general or MTBE in particular would similarly reduce demand for isobutane. Further, we purchase a portion of the normal butane feedstock that we convert into isobutane for our merchant customers in the spot and import markets. On those occasions where the pricing differential between isobutane and normal butane (i.e., the "isobutane spread") is narrow, we may find it more economical to purchase isobutane on the spot market for delivery to customers than to process the normal butane in our inventory. We frequently retain the normal butane in our inventory until pricing differentials improve or until product prices increase. However, if the price of normal butane declines, our inventory may decline in value. During periods in which isobutane spreads are narrow or inventory values are high relative to current prices for normal butane or isobutane, our operating margin from selling isobutane will be reduced.

MTBE. The production of MTBE is driven by oxygenated fuels programs enacted under the federal Clean Air Amendments of 1990 and other legislation. Any changes to these 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. On March 25, 1999, the Governor of California ordered the phase-out of MTBE in California by the end of 2002 due to 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. In addition, legislation to amend the federal Clean Air Act has been introduced in the U.S. House of Representatives to ban the use of MTBE as a fuel additive within three years. Legislation introduced in the U.S. Senate would eliminate the Clean Air Act's oxygenate requirement in order to foster the elimination of MTBE in fuel. No assurance can be given as to whether this or similar legislation ultimately will be adopted or whether the U.S. Congress or the EPA might take steps to override the MTBE ban in California.

Propylene. Propylene is sold to petrochemical companies for a variety of uses, principally for the production of polypropylene. Propylene is subject to rapid and material price fluctuations. Any downturn in the domestic or international economy could cause reduced demand for, and result in an oversupply of, propylene, which could cause a reduction in the volumes of propylene that we produce and expose our investment in inventories of propane/propylene mix to pricing risk due to requirements for short-term price discounts in the spot or short-term propylene markets.

THE PROFITABILITY OF OUR OPERATIONS DEPENDS UPON THE AVAILABILITY OF A SUPPLY OF NGL FEEDSTOCK.

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.

WE DEPEND ON CERTAIN KEY CUSTOMERS AND CONTRACTS.

We currently derive a significant portion of our revenues from contracts with certain key customers. The loss of these or other significant customers could adversely affect our results of operations. Lyondell Worldwide accounted for approximately 43.2% of our isomerization volumes in 2000. Our current contract with Lyondell has a ten-year term which expires in December 2009. Our unconsolidated affiliate, Belvieu Environmental Fuels ("BEF"), has an agreement with Sunoco pursuant to which Sunoco is required to purchase all of BEF's MTBE production through September 2004. Our contract for sales of high purity propylene to Basell accounted for approximately 36.4% of 2000 production. We are a party to a natural gas processing contract with Shell and certain of its affiliates which provides us with the right to process substantially all natural gas produced from the Shell entities' Gulf of Mexico properties for the next 20 years.

WE EXPERIENCE SIGNIFICANT COMPETITION.

We face competition from oil, natural gas, natural gas processing and petrochemical companies. The principal areas of competition include obtaining gas supplies for processing operations, obtaining supplies of raw product for fractionation and the marketing and transportation of natural gas liquids. Competition typically arises as a result of the location and operating efficiency of facilities, the reliability of services and price and delivery capabilities. Our NGL fractionation facilities at Mont Belvieu compete for volumes of mixed NGLs with three other fractionators at Mont Belvieu. In addition, certain major producers fractionate NGLs for their own account in captive facilities. The Mont Belvieu fractionation facilities also compete on a more limited basis with two fractionators in Conway, Kansas. We also compete with large, integrated energy and petrochemical companies in our isomerization, MTBE, propylene and natural gas processing businesses. Our customers who are significant producers or consumers of NGLs or natural gas may develop their own processing facilities in lieu of using our services or co-investing with us in new projects. In addition, certain of our competitors may have advantages in competing for acquisitions or other new business opportunities because of their financial resources and access to NGL supplies.

WE ARE SUBJECT TO OPERATING AND LITIGATION RISKS WHICH MAY NOT BE COVERED BY INSURANCE.

Our operations are subject to all operating hazards and risks normally incidental to processing, storing and transporting, and otherwise providing for use by third parties, natural gas, NGLs, propane/propylene mix and MTBE. As a result, we may be a defendant in various legal proceedings and litigation arising in the ordinary course of business. We cannot assure you that the insurance we maintain will be adequate to protect us from all material expenses related to potential future claims for personal and property damage.

OUR BUSINESSES ARE SUBJECT TO GOVERNMENTAL REGULATION WITH RESPECT TO ENVIRONMENTAL, SAFETY AND OTHER REGULATORY MATTERS.

Our business is subject to the jurisdiction of governmental agencies with respect to a wide range of environmental, safety and other regulatory matters. We could be adversely affected by increased costs due to more strict pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental regulations might adversely impact our products and activities, including processing, storage and transportation. Federal and state agencies also could impose additional safety requirements, any of which could affect profitability. In addition, there are risks of accidental releases or spills associated with our operations, and we cannot assure you that material costs and liabilities will not be incurred, including those relating to claims for damages to property and persons.

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 the operations of our pipelines and processing and storage facilities. For example, our Mont Belvieu processing and storage facility is 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 nine areas in the country in this "severe" category. Another consequence of this non-attainment status and efforts to eliminate it is the potential imposition of lower limits on the emissions of certain pollutants, particularly oxides of nitrogen which are produced through combustion, as in the gas turbines at the Mont Belvieu processing facility. Regulations to achieve attainment status and imposing new requirements on existing facilities in the Houston-Galveston area were issued by the Texas Natural Resource Conservation Commission in December, 2000. These regulations mandate 90% reductions in oxides of nitrogen emissions from point sources, such as the gas turbines at our Mont Belvieu processing facility. The technical practicality and economic reasonableness of requiring existing gas turbines to achieve such reductions, as well as the substantive basis for setting the 90% reduction requirements, have been challenged under state law in a suit we filed as part of a coalition of major Houston-Galveston area industries. If these regulations stand as issued, they would require substantial redesign and modification of these facilities to achieve the mandated reductions; however, the precise impact of these requirements on our operations cannot be determined until this litigation is resolved.

WE DEPEND UPON OUR KEY PERSONNEL.

We believe that our success has been dependent to a significant extent upon the efforts and abilities of our senior management team and in particular Dan

Duncan, Chairman of the Board (age 68) and O. S. Andras, President and Chief Executive Officer (age 65). The simultaneous deaths or retirement of Mr. Duncan and Mr. Andras could have an adverse impact on our operations. However, in recent years we have added to the key members of our senior management team, thereby reducing the potential consequences that could result from losing the services of both Mr. Duncan and Mr. Andras within a short time. We do not maintain any life insurance for these persons.

RISKS INHERENT IN AN INVESTMENT IN THE SECURITIES

The prospectus supplement accompanying this prospectus will describe any additional risk factors inherent in an investment in the particular securities being offering.

USE OF PROCEEDS

Except as may be set forth in a prospectus supplement, we will use the net proceeds from any sale of securities described in this prospectus for future business acquisitions and other general corporate purposes, such as working capital, investments in subsidiaries, the retirement of existing debt and/or the repurchase of common units or other securities. The exact amounts to be used and when the net proceeds will be applied to corporate purposes will depend on a number of factors, including our funding requirements and the availability of alternative funding sources. We routinely review acquisition opportunities. A prospectus supplement will disclose any future proposal to use net proceeds from an offering of our securities to finance any specific acquisition, if applicable.

We will not receive any proceeds from any sale of common units by any selling unitholders.

RATIO OF EARNINGS TO FIXED CHARGES

The ratios of earnings to fixed charges for each of the periods indicated are as follows:

	YEAR ENDED DECEMBER 31,				
COMPANY	1996	1997	1998	1999	2000
Enterprise Products Partners L.P.	2.38	2.11	1.16	5.84	6.41
Enterprise Products Operating L.P.	2.40	2.17	1.16	5.90	6.47

These computations include us and our subsidiaries, and 50% or less equity companies. For these ratios, "earnings" is the amount resulting from adding and subtracting the following items.

Add the following:

- pre-tax income from continuing operations before adjustment for minority interests in consolidated subsidiaries or income or loss from equity investees;

- fixed charges;

- amortization of capitalized interest;

- distributed income of equity investees; and

- our share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges.

From the total of the added items, subtract the following:

- interest capitalized;

- preference security dividend requirements of consolidated subsidiaries; and

- minority interest in pre-tax income of subsidiaries that have not incurred fixed charges.

The term "fixed charges" means the sum of the following:

- interest expensed and capitalized;

- amortized premiums, discounts and capitalized expenses related to indebtedness;

- an estimate of the interest within rental expenses (equal to one-third of rental expense); and

- preference security dividend requirements of consolidated subsidiaries.

DESCRIPTION OF DEBT SECURITIES

The debt securities will be issued under an Indenture dated as of March 15, 2000 (the "Indenture"), among the Operating Partnership, as issuer, the Company, as guarantor, and First Union National Bank, as trustee (the "Trustee").

The terms of the debt securities will include those expressly set forth in the Indenture and those made part of the Indenture by reference to the Trust Indenture Act of 1939, as amended (the "Trust Indenture Act"). Capitalized terms used in this Description of Debt Securities have the meanings specified in the Indenture.

This Description of Debt Securities is intended to be a useful overview of the material provisions of the debt securities and the Indenture. Since this Description of Debt Securities is only a summary, you should refer to the Indenture for a complete description of our obligations and your rights.

References to the "Issuer" mean only Enterprise Products Operating L.P. and not its subsidiaries. References to the "Guarantor" mean only Enterprise Products Partners L.P. and not its subsidiaries. References to "we" and "us" mean the Issuer and the Guarantor collectively.

GENERAL

The Indenture does not limit the amount of debt securities that may be issued thereunder. Debt securities may be issued under the Indenture from time to time in separate series, each up to the aggregate amount authorized for such series. The debt securities will be general obligations of the Issuer and the Guarantor and may be subordinated to Senior Indebtedness of the Issuer and the Guarantor. See "Description of Debt Securities -- Subordination."

A prospectus supplement and a supplemental indenture (or a resolution of our Board of Directors and accompanying officers' certificate) relating to any series of debt securities being offered will include specific terms relating to the offering. These terms will include some or all of the following:

- the form and title of the debt securities;

- the total principal amount of the debt securities;

- the portion of the principal amount which will be payable if the maturity of the debt securities is accelerated;

- the currency or currency unit in which the debt securities will be paid, if not U.S. dollars;

- any right we may have to defer payments of interest by extending the dates payments are due whether interest on those deferred amounts will be payable as well;

- the dates on which the principal of the debt securities will be payable;

- the interest rate which the debt securities will bear and the interest payment dates for the debt securities;

- any optional redemption provisions;

- any sinking fund or other provisions that would obligate us to repurchase or otherwise redeem the debt securities;

- any changes to or additional Events of Default or covenants;

- whether the debt securities are to be issued as Registered Securities or Bearer Securities or both; and any special provisions for Bearer Securities;

- the subordination, if any, of the debt securities and any changes to the subordination provisions of the Indenture; and

- any other terms of the debt securities.

The prospectus supplement will also describe any material United States federal income tax consequences or other special considerations applicable to the applicable series of debt securities, including those applicable to:

- Bearer Securities,

- debt securities with respect to which payments of principal, premium or interest are determined with reference to an index or formula, including changes in prices of particular securities, currencies or commodities,

- debt securities with respect to which principal, premium or interest is payable in a foreign or composite currency,

- debt securities that are issued at a discount below their stated principal amount, bearing no interest or interest at a rate that at the time of issuance is below market rates, and

- variable rate debt securities that are exchangeable for fixed rate debt securities.

At our option, we may make interest payments, by check mailed to the registered holders thereof or, if so stated in the applicable prospectus supplement, at the option of a holder by wire transfer to an account designated by the holder. Except as otherwise provided in the applicable prospectus supplement, no payment on a Bearer Security will be made by mail to an address in the United States or by wire transfer to an account in the United States.

