ENTERPRISE PRODUCTS PARTNERS L P
Form 424B2
October 03, 2002

FILED PURSUANT TO RULE 424B2
REGISTRATION NO. 333-56082

PROSPECTUS SUPPLEMENT
(TO PROSPECTUS DATED MARCH 27, 2001)

[ENTERPRISE PRODUCTS PARTNERS L.P. LOGO]

ENTERPRISE PRODUCTS PARTNERS L.P.

9,800,000 COMMON UNITS

REPRESENTING LIMITED PARTNER INTERESTS

We are offering to sell 9,800,000 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 October 2, 2002 was $18.99 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	$18.99	$186,102,000
Underwriting discount (1)	$ 0.81	$ 6,472,548
Proceeds to Enterprise Products Partners (before expenses)	$18.18	$179,629,452

----
(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 9,200 common units to other members of our senior management.

We have granted the underwriters a 30-day option to purchase up to 1,470,000 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 October 8, 2002.

LEHMAN BROTHERS
GOLDMAN, SACHS & CO.

UBS WARBURG
RBC CAPITAL MARKETS
WACHOVIA SECURITIES
MCDONALD INVESTMENTS INC.
RAYMOND JAMES
SANDERS MORRIS HARRIS

October 2, 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 $251.7 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 21.8% 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 29,085,964 publicly held common units outstanding, representing a 15.5% limited partner interest in us;

- EPCO and its affiliated entities will own 81,608,802 common units and 32,114,804 subordinated units representing an aggregate 60.7% limited partner interest in us;

- Shell will own 31,000,000 common units and 10,000,000 special units representing a 21.8% 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	29,085,964	15.5%
EPCO common units	81,608,802	43.6%
EPCO subordinated units	32,114,804	17.1%
Shell common units	31,000,000	16.5%
Shell special units	10,000,000	5.3%
General partner interest (70% EPCO; 30% Shell)(1)		2.0%
Total		100.0%

[GRAPH]

----

(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	9,800,000 common units, including 1,809,200 common units to be offered to members of our senior management or their affiliates; and 11,270,000 common units if the underwriters exercise their over-allotment option in full.
Units outstanding after this offering	141,694,766 common units or 143,164,766 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				
FOR THE YEAR ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
1999	2000	2001	2001	200

(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
Equity in income of unconsolidated affiliates	13,477	24,119	25,358	11,061	16
Total	$1,346,456	$3,073,139	$3,179,727	$1,806,773	$1,464
Costs and expenses:					
Operating costs and expenses	$1,201,605	$2,801,060	$2,861,743	$1,629,380	$1,410
Selling, general and administrative expenses	12,500	28,345	30,296	13,905	15
Total	$1,214,105	$2,829,405	$2,892,039	$1,643,285	$1,425
Operating income	$ 132,351	$ 243,734	$ 287,688	$ 163,488	$ 38
Other income (expense):					
Interest expense	$ (16,439)	$ (33,329)	$ (52,456)	$ (23,318)	$ (37
Interest income from unconsolidated affiliates	1,667	1,787	31	31	
Dividend income from unconsolidated affiliates	3,435	7,091	3,462	1,632	2
Interest income -- other	886	3,748	7,029	5,477	1
Other income (expense), net	(379)	(272)	(1,104)	(531)	
Total	$ (10,830)	$ (20,975)	$ (43,038)	$ (16,709)	$ (33
Income before income taxes and minority interest	$ 121,521	$ 222,759	$ 244,650	$ 146,779	$ 5
Provision for income taxes	--	--	--	--	
Income before minority interest	$ 121,521	$ 222,759	$ 244,650	$ 146,779	$ 5
Minority interest	(1,226)	(2,253)	(2,472)	(1,478)	
Net income	$ 120,295	$ 220,506	$ 242,178	$ 145,301	$ 5
BASIC EARNINGS PER UNIT(1):					
Net income per common and subordinated unit	$ 0.90	$ 1.63	$ 1.70	$ 1.06	$
DILUTED EARNINGS PER UNIT(1):					
Net income per common, subordinated and special unit	$ 0.82	$ 1.32	$ 1.39	$ 0.85	$
BALANCE SHEET DATA (AT PERIOD END):					
Total assets	$1,494,952	$1,951,368	$2,431,193	$2,441,993	$2,792
Total debt	295,000	403,847	855,278	855,608	1,223
Partners' equity	789,465	935,959	1,146,922	1,000,704	1,045
OTHER FINANCIAL DATA:					
Cash flows from (used in) operating activities	$ 177,953	$ 360,870	$ 283,328	$ 90,595	$ 45
Cash flows from (used in) investing activities	(271,229)	(268,798)	(491,213)	(397,474)	(431
Cash flows from (used in) financing activities	74,403	(36,893)	279,547	362,428	257
EBITDA	147,050	267,058