Unless otherwise provided in the applicable prospectus supplement, Registered Securities may be transferred or exchanged at the office of the Trustee at which its corporate trust business is principally administered in the United States or at the office of the Trustee or the Trustee's agent in New York City, subject to the limitations provided in the Indenture, without the payment of any service charge, other than any applicable tax or governmental charge. Bearer Securities will be transferable only by delivery. Provisions with respect to the exchange of Bearer Securities will be described in the applicable prospectus supplement.

Any funds we pay to a paying agent for the payment of amounts due on any debt securities that remain unclaimed for two years will be returned to us, and the holders of the debt securities must thereafter look only to us for payment thereof.

GUARANTEE

The Guarantor will unconditionally guarantee to each holder and the Trustee the full and prompt payment of principal of, premium, if any, and interest on the debt securities, when and as the same become due and payable, whether at maturity, upon redemption or repurchase, by declaration of acceleration or otherwise.

CERTAIN COVENANTS

Except as set forth below or as may be provided in a prospectus supplement and supplemental indenture, neither the Issuer nor the Guarantor will be restricted by the Indenture from incurring any type of indebtedness or other obligation, from paying dividends or making distributions on its partnership interests or capital stock or purchasing or redeeming its partnership interests or capital stock. The Indenture will not require the maintenance of any financial ratios or specified levels of net worth or liquidity. In addition, the Indenture will not contain any provisions that would require the Issuer to repurchase or redeem or otherwise modify the terms of any of the debt securities upon a change in control or other events involving the Issuer which may adversely affect the creditworthiness of the debt securities.

Limitations on Liens. The Indenture will provide that the Guarantor will not, nor will it permit any Subsidiary to, create, assume, incur or suffer to exist any mortgage, lien, security interest, pledge, charge or other encumbrance ("liens") other than Permitted Liens (as defined below) upon any Principal Property (as defined below) or upon any shares of capital stock of any Subsidiary owning or leasing any Principal Property, whether owned or leased on the date of the Indenture or thereafter acquired, to secure any indebtedness for borrowed money ("debt") of the Guarantor or the Issuer or any other person (other than the debt securities), without in any such case making effective provision whereby all of the debt securities outstanding shall be secured equally and ratably with, or prior to, such debt so long as such debt shall be so secured. "Principal Property" means, whether owned or leased on the date of the Indenture or thereafter acquired:

(1) any pipeline assets of the Guarantor or any Subsidiary, including any related facilities employed in the transportation, distribution, storage or marketing of refined petroleum products, natural gas liquids, and petrochemicals, that are located in the United States of America or any territory or political subdivision thereof; and

(2) any processing or manufacturing plant or terminal owned or leased by the Guarantor or any Subsidiary that is located in the United States or any territory or political subdivision thereof,

except, in the case of either of the foregoing clauses (1) or (2):

(a) any such assets consisting of inventories, furniture, office fixtures and equipment (including data processing equipment), vehicles and equipment used on, or useful with, vehicles; and

(b) any such assets, plant or terminal which, in the opinion of the board of directors of the General Partner, is not material in relation to the activities of the Issuer or of the Guarantor and its Subsidiaries taken as a whole.

Notwithstanding the foregoing, under the Indenture, the Guarantor may, and may permit any Subsidiary to, create, assume, incur, or suffer to exist any lien upon any Principal Property to secure debt of the Guarantor or any other person (other than the debt securities) other than a Permitted Lien without securing the debt securities, provided that the aggregate principal amount of all debt then outstanding secured by such lien and all similar liens, together with all Attributable Indebtedness from Sale-Leaseback Transactions (excluding Sale-Leaseback Transactions permitted by clauses (1) through (4), inclusive, of the first paragraph of the restriction on sale-leasebacks covenant described below) does not exceed 10% of Consolidated Net Tangible Assets.

"Permitted Liens" means:

(1) liens upon rights-of-way for pipeline purposes;

(2) any statutory or governmental lien or lien arising by operation of law, or any mechanics', repairmen's, materialmen's, suppliers', carriers', landlords', warehousemen's or similar lien incurred in the ordinary course of business which is not yet due or which is being contested in good faith by appropriate proceedings and any undetermined lien which is incidental to construction, development, improvement or repair; or any right reserved to, or vested in, any municipality or public authority by the terms of any right, power, franchise, grant, license, permit or by any provision of law, to purchase or recapture or to designate a purchaser of, any property;

(3) liens for taxes and assessments which are (a) for the then current year, (b) not at the time delinquent, or (c) delinquent but the validity or amount of which is being contested at the time by the Guarantor or any Subsidiary in good faith by appropriate proceedings;

(4) liens of, or to secure performance of, leases, other than capital leases; or any lien securing industrial development, pollution control or similar revenue bonds;

(5) any lien upon property or assets acquired or sold by the Guarantor or any Subsidiary resulting from the exercise of any rights arising out of defaults on receivables;

(6) any lien in favor of the Guarantor or any Subsidiary; or any lien upon any property or assets of the Guarantor or any Subsidiary in existence on the date of the execution and delivery of the Indenture;

(7) any lien in favor of the United States of America or any state thereof, or any department, agency or instrumentality or political subdivision of the United States of America or any state thereof, to secure partial, progress, advance, or other payments pursuant to any contract or statute, or any debt incurred by the Issuer or any Subsidiary for the purpose of financing all or any part of the purchase price of, or the cost of constructing, developing, repairing or improving, the property or assets subject to such lien;

(8) any lien incurred in the ordinary course of business in connection with workmen's compensation, unemployment insurance, temporary disability, social security, retiree health or similar laws or regulations or to secure obligations imposed by statute or governmental regulations;

(9) liens in favor of any person to secure obligations under provisions of any letters of credit, bank guarantees, bonds or surety obligations required or requested by any governmental authority in connection with any contract or statute; or any lien upon or deposits of any assets to secure performance of bids, trade contracts, leases or statutory obligations;

(10) any lien upon any property or assets created at the time of acquisition of such property or assets by the Guarantor or any Subsidiary or within one year after such time to secure all or a portion of the purchase price for such property or assets or debt incurred to finance such purchase price, whether such debt was incurred prior to, at the time of or within one year after the date of such acquisition; or any lien upon any property or assets to secure all or part of the cost of construction, development, repair or improvements thereon or to secure debt incurred prior to, at the time of, or within one year after completion of such construction, development, repair or improvements or the commencement of

full operations thereof (whichever is later), to provide funds for any such purpose;

(11) any lien upon any property or assets existing thereon at the time of the acquisition thereof by the Guarantor or any Subsidiary and any lien upon any property or assets of a person existing thereon at the time such person becomes a Subsidiary by acquisition, merger or otherwise; provided that, in each case, such lien only encumbers the property or assets so acquired or owned by such person at the time such person becomes a Subsidiary;

(12) liens imposed by law or order as a result of any proceeding before any court or regulatory body that is being contested in good faith, and liens which secure a judgment or other court-ordered award or settlement as to which the Guarantor or the applicable Subsidiary has not exhausted its appellate rights;

(13) any extension, renewal, refinancing, refunding or replacement (or successive extensions, renewals, refinancing, refunding or replacements) of liens, in whole or in part, referred to in clauses (1) through (12) above; provided, however, that any such extension, renewal, refinancing, refunding or replacement lien shall be limited to the property or assets covered by the lien extended, renewed, refinanced, refunded or replaced and that the obligations secured by any such extension, renewal, refinancing, refunding or replacement lien shall be in an amount not greater than the amount of the obligations secured by the lien extended, renewed, refinanced, refunded or replaced and any expenses of the Guarantor and its Subsidiaries (including any premium) incurred in connection with such extension, renewal, refinancing, refunding or replacement; or

(14) any lien resulting from the deposit of moneys or evidence of indebtedness in trust for the purpose of defeasing debt of the Guarantor or any Subsidiary.

"Consolidated Net Tangible Assets" means, at any date of determination, the total amount of assets after deducting therefrom:

(1) all current liabilities (excluding (A) any current liabilities that by their terms are extendable or renewable at the option of the obligor thereon to a time more than 12 months after the time as of which the amount thereof is being computed, and (B) current maturities of long-term debt); and

(2) the value (net of any applicable reserves) of all goodwill, trade names, trademarks, patents and other like intangible assets, all as set forth, or on a pro forma basis would be set forth, on the consolidated balance sheet of the Guarantor and its consolidated subsidiaries for the Guarantor's most recently completed fiscal quarter, prepared in accordance with generally accepted accounting principles.

Restriction on Sale-Leasebacks. The Indenture will provide that the Guarantor will not, and will not permit any Subsidiary to, engage in the sale or transfer by the Guarantor or any Subsidiary of any Principal Property to a person (other than the Issuer or a Subsidiary) and the taking back by the Guarantor or any Subsidiary, as the case may be, of a lease of such Principal Property (a "Sale-Leaseback Transaction"), unless:

(1) such Sale-Leaseback Transaction occurs within one year from the date of completion of the acquisition of the Principal Property subject thereto or the date of the completion of construction, development or substantial repair or improvement, or commencement of full operations on such Principal Property, whichever is later;

(2) the Sale-Leaseback Transaction involves a lease for a period, including renewals, of not more than three years;

(3) the Guarantor or such Subsidiary would be entitled to incur debt secured by a lien on the Principal Property subject thereto in a principal amount equal to or exceeding the Attributable Indebtedness from such Sale-Leaseback Transaction without equally and ratably securing the debt securities; or

(4) the Guarantor or such Subsidiary, within a one-year period after such Sale-Leaseback Transaction, applies or causes to be applied an amount not less than the Attributable Indebtedness from such Sale-Leaseback Transaction to (a) the prepayment, repayment, redemption, reduction or retirement of any debt of the Guarantor or any Subsidiary that is not subordinated to the debt securities, or (b) the expenditure or expenditures for Principal Property used or to be used in the ordinary course of business of the Guarantor or its Subsidiaries. "Attributable Indebtedness," when used with respect to any Sale-Leaseback Transaction, means, as at the

time of determination, the present value (discounted at the rate set forth or implicit in the terms of the lease included in such transaction) of the total obligations of the lessee for rental payments (other than amounts required to be paid on account of property taxes, maintenance, repairs, insurance, assessments, utilities, operating and labor costs and other items that do not constitute payments for property rights) during the remaining term of the lease included in such Sale-

Leaseback Transaction (including any period for which such lease has been extended). In the case of any lease that is terminable by the lessee upon the payment of a penalty or other termination payment, such amount shall be the lesser of the amount determined assuming termination upon the first date such lease may be terminated (in which case the amount shall also include the amount of the penalty or termination payment, but no rent shall be considered as required to be paid under such lease subsequent to the first date upon which it may be so terminated) or the amount determined assuming no such termination.

Notwithstanding the foregoing, under the Indenture the Guarantor may, and may permit any Subsidiary to, effect any Sale-Leaseback Transaction that is not excepted by clauses (1) through (4), inclusive, of the first paragraph under "-- Restrictions On Sale-Leasebacks," provided that the Attributable Indebtedness from such Sale-Leaseback Transaction, together with the aggregate principal amount of outstanding debt (other than the debt securities) secured by liens other than Permitted Liens upon Principal Property, do not exceed 10% of Consolidated Net Tangible Assets.

In the Indenture, the term "Subsidiary" means:

(1) the Issuer; or

(2) any corporation, association or other business entity of which more than 50% of the total voting power of the equity interests entitled (without regard to the occurrence of any contingency) to vote in the election of directors, managers or trustees thereof or any partnership of which more than 50% of the partners' equity interests (considering all partners' equity interests as a single class) is, in each case, at the time owned or controlled, directly or indirectly, by the Guarantor, the Issuer or one or more of the other Subsidiaries of the Guarantor or the Issuer or combination thereof.

Merger, Consolidation or Sale of Assets. The Indenture will provide that each of the Guarantor and the Issuer may, without the consent of the holders of any of the debt securities, consolidate with or sell, lease, convey all or substantially all of its assets to, or merge with or into, any partnership, limited liability company or corporation if:

(1) the partnership, limited liability company or corporation formed by or resulting from any such consolidation or merger or to which such assets shall have been transferred (the "successor") is either the Guarantor or the Issuer, as applicable, or assumes all the Guarantor's or the Issuer's, as the case may be, obligations and liabilities under the Indenture and the debt securities (in the case of the Issuer) and the Guarantee (in the case of the Guarantor).

(2) the successor is organized under the laws of the United States, any state or the District of Columbia; and

(3) immediately after giving effect to the transaction no Default or Event of Default shall have occurred and be continuing.

The successor will be substituted for the Guarantor or the Issuer, as the case may be, in the Indenture with the same effect as if it had been an original party to the Indenture. Thereafter, the successor may exercise the rights and powers of the Guarantor or the Issuer, as the case may be, under the Indenture, in its name or in its own name. If the Guarantor or the Issuer sells or transfers all or substantially all of its assets, it will be released from all liabilities and obligations under the Indenture and under the debt securities (in the case of the Issuer) and the Guarantee (in the case of the Guarantor) except that no such release will occur in the case of a lease of all or substantially all of its assets.

EVENTS OF DEFAULT

Each of the following will be an Event of Default under the Indenture with respect to a series of debt securities:

(1) default in any payment of interest on any debt securities of that series when due, continued for 30 days;

(2) default in the payment of principal of or premium, if any, on any debt securities of that series when due at its stated maturity, upon optional redemption, upon declaration or otherwise;

(3) failure by the Guarantor or the Issuer to comply for 60 days after notice with its other agreements contained in the Indenture;

(4) certain events of bankruptcy, insolvency or reorganization of the Issuer or the Guarantor (the "bankruptcy provisions"); or

(5) the Guarantee ceases to be in full force and effect or is declared null and void in a judicial proceeding or the Guarantor denies or disaffirms its obligations under the Indenture or the Guarantee.

However, a default under clause (3) of this paragraph will not constitute an Event of Default until the Trustee or the holders of 25% in principal amount of the outstanding debt securities of that series notify the Issuer and the Guarantor of the default such default is not cured within the time specified in clause (3) of this paragraph after receipt of such notice.

If an Event of Default (other than an Event of Default described in clause (4) above) occurs and is continuing, the Trustee by notice to the Issuer, or the holders of at least 25% in principal amount of the outstanding debt securities of that series by notice to the Issuer and the Trustee, may, and the Trustee at the request of such holders shall, declare the principal of, premium, if any, and accrued and unpaid interest, if any, on all the debt securities of that series to be due and payable. Upon such a declaration, such principal, premium and accrued and unpaid interest will be due and payable immediately. If an Event of Default described in clause (4) above occurs and is continuing, the principal of, premium, if any, and accrued and unpaid interest on all the debt securities will become and be immediately due and payable without any declaration or other act on the part of the Trustee or any holders. The holders of a majority in principal amount of the outstanding debt securities of a series may waive all past defaults (except with respect to nonpayment of principal, premium or interest) and rescind any such acceleration with respect to the debt securities of that series and its consequences if rescission would not conflict with any judgment or decree of a court of competent jurisdiction and all existing Events of Default, other than the nonpayment of the principal of, premium, if any, and interest on the debt securities of that series that have become due solely by such declaration of acceleration, have been cured or waived.

Subject to the provisions of the Indenture relating to the duties of the Trustee, if an Event of Default occurs and is continuing, the Trustee will be under no obligation to exercise any of the rights or powers under the Indenture at the request or direction of any of the holders unless such holders have offered to the Trustee reasonable indemnity or security against any loss, liability or expense. Except to enforce the right to receive payment of principal, premium, if any, or interest when due, no holder may pursue any remedy with respect to the Indenture or the debt securities unless:

(1) such holder has previously given the Trustee notice that an Event of Default is continuing;

(2) holders of at least 25% in principal amount of the outstanding debt securities of that series have requested the Trustee to pursue the remedy;

(3) such holders have offered the Trustee reasonable security or indemnity against any loss, liability or expense;

(4) the Trustee has not complied with such request within 60 days after the receipt of the request and the offer of security or indemnity; and

(5) the holders of a majority in principal amount of the outstanding debt securities of that series have not given the Trustee a direction that, in the opinion of the Trustee, is inconsistent with such request within such 60-day period.

Subject to certain restrictions, the holders of a majority in principal amount of the outstanding debt securities of a series are given the right to direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or of exercising any trust or power conferred on the Trustee with respect to that series of debt securities. The Trustee, however, may refuse to follow any direction that conflicts with law or the Indenture or that the Trustee determines is unduly prejudicial to the rights of any other holder or that would involve the Trustee in personal liability. Prior to taking any action under the Indenture, the Trustee will be entitled to indemnification satisfactory to it in its sole discretion against all losses and expenses caused by taking or not taking such action.

The Indenture provides that if a Default occurs and is continuing and is known to the Trustee, the Trustee must mail to each holder notice of the Default within 90 days after it occurs. Except in the case of a Default in the payment of principal of, premium, if any, or interest on any debt securities, the Trustee may withhold notice if and so long as a committee of trust officers of the Trustee in good faith determines that withholding notice is in the interests of the holders. In addition, the Issuer is required to deliver to the Trustee, within 120 days after the end of each fiscal year, a certificate indicating whether the signers thereof know of any Default that occurred during the previous year. The Issuer also is required to deliver to the Trustee, within 30 days after the occurrence thereof, written notice of any events which would constitute certain Defaults, their status and what action the Issuer is taking or proposes to take in respect thereof.

AMENDMENTS AND WAIVERS

Modifications and amendments of the Indenture may be made by the Issuer, the Guarantor and the Trustee with the consent of the holders of a majority in principal amount of all debt securities then outstanding under the Indenture (including consents obtained in connection with a tender offer or exchange offer for the debt securities). However, without the consent of each holder of outstanding debt securities of each series affected thereby, no amendment may, among other things:

(1) reduce the amount of debt securities whose holders must consent to an amendment;

(2) reduce the stated rate of or extend the stated time for payment of interest on any debt securities;

(3) reduce the principal of or extend the stated maturity of any debt securities;

(4) reduce the premium payable upon the redemption of any debt securities or change the time at which any debt securities may be redeemed as described above under "Optional Redemption" or any similar provision;

(5) make any debt securities payable in money other than that stated in the debt securities;

(6) impair the right of any holder to receive payment of, premium, if any, principal of and interest on such holder's debt securities on or after the due dates therefor or to institute suit for the enforcement of any payment on or with respect to such holder's debt securities;

(7) make any change in the amendment provisions which require each holder's consent or in the waiver provisions; or

(8) release the Guarantor or modify the Guarantee in any manner adverse to the holders.

The holders of a majority in aggregate principal amount of the outstanding debt securities of each series affected thereby, on behalf of all such holders, may waive compliance by the Issuer and the Guarantor with certain restrictive provisions of the Indenture. Subject to certain rights of the Trustee as provided in the Indenture, the holders of a majority in aggregate principal amount of the debt securities of each series affected thereby, on behalf of all such holders, may waive any past default under the Indenture (including any such waiver obtained in connection with a tender offer or exchange offer for the debt securities), except a default in the payment of principal, premium or interest or a default in respect of a provision that under the Indenture that cannot be modified or amended without the consent of all holders of the series of debt securities that is affected.

Without the consent of any holder, the Issuer, the Guarantor and the Trustee may amend the Indenture to:

(1) cure any ambiguity, omission, defect or inconsistency;

(2) provide for the assumption by a successor corporation, partnership, trust or limited liability company of the obligations of the Guarantor or the Issuer under the Indenture;

(3) provide for uncertificated debt securities in addition to or in place of certificated debt securities (provided that the uncertificated debt securities are issued in registered form for purposes of Section 163(f) of the Code, or in a manner such that the uncertificated debt securities are described in Section 163(f)(2)(B) of the Code);

(4) add guarantees with respect to the debt securities;

(5) secure the debt securities;

(6) add to the covenants of the Guarantor or the Issuer for the benefit of the holders or surrender any right or power conferred upon the Guarantor or the Issuer;

(7) make any change that does not adversely affect the rights of any holder; or

(8) comply with any requirement of the Commission in connection with the qualification of the Indenture under the Trust Indenture Act.

The consent of the holders is not necessary under the Indenture to approve the particular form of any proposed amendment. It is sufficient if such consent approves the substance of the proposed amendment. After an amendment under the Indenture becomes effective, the Issuer is required to mail to the holders a notice briefly describing such amendment. However, the failure to give such notice to all the holders, or any defect therein, will not impair or affect the validity of the amendment.

DEFEASANCE

The Issuer at any time may terminate all its obligations under a series of debt securities and the Indenture ("legal defeasance"), except for certain obligations, including those respecting the defeasance trust and obligations to register the transfer or exchange of the debt securities, to replace mutilated, destroyed, lost or stolen debt securities and to maintain a registrar and paying agent in respect of the debt securities. If the Issuer exercises its legal defeasance option, the Guarantee will terminate with respect to that series.

The Issuer at any time may terminate its obligations under covenants described under "Certain Covenants" (other than "Merger and Consolidation"), the bankruptcy provisions with respect to the Guarantor and the Guarantee provision described under "Events of Default" above with respect to a series of debt securities ("covenant defeasance").

The Issuer may exercise its legal defeasance option notwithstanding its prior exercise of its covenant defeasance option. If the Issuer exercises its legal defeasance option, payment of the affected series of debt securities may not be accelerated because of an Event of Default with respect thereto. If the Issuer exercises its covenant defeasance option, payment of the affected series of debt securities may not be accelerated because of an Event of Default specified in clause (3), (4), (with respect only to the Guarantor) or (5) under "Events of Default" above.

In order to exercise either defeasance option, the Issuer must irrevocably deposit in trust (the "defeasance trust") with the Trustee money or U.S. Government Obligations for the payment of principal, premium, if any, and interest on the series of debt securities to redemption or maturity, as the case may be, and must comply with certain other conditions, including delivery to the Trustee of an opinion of counsel (subject to customary exceptions and exclusions) to the effect that holders of the series of debt securities will not recognize income, gain or loss for Federal income tax purposes as a result of such deposit and defeasance and will be subject to Federal income tax on the same amount and in the same manner and at the same times as would have been the case if such deposit and defeasance had not occurred. In the case of legal defeasance only, such opinion of counsel must be based on a ruling of the Internal Revenue Service or other change in applicable Federal income tax law.

NO PERSONAL LIABILITY OF GENERAL PARTNER

The General Partner and its directors, officers, employees, incorporators and stockholders, as such, shall have no liability for any obligations of the Guarantor or the Issuer under the debt securities, the Indenture or the Guarantee or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each holder by accepting a debt security waives and releases all such liability. The waiver and release are part of the consideration for issuance of the debt securities. Such waiver may not be effective to waive liabilities under the federal securities laws and it is the view of the Commission that such a waiver is against public policy.

SUBORDINATION

Debt securities of a series may be subordinated to Senior Indebtedness (as defined below) to the extent set forth in the Prospectus Supplement relating thereto. Subordinated debt securities will be subordinate in right of payment, to the extent and in the manner set forth in the Indenture and the Prospectus Supplement relating thereto, to the prior payment of all indebtedness of the Issuer and the Guarantor that is designated as "Senior Indebtedness" with respect to the series. "Senior Indebtedness" is defined generally to include all notes or other evidences of indebtedness for money borrowed by the Issuer, including guarantees, not expressed to be subordinate or junior in right of payment to any other indebtedness of the Issuer.

Upon any payment or distribution of assets of the Issuer to creditors or upon a total or partial liquidation or dissolution of the Issuer or in a bankruptcy, receivership or similar proceeding relating to the Issuer or its property, holders of Senior Indebtedness shall be entitled to receive payment in full in cash of the Senior Indebtedness before holders of subordinated debt securities shall be entitled to receive any payment of principal, premium or interest with respect to the subordinated debt securities, and until the Senior Indebtedness is paid in full, any distribution to which holders of subordinated debt securities would otherwise be entitled shall be made to the holders of Senior Indebtedness (except that the holders may receive shares of stock and any debt securities that are subordinated to Senior Indebtedness to at least the same extent as the subordinated debt securities).

We may not make any payments of principal, premium or interest with respect to subordinated debt securities, make any deposit for the purpose of defeasance of the subordinated debt securities, or repurchase, redeem or otherwise retire (except, in the case of subordinated debt securities that provide for a mandatory sinking fund, by our delivery of subordinated debt securities to the Trustee in satisfaction of our sinking fund obligation) any subordinated debt securities if (a) any principal, premium or interest with respect to Senior

Indebtedness is not paid within any applicable grace period (including at maturity), or (b) any other default on Senior Indebtedness occurs and the maturity of the Senior

Indebtedness is accelerated in accordance with its terms, unless, in either case, the default has been cured or waived and the acceleration has been rescinded, the Senior Indebtedness has been paid in full in cash, or the Issuer and the Trustee receive written notice approving the payment from the representatives of each issue of "Designated Senior Indebtedness" (which will include the Bank Indebtedness and any other specified issue of Senior Indebtedness of at least $100 million). During the continuance of any default (other than a default described in clause (a) or (b) above) with respect to any Senior Indebtedness pursuant to which the maturity thereof may be accelerated immediately without further notice (except such notice as may be required to effect the acceleration) or the expiration of any applicable grace periods, the Issuer may not pay the subordinated debt securities for a period (the "Payment Blockage Period") commencing on the receipt by the Issuer and the Trustee of written notice of the default from the representative of any Designated Senior Indebtedness specifying an election to effect a Payment Blockage Period (a "Blockage Notice"). The Payment Blockage Period may be terminated before its expiration by written notice to the Trustee and us from the person who have the Blockage Notice, by repayment in full in cash of the Senior Indebtedness with respect to which the Blockage Notice was given, or because the default giving rise to the Payment Blockage Period is no longer continuing. Unless the holders of the Senior Indebtedness shall have accelerated the maturity thereof, the Issuer may resume payments on the subordinated debt securities after the expiration of the Payment Blockage Period. Not more than one Blockage Notice may be given in any period of 360 consecutive days unless the first Blockage Notice within the 360-day period is given by or on behalf of holders of Designated Senior Indebtedness other than the Bank Indebtedness, in which case, the representative of the Bank Indebtedness may give another Blockage Notice within the period. In no event, however, may the total number of days during which any Payment Blockage Period or Periods is in effect exceed 179 days in the aggregate during any period of 360 consecutive days. After all Senior Indebtedness is paid in full and until the subordinated debt securities are paid in full, holders of the subordinated debt securities shall be subrogated to the rights of holders of Senior Indebtedness to receive distributions applicable to Senior Indebtedness.

By reason of the subordination, in the event of insolvency, our creditors who are holders of Senior Indebtedness, as well as certain of our general creditors, may recover more, ratably, than the holders of the subordinated debt securities.

BOOK ENTRY, DELIVERY AND FORM

The debt securities of a series may be issued in whole or in part in the form of one or more global certificates that will be deposited with a depositary identified in a prospectus supplement.

Unless otherwise stated in any prospectus supplement, The Depository Trust Company, New York, New York ("DTC") will act as depositary. Book-entry debt securities of a series will be issued in the form of a global security that will be deposited with DTC. This means that we will not issue certificates to each holder. One global security will be issued to DTC who will keep a computerized record of its participants (for example, your broker) whose clients have purchased the debt securities. The participant will then keep a record of its clients who purchased the debt securities. Unless it is exchanged in whole or in part for a certificated securities, a global security may not be transferred; except that DTC, its nominees and their successors may transfer a global security as a whole to one another.

Beneficial interests in global securities will be shown on, and transfers of global securities will be made only through, records maintained by DTC and its participants.

DTC has provided us the following information: DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" with the meaning of the New York Banking Law, a member of the United States Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code and a "clearing agency" registered under the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds securities that its participants ("Direct Participants") deposit with DTC. DTC also records the settlement among Direct Participants of securities transactions, such as transfers and pledges, in deposited securities through computerized records for Direct Participant's accounts. This eliminates the need to exchange certificates. Direct Participants include securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations.

DTC's book-entry system is also used by other organizations such as securities brokers and dealers, banks and trust companies that work through a Direct Participant. The rules that apply to DTC and its participants are on file with the Commission.

DTC is owned by a number of its Direct Participants and by the New York Stock Exchange, Inc., The American Stock Exchange, Inc. and the National Association of Securities Dealers, Inc.

We will wire principal and interest payments to DTC's nominee. We and the Trustee will treat DTC's nominee as the owner of the global securities for all purposes. Accordingly, we, the Trustee and any paying agent will have no direct responsibility or liability to pay amounts due on the global securities to owners of beneficial interests in the global securities.

It is DTC's current practice, upon receipt of any payment of principal or interest, to credit Direct Participants' accounts on the payment date according to their respective holdings of beneficial interests in the global securities as shown on DTC's records. In addition, it is DTC's current practice to assign any consenting or voting rights to Direct Participants whose accounts are credited with debt securities on a record date, by using an omnibus proxy. Payments by participants to owners of beneficial interests in the global securities, and voting by participants, will be governed the customary practices between the participants and owners of beneficial interests, as is the case with debt securities held for the account of customers registered in "street name." However, payments will be the responsibility of the participants and not of DTC, the Trustee or us.

Debt securities represented by a global security will be exchangeable for certificated securities with the same terms in authorized denominations only if:

- DTC notifies us that it is unwilling or unable to continue as depositary or if DTC ceases to be a clearing agency registered under applicable law and a successor depositary is not appointed by us within 90 days; or

- we determine not to require all of the debt securities of a series to be represented by a global security and notify the Trustee of our decision.

LIMITATIONS ON ISSUANCE OF BEARER SECURITIES

The debt securities of a series may be issued as Registered Securities (which will be registered as to principal and interest in the register maintained by the registrar for the debt securities) or Bearer Securities (which will be transferable only by delivery). If the debt securities are issuable as Bearer Securities, certain special limitations and conditions will apply.

In compliance with United States federal income tax laws and regulations, we and any underwriter, agent or dealer participating in an offering of Bearer Securities will agree that, in connection with the original issuance of the Bearer Securities and during the period ending 40 days after the issue date, they will not offer, sell or deliver any such Bearer Securities, directly or indirectly, to a United States Person (as defined below) or to any person within the United States, except to the extent permitted under United States Treasury regulations.

Bearer Securities will bear a legend to the following effect: "Any United States person who holds this obligation will be subject to limitations under the United States federal income tax laws, including the limitations provided in Sections 165(j) and 1287(a) of the Internal Revenue Code." The sections referred to in the legend provide that, with certain exceptions, a United States taxpayer who holds Bearer Securities will not be allowed to deduct any loss with respect to, and will not be eligible for capital gain treatment with respect to any gain realized on the sale, exchange, redemption or other disposition of, the Bearer Securities.

For this purpose, "United States" includes the United States of America and its possessions, and "United States person" means a citizen or resident of the United States, a corporation, partnership or other entity created or organized in or under the laws of the United States, or an estate or trust the income of which is subject to United States federal income taxation regardless of its source.

Pending the availability of a definitive global security or individual Bearer Securities, as the case may be, debt securities that are issuable as Bearer Securities may initially be represented by a single temporary global security, without interest coupons, to be deposited with a common depositary in London for Morgan Guaranty Trust Company of New York, Brussels Office, as operator of the Euroclear System ("Euroclear"), or Centrale de Livraison de Valeurs Mobilieres S.A. ("CEDEL") for credit to the accounts designated by or on behalf of the purchasers thereof. Following the availability of a definitive global security in bearer form, without coupons attached, or individual Bearer Securities and subject to any further limitations described in the applicable Prospectus Supplement, the temporary global security will be exchangeable for interests in the definitive global security or for the individual Bearer Securities, respectively, only upon receipt of a "Certificate of Non-U.S. Beneficial Ownership," which is a certificate to the effect that a beneficial interest in a temporary global security is owned by a person that is not a United States Person or is owned by or through a financial institution in compliance with applicable United States Treasury regulations. No Bearer Security will be delivered in or to the United States. If so specified in the applicable Prospectus Supplement, interest on a temporary global security will be paid to each of Euroclear and CEDEL with respect to that portion of the temporary global security held for its account, but only upon receipt as of the relevant interest payment date of a Certificate of Non-U.S. Beneficial Ownership.

THE TRUSTEE

We may appoint a separate Trustee for any series of debt securities. As used herein in the description of a series of debt securities, the term "Trustee" refers to the Trustee appointed with respect to the series of debt securities.

We may maintain banking and other commercial relationships with the Trustee and its affiliates in the ordinary course of business, and the Trustee may own debt securities.

GOVERNING LAW

The Indenture provides that it and the debt securities will be governed by, and construed in accordance with, the laws of the State of New York.

DESCRIPTION OF COMMON UNITS

THE UNITS

As of December 31, 2000, we have outstanding 46,524,515 common units, 21,409,870 subordinated units and 16,500,000 convertible special units. The common units, the subordinated units and the convertible special units represent limited partner interests in the Company, which entitle the holders thereof to participate in Company distributions and exercise the rights or privileges available to limited partners under our Partnership Agreement. A summary of the important provisions of our Partnership Agreement and a copy of our Partnership Agreement are included in our reports filed with the Commission.

The outstanding common units are listed on the New York Stock Exchange under the symbol "EPD." Any additional common units we issue will also be listed on the NYSE.

CASH DISTRIBUTION POLICY

GENERAL

We distribute to our partners, on a quarterly basis, all of our available cash. Available cash is defined in the Partnership Agreement and generally means, with respect to any calendar quarter, all cash on hand at the end of such quarter less the amount of cash reserves that is necessary or appropriate in the reasonable discretion of the General Partner to (1) provide for the proper conduct of the Company's business, (2) comply with applicable law or any Company debt instrument or other agreement (including reserves for future capital expenditures and for our future credit needs) or (3) provide funds for distributions to unitholders and the General Partner in respect of any one or more of the next four quarters.

Cash distributions are characterized as distributions from either operating surplus or capital surplus. This distinction affects the amounts distributed to unitholders relative to the General Partner, and under certain circumstances it determines whether holders of subordinated units receive any distributions. See "-- Quarterly Distributions of Available Cash."

Operating surplus is defined in the Partnership Agreement and refers generally to (a) the sum of (1) the cash balance of the Company on July 31, 1998, the closing date of our initial public offering of common units (excluding $46.5 million spent from the proceeds of that offering on new projects), (2) all cash receipts of the Company from its operations since July 31, 1998 (excluding certain cash receipts that the General Partner designates as operating surplus), less (b) the sum of (1) all Company operating expenses, (2) debt service payments (including reserves therefor but not including payments required in connection with the sale of assets or any refinancing with the proceeds of new indebtedness or an equity offering), (3) maintenance capital expenditures and (4) reserves established for future Company operations, in each case since July 31, 1998. Capital surplus is generally generated only by borrowings (other than borrowings for working capital purposes), sales of debt and equity securities and sales or other dispositions of assets for cash (other than inventory, accounts receivable and other assets disposed of in the ordinary course of business).

To avoid the difficulty of trying to determine whether available cash distributed by the Company is from operating surplus or from capital surplus, all available cash distributed by the Company from any source will be treated as distributed from operating surplus until the sum of all available cash distributed since July 31, 1998 equals the operating surplus as of the end of the quarter prior to such distribution. Any available cash in excess of such amount (irrespective of its source) will be deemed to be from capital surplus and distributed accordingly.

If available cash from capital surplus is distributed in respect of each common unit in an aggregate amount per common unit equal to the $22.00 initial public offering price of the common units, plus any common unit arrearages, the distinction between operating surplus and capital surplus will cease, and all distributions of available cash will be treated as if they were from operating surplus. We do not anticipate that there will be significant distributions from capital surplus.

The subordinated units are a separate class of interests in the Company, and the rights of holders of such interests to participate in distributions to partners differ from the rights of the holders of common units. For any given quarter, any available cash will be distributed to the General Partner and to the holders of common units, and may also be distributed to the holders of subordinated units depending upon the amount of available cash for the quarter, the amount of common unit arrearages, if any, and other factors discussed below.

A total of 14,500,000 convertible special units were issued as part of the purchase price of Tejas Natural Gas Liquids LLC. These units do not accrue distributions and are not entitled to cash distributions until their conversion into an equal number of common units between August 1, 2000 and August 1, 2002. On August 1, 2000, 1,000,000 of the convertible special units were converted into an equal number of common units. As an additional part of the purchase price of Tejas Natural Gas Liquids LLC, we agreed to issue up to 6,000,000 more convertible special units to the seller if the volumes of natural gas that we process for Shell Oil Company and its affiliates reach certain agreed upon levels in 2000 and 2001. These additional contingent units would convert into an equal number of common units between August 1, 2002 and August 1, 2003. On August 1, 2000, 3,000,000 of these contingent convertible special units were issued to the seller under our foregoing agreement.

The incentive distributions represent the right of the General Partner to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the target distribution levels have been achieved. The target distribution levels are based on the amounts of available cash from operating surplus distributed in excess of the payments made with respect to the minimum quarterly distribution of $0.45 per unit and common unit arrearages, if any, and the related 2% distribution to the General Partner.

Subject to certain limitations contained in the Partnership Agreement, the Company has the authority to issue additional common units or other equity securities of the Company for such consideration and on such terms and conditions as are established by the General Partner in its sole discretion and without the approval of the unitholders. It is possible that the Company will fund acquisitions of assets or other capital projects through the issuance of additional common units or other equity securities of the Company. Holders of any additional common units issued by the Company will be entitled to share equally with the then-existing holders of common units in distributions of available cash by the Company. In addition, the issuance of additional common units may dilute the value of the interests of the then-existing holders of common units in the net assets of the Company. The General Partner will be required to make an additional capital contribution to the Company or the Operating Partnership in connection with the issuance of additional common units.

The discussion in the sections below indicates the percentages of cash distributions required to be made to the General Partner and the holders of common units and the circumstances under which holders of subordinated units are entitled to receive cash distributions and the amounts thereof.

QUARTERLY DISTRIBUTIONS OF AVAILABLE CASH

The Company will make distributions to its partners with respect to each calendar quarter of the Company prior to its liquidation in an amount equal to 100% of its available cash for such quarter. The Company expects to make distributions of all available cash within approximately 45 days after the end of each quarter to holders of record on the applicable record date. The minimum quarterly distribution and the target distribution levels are also subject to certain other adjustments as described below under "-- Distributions from Capital Surplus" and "-- Adjustment of Minimum Quarterly Distribution and Target Distribution Levels."

With respect to each quarter during the Subordination Period, to the extent there is sufficient available cash, the holders of common units will have the right to receive the minimum quarterly distribution of $0.45 per unit, plus any common unit arrearages, prior to any distribution of available cash to the holders of subordinated units. Upon expiration of the Subordination Period, all subordinated units will be converted on a one-for-one basis into common units and will participate pro rata with all other common units in future distributions of available cash. Under certain circumstances, up to 50% of the subordinated units may convert into common units prior to the expiration of the Subordination Period.

Common units will not accrue arrearages with respect to distributions for any quarter after the Subordination Period, and subordinated units will not accrue any arrearages with respect to distributions for any quarter.

DISTRIBUTIONS FROM OPERATING SURPLUS DURING SUBORDINATED PERIOD

The Subordination Period will generally extend until the first day of any quarter beginning after June 30, 2003 in respect of which (1) distributions of available cash from operating surplus on the common units and the subordinated units with respect to each of the three consecutive, non-overlapping, four-quarter periods immediately preceding such date equaled or exceeded the sum of the minimum quarterly distribution on all of the outstanding common units and subordinated units during such periods, (2) the adjusted operating surplus generated during each of the three consecutive, non-overlapping, four-quarter periods immediately preceding such date equaled or exceeded the sum of the minimum quarterly distribution on all of the common units and subordinated units that were outstanding during such period on a fully diluted basis and the related distribution on the general partner interests in the Company and the Operating Partnership and (3) there are no outstanding common unit arrearages.

Prior to the end of the Subordination Period, a portion of the subordinated units will convert into common units on a one-for-one basis on the first day after the record date established for the distribution in respect of any quarter ending on or after (a) June 30, 2001 with respect to 5,352,468 subordinated units, and (b) June 30, 2002 with respect to 5,352,468 subordinated units in respect of which (1) distributions of available cash from operating surplus on the common units and the subordinated units with respect to each of the three consecutive, non-overlapping, four-quarter periods immediately preceding such date equaled or exceeded the sum of the minimum quarterly distribution on all of the outstanding common units and subordinated units during such periods, (2) the adjusted operating surplus generated during each of the three consecutive, non-overlapping, four-quarter periods immediately preceding such date equaled or exceeded the sum of $0.45 per unit on all of the common units and subordinated units that were outstanding during such period on a fully diluted basis and the related distribution on the general partner interests in the Company and the Operating Partnership and (3) there are no outstanding common unit arrearages; provided, however, that the early conversion of the second 5,352,468 subordinated units may not occur until at least one year following the early conversion of the first 5,352,468 subordinated units.

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 distribution on available cash. In addition, if the General Partner is removed as the general partner of the Company under circumstances where cause does not exist and units held by the General Partner and its affiliates are not voted in favor of such removal, (1) the Subordination Period will end and all outstanding subordinated units will immediately convert into common units on a one-for-one basis, (2) any existing common unit arrearages will be extinguished and (3) the General Partner will have the right to convert its general partner interest into common units or to receive cash in exchange for such interests.

Adjusted operating surplus for any period generally means operating surplus generated during such period, less (a) any net increase in working capital borrowings during such period and (b) any net reduction in cash reserves for operating expenditures during such period not relating to an operating expenditure made during such period, and plus (x) any net decrease in working capital borrowings during such period and (y) any net increase in cash reserves for operating expenditures during such period required by any debt instrument for the repayment of principal, interest or premium. Operating surplus generated during a period is equal to the difference between (1) the operating surplus determined at the end of such period and (2) the operating surplus determined at the beginning of such period.

Distributions by the Company of available cash from operating surplus with respect to any quarter during the Subordination Period will be made in the following manner:

first, 98% to the common unitholders, pro rata, and 2% to the General Partner, until there has been distributed in respect of each outstanding common unit an amount equal to $0.45 per unit for such quarter.

second, 98% to the common unitholders, pro rata, and 2% to the General Partner, until there has been distributed in respect of each outstanding common unit an amount equal to any common unit arrearages accrued and unpaid with respect to any prior quarters during the Subordination Period;

third, 98% to the subordinated unitholders, pro rata and 2% to the

General Partner, until there has been distributed in respect of each outstanding common unit an amount equal to $0.45 per unit; and

thereafter, in the manner described in "-- Incentive Distributions -- Hypothetical Annualized Yield" below.

The above references to the 2% of available cash from operating surplus distributed to the General Partner are references to the amount of the percentage interest in distributions from the Company and the Operating Partnership of the General Partner (exclusive of its or any of its affiliates' interests as holders of common units or subordinated units).

The General Partner owns a 1% general partner interests in the Company and a 1.0101% general partner interests in the Operating Partnership. With respect to any common unit, the term "common unit arrearages" refers to the amount by which the minimum quarterly distribution of $0.45 per unit in any quarter during the Subordination Period exceeds the distribution of available cash from operating surplus actually made for such quarter on a common unit issued in our initial public offering, cumulative for such quarter and all prior quarters during the Subordination Period. Common unit arrearages will not accrue interest.

DISTRIBUTIONS FROM OPERATING SURPLUS AFTER SUBORDINATION PERIOD

Distributions by the Company of available cash from the operating surplus with respect to any quarter after the Subordination Period will be made in the following manner:

first, 98% to all unitholders, pro rata and 2% to the General Partner, until there has been distributed in respect of each unit an amount equal to $0.45; and

thereafter, in the manner described in "-- Incentive Distributions" below.

INCENTIVE DISTRIBUTIONS

For any quarter for which available cash from operating surplus is distributed to the Common and subordinated unitholders in an amount equal to $0.45 per unit on all units and to the common unitholders in an amount equal to any unpaid common unit arrearages, then any additional available cash from operating surplus in respect of such quarter will be distributed among the unitholders and the General Partner in the following manner:

first, 98% to all unitholders, pro rata, and 2% to the General Partner, until the unitholders have received (in addition to any distributions to common unitholders to eliminate common unit arrearages) a total of $0.506 for such quarter in respect of each outstanding unit (the "First Target Distribution");

second, 85% to all unitholders, pro rata, and 15% to the General Partner, until the unitholders have received (in addition to any distribution to common unitholders to eliminate common unit arrearages) a total of $0.617 for such quarter in respect of each outstanding unit (the "Second Target Distribution");

third, 75% to all unitholders, pro rata, and 25% to the General Partner, until the unitholders have received (in addition to any distributions to common unitholders to eliminate common unit arrearages) a total of $0.784 for such quarter in respect of each outstanding unit (the "Third Target Distribution"); and

thereafter, 50% to all unitholders, pro rata, and 50% to the General Partner.

The distributions to the General Partner set forth above that are in excess of its aggregate 2% general partner interest represent the Incentive Distributions.

DISTRIBUTIONS FROM CAPITAL SURPLUS

Distributions by the Company of available cash from capital surplus will be made in the following manner:

first, 98% to all unitholders, pro rata, and 2% to the General Partner, until the Company has distributed, in respect of each outstanding common unit issued in our initial public offering, available cash from capital surplus in an aggregate amount per common unit equal to the initial unit price of $22.00;

second, 98% to the holders of common units, pro rata, and 2% to the General Partner, until the Company has distributed, in respect of each outstanding common unit, available cash from capital surplus in an aggregate amount equal to any unpaid common unit arrearages with respect to such common unit; and

thereafter, all distributions of available cash from capital surplus will be distributed as if they were from operating surplus.

As a distribution of available cash from capital surplus is made, it is treated as if it were a repayment of the initial unit price of $22.00 per unit.

To reflect such repayment, the minimum quarterly distribution of $0.45 per unit and the target distribution levels will be adjusted downward by multiplying each such amount by a fraction, the numerator of which is the unrecovered capital of the common units immediately after giving effect to such repayment and the denominator of which is the unrecovered capital of the common units immediately prior to such repayment. This adjustment to the minimum quarterly distribution may make it more likely that subordinated units will be converted into common units (whether pursuant to the termination of the Subordination Period or to the provisions permitting early conversion of some subordinated units) and may accelerate the dates at which such conversions occur.

When "payback" of the initial unit price has occurred, i.e., when the unrecovered capital of the common units is zero (and any accrued common unit arrearages have been paid), the minimum quarterly distribution and each of the target distribution levels will have been reduced to zero for subsequent quarters. Thereafter, all distributions of available cash from all sources will be treated as if they were from operating surplus. Because the minimum quarterly distribution and the target distribution levels will have been reduced to zero, the General Partner will be entitled thereafter to receive 50% of all distributions of available cash in its capacity as General Partner (in addition to any distributions to which it or its affiliates may be entitled as holders of units).

Distributions of available cash from capital surplus will not reduce the minimum quarterly distribution or target distribution levels for the quarter with respect to which they are distributed.

ADJUSTMENT OF MINIMUM QUARTERLY DISTRIBUTION AND TARGET DISTRIBUTION LEVELS

In addition to reductions of the minimum quarterly distribution and target distribution levels made upon a distribution of available cash from capital surplus, the minimum quarterly distribution, the target distribution levels, the unrecovered capital, the number of additional common units issuable during the Subordination Period without a unitholder vote, the number of common units issuable upon conversion of the subordinated units and other amounts calculated on a per unit basis will be proportionately adjusted upward or downward, as appropriate, in the event of any combination or subdivision of common units (whether effected by a distribution payable in common units or otherwise), but not by reason of the issuance of additional common units for cash or property. For example, in the event of a two-for-one split of the common units (assuming no prior adjustments), the minimum quarterly distribution, each of the target distribution levels and the unrecovered capital of the common units would each be reduced to 50% of its initial level.

The minimum quarterly distribution and the target distribution levels may also be adjusted if legislation is enacted or if existing law is modified or interpreted by the relevant governmental authority in a manner that causes the Company to become taxable as a corporation or otherwise subjects the Company to taxation as an entity for federal, state or local income tax purposes. In such event, the minimum quarterly distribution and the target distribution levels would be reduced to an amount equal to the product of (1) the minimum quarterly distribution and each of the target distribution levels, respectively, multiplied by (2) one minus the sum of (x) the maximum effective federal income tax rate to which the Company is then subject as an entity plus (y) any increase that results from such legislation in the effective overall state and local income tax rate to which the Company is subject as an entity for the taxable year in which such event occurs (after taking into account the benefit of any deduction allowable for federal income tax purposes with respect to the payment of state and local income taxes). For example, assuming the Company was not previously subject to state and local income tax, if the Company were to become taxable as an entity for federal income tax purposes and the Company became subject to a maximum marginal federal, and effective state and local, income tax rate of 38%, then the minimum quarterly distribution and the target distribution levels would each be reduced to 62% of the amount thereof immediately prior to such adjustment.

DISTRIBUTIONS OF CASH UPON LIQUIDATION

Following the commencement of the dissolution and liquidation of the Company, assets will be sold or otherwise disposed of from time to time and the partners' capital account balances will be adjusted to reflect any resulting gain or loss in the manner provided in the Partnership Agreement. The proceeds of such liquidation will first be applied to the payment of creditors of the Company in the order of priority provided in the Partnership Agreement and by law and, thereafter, be distributed to the unitholders and the General Partner in accordance with their respective capital account balances as so adjusted.

Partners are entitled to liquidating distributions in accordance with capital account balances. The allocations of gains and losses upon liquidation are intended, to the extent possible, to entitle the holders of outstanding common units to a preference over the holders of outstanding subordinated units upon the liquidation of the Company, to the extent required to permit common unitholders to receive their unrecovered capital plus any unpaid common unit arrearages. Thus, net losses recognized upon liquidation of the Company will be allocated to the holders of the subordinated units to the extent of their capital account balances before any loss is allocated to the holders of the common units, and net gains recognized upon liquidation will be allocated first to restore negative balances in the capital account of the General Partner and any unitholders and then to the common unitholders until their capital account balances equal their unrecovered capital plus unpaid common unit arrearages. However, no assurance can be given that there will be sufficient gain upon liquidation of the Company to enable the holders of common units to fully recover all of such amounts, even though there may be cash available after such allocation for distribution to the holders of subordinated units.

If the liquidation of the Company occurs before the end of the Subordination Period, any net gain (or unrealized gain attributable to assets distributed in kind) will be allocated to the partners as follows:

first, to the General Partner and the holders of units having negative balances in their capital accounts to the extent of and in proportion to such negative balances:

second, 98% to the holders of common units, pro rata, and 2% to the General Partner, until the capital account for each common unit is equal to the sum of (1) the unrecovered capital in respect of such common unit, (2) the amount of the minimum quarterly distribution for the quarter during which liquidation of the Company occurs and (3) any unpaid common unit arrearages in respect of such common unit;

third, 98% to the holders of subordinated units, pro rata, and 2% to the General Partner, until the capital account for each common unit is equal to the sum of (1) the unrecovered capital in respect of such common unit, (2) the amount of the minimum quarterly distribution for the quarter during which liquidation of the Company occurs and (3) any unpaid common unit arrearages in respect of such common unit;

fourth, 98% to all unitholders, pro rata, and 2% to the General Partner, until there has been allocated under this paragraph fourth an amount per unit equal to (a) the sum of the excess of the First Target Distribution per unit over the minimum quarterly distribution per unit for each quarter of the Company's existence, less (b) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the minimum quarterly distribution per unit that were distributed 98% to the unitholders, pro rata, and 2% to the General Partner for each quarter of the Company's existence;

fifth, 85% to all unitholders, pro rata, and 15% to the General Partner, until there has been allocated under this paragraph fifth an amount per unit equal to (a) the sum of the excess of the Second Target Distribution per unit over the First Target Distribution per unit for each quarter of the Company's existence, less (b) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the First Target Distribution per unit that were distributed 85% to the unitholders, pro rata, and 15% to the General Partner for each quarter of the Company's existence;

sixth, 75% to all unitholders, pro rata, and 25% to the General Partner, until there has been allocated under this paragraph sixth an amount per unit equal to (a) the sum of the excess of the Third Target Distribution per unit over the Second Target Distribution per unit for each quarter of the Company's existence, less (b) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the Second Target Distribution per unit that were distributed 75% to the unitholders, pro rata, and 25% to the General Partner for each quarter of the Company's existence; and

thereafter, 50% to all unitholders, pro rata, and 50% to the General Partner.

If the liquidation occurs after the Subordination Period, the distinction between common units and subordinated units will disappear, so that clauses (ii) and (iii) of paragraph second above and all of paragraph third above will no longer be applicable.

Upon liquidation of the Company, any loss will generally be allocated to the General Partner and the unitholders as follows:

first, 98% to holders of subordinated units in proportion to the positive balances in their respective capital accounts and 2% to the General Partner, until the capital accounts of the holders of the subordinated units have been reduced to zero;

second, 98% to the holders of common units in proportion to the positive balances in their respective capital accounts and 2% to the General Partner, until the capital accounts of the common unitholders have been reduced to zero; and

thereafter, 100% to the General Partner.

If the liquidation occurs after the Subordination Period, the distinction between common units and subordinated units will disappear, so that all of paragraph first above will no longer be applicable.

In addition, interim adjustments to capital accounts will be made at the time the Company issues additional partnership interests in the Company or makes distributions of property. Such adjustments will be based on the fair market value of the partnership interests or the property distributed and any gain or loss resulting therefrom will be allocated to the unitholders and the General Partner in the same manner as gain or loss is allocated upon liquidation. In the event that positive interim adjustments are made to the capital accounts, any subsequent negative adjustments to the capital accounts resulting from the issuance of additional partnership interests in the Company, distributions of property by the Company, or upon liquidation of the Company, will be allocated in a manner which results, to the extent possible, in the capital account balances of the General Partner equaling the amount which would have been the General Partner's capital account balances if no prior positive adjustments to the capital accounts had been made.

TRANSFER AGENT AND REGISTRAR

ChaseMellon Shareholder Services, LLC is our registrar and transfer agent for the common units. You may contact them at the following address:

Mellon Investor Services LLC
Overpeck Center
85 Challenger Road
Ridgefield Park, NJ 07760

All fees charged by the transfer agent for transfers of common units will be borne by us and not by the holders of common units, except that fees similar to those customarily paid by stockholders for surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges, special charges for services requested by a holder of a common unit and other similar fees or charges will be borne by the affected holder.

TRANSFER OF COMMON UNITS

Until a common unit has been transferred on the books of the Company, the Company and the transfer agent, notwithstanding any notice to the contrary, may treat the record holder thereof as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations. Any transfers of a common unit will not be recorded by the transfer agent or recognized by the Company unless the transferee executes and delivers a transfer application. By executing and delivering a transfer application (the form of which is set forth on the reverse side of the certificates representing the common units), the transferee of common units (i) becomes the record holder of such common units and shall constitute an assignee until admitted into the Company as a substitute limited partner, (ii) automatically requests admission as a substituted limited partner in the Company, (iii) agrees to be bound by the terms and conditions of, and executes, the Partnership Agreement, (iv) represents that such transferee has the capacity, power and authority to enter into the Partnership Agreement, (v) grants powers of attorney to officers of the General Partner and any liquidator of the Company as specified in the Partnership Agreement and (vi) makes the consents and waivers contained in the Partnership Agreement. An assignee will become a substituted limited partner of the Company in the respect of the transferred common units upon the consent of the General Partner and the recordation of the name of the assignee on the books and records of the company. Such consent may be withheld in the sole discretion of the General Partner.

Common units are securities and are transferable according to the laws governing transfer of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to request admission as a substituted limited partner in the Company in the respect of transferred common units. A purchaser or transferee of common units who does not execute and deliver a transfer application obtains only (a) the right to assign the common units to a purchaser or other transferee and (b) the right to transfer the right to seek admission as a substituted limited partner in the Company with respect to the transferred common units. Thus, a purchaser or transferee of common units who does not execute and deliver a transfer application will not receive cash distributions or federal income tax allocations unless the common units are held in a nominee or "street name" account and the nominee or broker has executed and delivered a transfer application with respect to such common units, and may not receive certain federal income tax information or reports furnished to record holders of common units. The transferor of common units will have a duty to provide such transferee with all information that may be necessary to obtain registration of the transfer of common units, that the transferor will not have a duty to insure the execution of the transfer application by the transferee and will have no liability or responsibility if such transferee neglects to or chooses not to execute and forward the transfer application to the transfer agent.

TAX CONSIDERATIONS

This section is a summary of all the material tax considerations that may be relevant to prospective unitholders who are individual citizens or residents of the United States and, unless otherwise noted in the following discussion, expresses the opinion of Vinson & Elkins L.L.P., special counsel to the General Partner and us, insofar as it relates to matters of United States federal income tax law and legal conclusions with respect to those matters. This section is based upon current provisions of the Internal Revenue Code, existing and proposed regulations and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to "us" or "we" are references to Company and the Operating Partnership.

No attempt has been made in the following discussion to comment on all federal income tax matters affecting us or the unitholders. Moreover, the discussion focuses on unitholders who are individual citizens or residents of the United States and has only limited application to corporations, estates, trusts, nonresident aliens or other unitholders subject to specialized tax treatment, such as tax-exempt institutions, foreign persons, individual retirement accounts (IRAs), real estate investment trusts (REITs)or mutual funds. Accordingly, we recommend that each prospective unitholder consult, and depend on, his own tax advisor in analyzing the federal, state, local and foreign tax consequences particular to him of the ownership or disposition of common units.

All statements as to matters of law and legal conclusions, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of counsel and are based on the accuracy of the representations made by us.

No ruling has been or will be requested from the IRS regarding any matter affecting us or prospective unitholders. An opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made here may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for the common units and the prices at which common units trade. In addition, the costs of any contest with the IRS will be borne directly or indirectly by the unitholders and the General Partner. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

For the reasons described below, counsel has not rendered an opinion with respect to the following specific federal income tax issues:

(1) the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please read "-- Tax Consequences of Unit Ownership -- Treatment of Short Sales");

(2) whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please read "-- Disposition of Common Units -- Allocations Between Transferors and Transferees"); and

(3) whether our method for depreciating Section 743 adjustments is sustainable (please read "-- Tax Consequences of Unit Ownership -- Section 754 Election").

PARTNERSHIP STATUS

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, regardless of whether cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable unless the amount of cash distributed is in excess of the partner's adjusted basis in his partnership interest.

No ruling has been or will be sought from the IRS and the IRS has made no determination as to our status or the status of the Operating Partnership as partnerships for federal income tax purposes or whether our operations generate "qualifying income" under Section 7704 of the Code. Instead, we will rely on the opinion of counsel that, based upon the Internal Revenue Code, its regulations, published revenue rulings and court decisions and the representations described below, we and the Operating Partnership will be classified as a partnership for federal income tax purposes.

In rendering its opinion, counsel has relied on factual representations made by us and the General Partner. The representations made by us and our General Partner upon which counsel has relied are:

(a) Neither we nor the Operating Partnership will elect to be treated as a corporation; and

(b) For each taxable year, more than 90% of our gross income will be income from sources that our counsel has opined or will opine is "qualifying income" within the meaning of Section 7704(d) of the Internal Revenue Code.

Section 7704 of the Internal Revenue Code provides that publicly-traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to as the "Qualifying Income Exception," exists with respect to publicly-traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income and gains derived from the exploration, development, mining or production, processing, refining, transportation and marketing of any mineral or natural resource. Other types of qualifying income include interest other than from a financial business, dividends, gains from the sale of real property and gains from the sale or other disposition of assets held for the production of income that otherwise constitutes qualifying income. We estimate that less than 2% of our current gross income is not qualifying income; however, this estimate could change from time to time. Based upon and subject to this estimate, the factual representations made by us and the General Partner and a review of the applicable legal authorities, counsel is of the opinion that at least 90% of our current gross income constitutes qualifying income.

If we fail to meet the Qualifying Income Exception, other than a failure which is determined by the IRS to be inadvertent and which is cured within a reasonable time after discovery, we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to the unitholders in liquidation of their interests in us. This contribution and liquidation should be tax-free to unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to the unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as either taxable dividend income, to the extent of our current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in his common units, or taxable capital gain, after the unitholder's tax basis in his common units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The discussion below is based on the conclusion that we will be classified as a partnership for federal income tax purposes.

LIMITED PARTNER STATUS

Unitholders who have become limited partners of the Company will be treated as partners of the Company for federal income tax purposes. Also:

(a) assignees who have executed and delivered transfer applications, and are awaiting admission as limited partners, and

(b) unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units,

will be treated as partners of the Company for federal income tax purposes. As there is no direct authority addressing assignees of common units who are entitled to execute and deliver transfer applications and become entitled to direct the exercise of attendant rights, but who fail to execute and deliver transfer applications, counsel's opinion does not extend to these persons. Furthermore, a purchaser or other transferee of common units who does not execute and deliver a transfer application may not receive some federal income tax information or reports furnished to record holders of common units unless the common units are held in a nominee or street name account and the nominee or broker has executed and delivered a transfer application for those common units.

A beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes. Please read "-- Tax Consequences of Unit Ownership -- Treatment of Short Sales."

Income, gain, deductions or losses would not appear to be reportable by a unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for federal income tax purposes would therefore be fully taxable as ordinary income. These holders should consult their own tax advisors with respect to their status as partners in the Company for federal income tax purposes.

TAX CONSEQUENCES OF UNIT OWNERSHIP

Flow-through of Taxable Income. We will not pay any federal income tax. Instead, each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether corresponding cash distributions are received by him. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution. Each unitholder will be required to include in income his allocable share of our income, gains, losses and deductions for our taxable year ending with or within his taxable year.

Treatment of Distributions. Distributions by us to a unitholder generally will not be taxable to the unitholder for federal income tax purposes to the extent of his tax basis in his common units immediately before the distribution. Our cash distributions in excess of a unitholder's tax basis generally will be considered to be gain from the sale or exchange of the common units, taxable in accordance with the rules described under "-- Disposition of Common Units" below. Any reduction in a unitholder's share of our liabilities for which no partner, including the General Partner, bears the economic risk of loss, known as "nonrecourse liabilities," will be treated as a distribution of cash to that unitholder. To the extent our distributions cause a unitholder's "at risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please read "-- Limitations on Deductibility of Losses."

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his tax basis in his common units, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation recapture, and/or substantially appreciated "inventory items," both as defined in the Internal Revenue Code, and collectively, "Section 751 Assets." To that extent, he will be treated as having been distributed his proportionate share of the Section 751 Assets and having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income. That income will equal the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder's tax basis for the share of Section 751 Assets deemed relinquished in the exchange.

Basis of Common Units. A unitholder's initial tax basis for his common units will be the amount he paid for the common units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income and by any increases in his share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by distributions from us, by the unitholder's share of our losses, by any decreases in his share of our nonrecourse liabilities and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A limited partner will have no share of our debt which is recourse to the General Partner, but will have a share, generally based on his share of profits, of our nonrecourse liabilities. Please read "-- Disposition of Common Units -- Recognition of Gain or Loss."

Limitations on Deductibility of Losses. The deduction by a unitholder of his share of our losses will be limited to the tax basis in his units and, in the case of an individual unitholder or a corporate unitholder, if more than 50% of the value of the corporate unitholder's stock is owned directly or indirectly by five or fewer individuals or some tax-exempt organizations, to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than his tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause his at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable to the extent that his tax basis or at risk amount, whichever is the limiting factor, is subsequently increased. Upon the taxable disposition of a unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any excess loss above that gain previously suspended by the at risk or basis limitations is no longer utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by any amount of money he borrows to acquire or hold his units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the units for repayment. A unitholder's at risk amount will increase or decrease as the tax basis of the unitholder's units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

The passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly-traded partnership. Consequently, any passive losses we generate will be available to offset only our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or investments in other publicly-traded partnerships, or salary or active business income. Passive losses that are not deductible because they exceed a unitholder's share of income we generate may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive activity loss rules are applied after other applicable limitations on deductions, including the at risk rules and the basis limitation.

A unitholder's share of our net income may be offset by any suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly-traded partnerships.

Limitations on Interest Deductions. The deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." The IRS has announced that Treasury Regulations will be issued that characterize net passive income from a publicly-traded partnership as investment income for purposes of the limitations on the deductibility of investment interest. In addition, the unitholder's share of our portfolio income will be treated as investment income. Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;

- our interest expense attributed to portfolio income; and

- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment.

Entity-Level Collections. If we are required or elect under applicable law to pay any federal, state or local income tax on behalf of any unitholder or the General Partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the partner on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders. We are authorized to amend the partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under the partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of an individual partner in which event the partner would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction. In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among the General Partner and the unitholders in accordance with their percentage interests in us. At any time that distributions are made to the common units in excess of distributions to the subordinated units, or incentive distributions are made to the General Partner, gross income will be allocated to the recipients to the extent of these distributions. If we have a net loss for the entire year, that loss will be allocated first to the General Partner and the unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts and, second, to the General Partner.

Specified items of our income, gain, loss and deduction will be allocated to account for the difference between the tax basis and fair market value of property contributed to us by the General Partner and its affiliates, referred to in this discussion as "Contributed Property." The effect of these allocations to a unitholder purchasing common units in this offering will be essentially the same as if the tax basis of our assets were equal to their fair market value at the time of this offering. In addition, items of recapture income will be allocated to the extent possible to the partner who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by some unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in an amount and manner to eliminate the negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Internal Revenue Code to eliminate the difference between a partner's "book" capital account, credited with the fair market value of Contributed Property, and "tax" capital account, credited with the tax basis of Contributed Property, referred to in this discussion as the "Book-Tax Disparity", will generally be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction only if the allocation has substantial economic effect. In any other case, a partner's share of an item will be determined on the basis of his interest in us, which will be determined by taking into account all the facts and circumstances, including his relative contributions to us, the interests of all the partners in profits and losses, the interest of all the partners in cash flow and other nonliquidating distributions and rights of all the partners to distributions of capital upon liquidation.

Counsel is of the opinion that, with the exception of the issues described in "-- Tax Consequences of Unit Ownership -- Section 754 Election" and "-- Disposition of Common Units -- Allocations Between Transferors and Transferees," allocations under our partnership agreement will be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction.

Treatment of Short Sales. A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be a partner for those units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period:

- any of our income, gain, loss or deduction with respect to those units would not be reportable by the unitholder;

- any cash distributions received by the unitholder as to those units would be fully taxable; and

- all of these distributions would appear to be ordinary income.

Counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units. The IRS has announced that it is actively studying issues relating to the tax treatment of short sales of partnership interests. Please also read "-- Disposition of Common Units -- Recognition of Gain or Loss."

Alternative Minimum Tax. Each unitholder will be required to take into account his distributive share of any items of our income, gain, loss or deduction for purposes of the alternative minimum tax. The current minimum tax rate for noncorporate taxpayers is 26% on the first $175,000 of alternative minimum taxable income in excess of the exemption amount and 28% on any additional alternative minimum taxable income. Prospective unitholders should consult with their tax advisors as to the impact of an investment in units on their liability for the alternative minimum tax.

Tax Rates. In general the highest effective United States federal income tax rate for individuals for 2001 is 39.6% and the maximum United States federal income tax rate for net capital gains of an individual for 2001 is 20% if the asset disposed of was held for more than 12 months at the time of disposition.

Section 754 Election. We have made the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. The election generally permits us to adjust a common unit purchaser's tax basis in our assets ("inside basis") under Section 743(b) of the Internal Revenue Code to reflect his purchase price. This election does not apply to a person who purchases common units directly from us. The Section 743(b) adjustment belongs to the purchaser and not to other partners. For purposes of this discussion, a partner's inside basis in our assets will be considered to have two components: (1) his share of our tax basis in our assets ("common basis") and (2) his Section 743(b) adjustment to that basis.

Treasury regulations under Section 743 of the Internal Revenue Code require that, if the remedial allocation method is adopted (which we have adopted), a portion of the Section 743(b) adjustment attributable to recovery property be depreciated over the remaining cost recovery period for the Section 704(c) built-in gain. Under Treasury Regulation Section 1.167(c)-l(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Internal Revenue Code rather than cost recovery deductions under Section 168 is generally required to be depreciated using either the straight-line method or the 150% declining balance method. Under our partnership agreement, the General Partner is authorized to take a position to preserve the uniformity of units even if that position is not consistent with these Treasury Regulations. Please read "-- Tax Treatment of Operations -- Uniformity of Units."

Although counsel is unable to opine as to the validity of this approach because there is no clear authority on this issue, we intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of the property, or treat that portion as non-amortizable to the extent attributable to property the common basis of which is not amortizable. This method is consistent with the regulations under Section 743 but is arguably inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6). To the extent this Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. Please read "-- Tax Treatment of Operations -- Uniformity of Units."

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than the units' share of the aggregate tax basis of our assets immediately prior to the transfer. In that case, as a result of the election, the transferee would have, among other items, a greater amount of depreciation and depletion deductions and his share of any gain or loss on a sale of our assets would be less. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his units is lower than those units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or unfavorably by the election.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than he would have been allocated had the election not been revoked.

TAX TREATMENT OF OPERATIONS

Accounting Method and Taxable Year. We use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than one year of our income, gain, loss and deduction. Please read "-- Disposition of Common Units -- Allocations Between Transferors and Transferees."

Initial Tax Basis, Depreciation and Amortization. The tax basis of our assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to this offering will be borne by the General Partner and its affiliates. Please read "-- Allocation of Income, Gain, Loss and Deduction."

To the extent allowable, we may elect to use the depreciation and cost recovery methods that will result in the largest deductions being taken in the early years after assets are placed in service. We are not entitled to any amortization deductions with respect to any goodwill conveyed to us on formation. Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable property by sale, foreclosure, or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a partner who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all, of those deductions as ordinary income upon a sale of his interest in us. Please read "-- Tax Consequences of Unit Ownership -- Allocation of Income, Gain, Loss and Deduction" and "-- Disposition of Common Units -- Recognition of Gain or Loss."

The costs incurred in selling our units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us. The underwriting discounts and commissions we incur will be treated as a syndication cost.

Valuation and Tax Basis of Our Properties. The federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values, and the initial tax bases, of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

DISPOSITION OF COMMON UNITS

Recognition of Gain or Loss. Gain or loss will be recognized on a sale of units equal to the difference between the amount realized and the unitholder's tax basis for the units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received by him plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us in excess of cumulative net taxable income for a common unit that decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder, other than a "dealer" in units, on the sale or exchange of a unit held for more than one year will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of units held more than 12 months will generally be taxed at a maximum rate of 20%. A portion of this gain or loss, which will likely be substantial, however, will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to depreciation recapture or other "unrealized receivables" or to "inventory items" we own. The term "unrealized receivables" includes potential recapture items, including depreciation recapture. Ordinary income attributable to unrealized receivables, inventory items and depreciation recapture may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of units. Net capital loss may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gain in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method. Although the ruling is unclear as to how the holding period of these interests is determined once they are combined, recently finalized regulations allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred. Thus, according to the ruling, a common unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the regulations, may designate specific common units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of common units. A unitholder considering the purchase of additional units or a sale of common units purchased in separate transactions should consult his tax advisor as to the possible consequences of this ruling and application of the final regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;

- an offsetting notional principal contract; or

- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees. In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month (the "Allocation Date"). However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

The use of this method may not be permitted under existing Treasury Regulations. Accordingly, counsel is unable to opine on the validity of this method of allocating income and deductions between unitholders. If this method is not allowed under the Treasury Regulations, or only applies to transfers of less than all of the unitholder's interest, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between unitholders to conform to a method permitted under future Treasury Regulations.

A unitholder who owns units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter but will not be entitled to receive that cash distribution.

Notification Requirements. A unitholder who sells or exchanges units is required to notify us in writing of that sale or exchange within 30 days after the sale or exchange. We are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker. Additionally, a transferor and a transferee of a unit will be required to furnish statements to the IRS, filed with their income tax returns for the taxable year in which the sale or exchange occurred, that describe the amount of the consideration received for the unit that is allocated to our goodwill or going concern value. Failure to satisfy these reporting obligations may lead to the imposition of substantial penalties.

Constructive Termination. We will be considered to have been terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. A constructive termination results in the closing of our taxable year for all unitholders. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. We would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code, and a termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

UNIFORMITY OF UNITS

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of Treasury Regulation Section 1.167(c)-1(a)(6). Any non-uniformity could have a negative impact on the value of the units. Please read "-- Tax Consequences of Unit Ownership -- Section 754 Election."

We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of that property, or treat that portion as nonamortizable, to the extent attributable to property the common basis of which is not amortizable, consistent with the regulations under Section 743, even though that position may be inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6). Please read "-- Tax Consequences of Unit Ownership -- Section 754 Election." To the extent that the Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a depreciation and amortization position under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to a common basis or Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our property. If this position is adopted, it may result in lower annual depreciation and amortization deductions than would otherwise be allowable to some unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. This position will not be adopted if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the unitholders. The IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please read "-- Disposition of Common Units -- Recognition of Gain or Loss."

TAX-EXEMPT ORGANIZATIONS AND OTHER INVESTORS

Ownership of units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations, other foreign persons and regulated investment companies raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them.

Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder which is a tax-exempt organization will be unrelated business taxable income and will be taxable to them.

A regulated investment company or "mutual fund" is required to derive 90%

or more of its gross income from interest, dividends and gains from the sale of stocks or securities or foreign currency or specified related sources. It is not anticipated that any significant amount of our gross income will include that type of income.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the United States because of the ownership of units. As a consequence they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay federal income tax at regular rates on their share of our net income or gain. And, under rules applicable to publicly traded partnerships, we will withhold (currently at the rate of 39.6%) on cash distributions made quarterly to foreign unitholders. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8 or applicable substitute form in order to obtain credit for these withholding taxes.

In addition, because a foreign corporation that owns units will be treated as engaged in a United States trade or business, that corporation may be subject to the United States branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain, as adjusted for changes in the foreign corporation's "U.S. net equity," which are effectively connected with the conduct of a United States trade or business. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a "qualified resident." In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

Under a ruling of the IRS, a foreign unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized on the sale or disposition of that unit to the extent that this gain is effectively connected with a United States trade or business of the foreign unitholder. Apart from the ruling, a foreign unitholder will not be taxed or subject to withholding upon the sale or disposition of a unit if he has owned less than 5% in value of the units during the five-year period ending on the date of the disposition and if the units are regularly traded on an established securities market at the time of the sale or disposition.

ADMINISTRATIVE MATTERS

Information Returns and Audit Procedures. We intend to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine his share of income, gain, loss and deduction. We cannot assure you that those positions will yield a result that conforms to the requirements of the Internal Revenue Code, regulations or administrative interpretations of the IRS. Neither we nor counsel can assure prospective unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his own return. Any audit of a unitholder's return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the "Tax Matters Partner" for these purposes. The partnership agreement names the General Partner as our Tax Matters Partner.

The Tax Matters Partner will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate.

A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting. Persons who hold an interest in us as a nominee for another person are required to furnish to us:

(a) the name, address and taxpayer identification number of the beneficial owner and the nominee;

(b) whether the beneficial owner is

(1) a person that is not a United States person,

(2) a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing, or

(3) a tax-exempt entity;

(c) the amount and description of units held, acquired or transferred for the beneficial owner; and

(d) specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are United States persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Registration as a Tax Shelter. The Internal Revenue Code requires that "tax shelters" be registered with the Secretary of the Treasury. The temporary Treasury Regulations interpreting the tax shelter registration provisions of the Internal Revenue Code are extremely broad. It is arguable that we are not subject to the registration requirement on the basis that we will not constitute a tax shelter. However, the General Partner, as our principal organizer, has registered us as a tax shelter with the Secretary of Treasury because of the absence of assurance that we will not be subject to tax shelter registration and in light of the substantial penalties which might be imposed if registration is required and not undertaken.

ISSUANCE OF THIS REGISTRATION NUMBER DOES NOT INDICATE THAT INVESTMENT IN US OR THE CLAIMED TAX BENEFITS HAVE BEEN REVIEWED, EXAMINED OR APPROVED BY THE IRS.

We must supply our tax shelter registration number to unitholders, and a unitholder who sells or otherwise transfers a unit in a later transaction must furnish the registration number to the transferee. The penalty for failure of the transferor of a unit to furnish the registration number to the transferee is $100 for each failure. The unitholders must disclose our tax shelter registration number on Form 8271 to be attached to the tax return on which any deduction, loss or other benefit we generate is claimed or on which any of our income is included. A unitholder who fails to disclose the tax shelter registration number on his return, without reasonable cause for that failure, will be subject to a $250 penalty for each failure. Any penalties discussed are not deductible for federal income tax purposes.

Accuracy-related Penalties. An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

A substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000 ($10,000 for most corporations). The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

(1) for which there is, or was, "substantial authority," or

(2) as to which there is a reasonable basis and the pertinent facts of that position are disclosed on the return.

More stringent rules apply to "tax shelters," a term that in this context does not appear to include us. If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an "understatement" of income for which no "substantial authority" exists, we must disclose the pertinent facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns to avoid liability for this penalty.

A substantial valuation misstatement exists if the value of any property, or the adjusted basis of any property, claimed on a tax return is 200% or more of the amount determined to be the correct amount of the valuation or adjusted basis. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for most corporations). If the valuation claimed on a return is 400% or more than the correct valuation, the penalty imposed increases to 40%.

STATE, LOCAL AND OTHER TAX CONSIDERATIONS

In addition to federal income taxes, you will be subject to other taxes, including state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on his investment in us. You will be required to file state income tax returns and to pay state income taxes in some or all of the states in which we do business or own property and may be subject to penalties for failure to comply with those requirements. In some states, tax losses may not produce a tax benefit in the year incurred and also may not be available to offset income in subsequent taxable years. Some of the states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the state, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. Please read "-- Tax Consequences of Unit Ownership -- Entity-Level Collections." Based on current law and our estimate of our future operations, the General Partner anticipates that any amounts required to be withheld will not be material. We may also own property or do business in other states in the future.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent states and localities, of his investment in us. Accordingly, each prospective unitholder should consult, and must depend upon, his own tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state and local, as well as United States federal tax returns, that may be required of him. Counsel has not rendered an opinion on the state or local tax consequences of an investment in us.

TAX CONSEQUENCES OF OWNERSHIP OF DEBT SECURITIES

A description of the material federal income tax consequences of the acquisition, ownership and disposition of debt securities will be set forth in the prospectus supplement relating to the offering of debt securities.

SELLING UNITHOLDERS

In addition to covering our offering of securities, this Prospectus covers the offering for resale of an unspecified number of common units by selling unitholders. The applicable prospectus supplement will set forth, with respect to each selling unitholder,

(1) the name of the selling unitholder,

(2) the nature of any position, office or other materials relationship which the selling unitholder will have had within the prior three years with us or any of our predecessors or affiliates,

(3) the number of common units owned by the selling unitholders prior to the offering,

(4) the amount of common units to be offered for the selling unitholder's account, and

(5) the amount and (if one percent or more) the percentage of the common units to be owned by the selling unitholders after completion of the offering.

PLAN OF DISTRIBUTION

We may sell the common units or debt securities directly, through agents, or to or through underwriters or dealers. Please read the prospectus supplement to find the terms of the common unit or debt securities offering including:

- the names of any underwriters, dealers or agents;
- the offering price;
- underwriting discounts;
- sales agents' commissions;
- other forms of underwriter or agent compensation;
- discounts, concessions or commissions that underwriters may pass on to other dealers;
- any exchange on which the common units or debt securities are listed.

We may change the offering price, underwriter discounts or concessions, or the price to dealers when necessary. Discounts or commissions received by underwriters or agents and any profits on the resale of common units or debt securities by them may constitute underwriting discounts and commissions under the Securities Act of 1933.

Unless we state otherwise in the prospectus supplement, underwriters will need to meet certain requirements before purchasing common units or debt securities. Agents will act on a "best efforts" basis during their appointment. We will also state the net proceeds from the sale in the prospectus supplement.

Any brokers or dealers that participate in the distribution of the common units or debt securities may be "underwriters" within the meaning of the Securities Act of 1933 (the "Securities Act") for such sales. Profits, commissions, discounts or concessions received by such broker or dealer may be underwriting discounts and commissions under the securities act.

When necessary, we may fix common unit or debt securities distribution using changeable, fixed prices, market prices at the time of sale, prices related to market prices, or negotiated prices.

We may, through agreements, indemnify underwriters, dealers or agents who participate in the distribution of the common units or debt securities against certain liabilities including liabilities under the Securities Act. We may also provide funds for payments such underwriters, dealers or agents may be required to make. Underwriters, dealers and agents, and their affiliates may transact with us and our affiliates in the ordinary course of their business.

DISTRIBUTION BY SELLING UNITHOLDERS

Distribution of any common units to be offered by one or more of the selling unitholders may be effected from time to time in one or more transactions (which may involve block transactions) (1) on the New York Stock Exchange, (2) in the over-the-counter market, (3) in underwritten transactions; (4) in transactions otherwise than on the New York Stock Exchange or in the over-the-counter market or (5) in a combination of any of these transactions. The transactions may be effected by the selling unitholders at market prices prevailing at the time of sale, at prices related to the prevailing market prices, at negotiated prices or at fixed prices. The selling unitholders may offer their shares through underwriters, brokers, dealers or agents, who may receive compensation in the form of underwriting discounts, commissions or concessions from the selling unitholders and/or the purchasers of the shares for whom they act as agent. The selling unitholders may engage in short sales, short sales against the box, puts and calls and other transactions in our securities, or derivatives thereof, and may sell and deliver their common units in connection therewith. In addition, the selling unitholders may from time to time sell their common units in transactions permitted by Rule 144 under the Securities Act.

As of the date of this prospectus, we have not engaged any underwriter, broker, dealer or agent in connection with the distribution of common units pursuant to this prospectus by the selling unitholders. To the extent required, the number of common units to be sold, the purchase price, the name of any applicable agent, broker, dealer or underwriter and any applicable commissions with respect to a particular offer will be set forth in the applicable prospectus supplement. The aggregate net proceeds to the selling unitholders from the sale of their common units offered hereby will be the sale price of those shares, less any commissions, if any, and other expenses of issuance and distribution not borne by us.

The selling unitholders and any brokers, dealers, agents or underwriters that participate with the selling unitholders in the distribution of shares may be deemed to be "underwriters" within the meaning of the Securities Act, in which event any discounts, concessions and commissions received by such brokers, dealers, agents or underwriters and any profit on the resale of the shares purchased by them may be deemed to be underwriting discounts and commissions under the Securities Act.

The applicable prospectus supplement will set forth the extent to which we will have agreed to bear fees and expenses of the selling unitholders in connection with the registration of the common units being offered hereby by them. We may, if so indicated in the applicable prospectus supplement, agree to indemnify selling unitholders against certain civil liabilities, including liabilities under the Securities Act.

LEGAL MATTERS

Vinson & Elkins L.L.P., our counsel, will issue an opinion for us about the legality of the common units and debt securities and the material federal income tax considerations regarding the common units. Any underwriter will be advised about other issues relating to any offering by their own legal counsel.

EXPERTS

The consolidated financial statements and the related consolidated financial statement schedules incorporated in this prospectus by reference from Enterprise Products Partners L.P.'s and Enterprise Products Operating L.P.'s respective Annual Reports on Form 10-K for the years ended December 31, 2000 and 1999 have been audited by Deloitte & Touche LLP, independent auditors, as stated in their reports, which are incorporated herein by reference, and have been so incorporated in reliance upon the reports of such firm given upon their authority as experts in accounting and auditing.

9,300,000 COMMON UNITS
REPRESENTING LIMITED PARTNER INTERESTS

[ENTERPRISE PRODUCTS PARTNERS L.P. LOGO]

ENTERPRISE PRODUCTS PARTNERS L.P.

PROSPECTUS SUPPLEMENT
, 2002

LEHMAN BROTHERS

GOLDMAN, SACHS & CO.

UBS WARBURG

RBC CAPITAL MARKETS

WACHOVIA SECURITIES

MCDONALD INVESTMENTS

RAYMOND JAMES

SANDERS MORRIS HARRIS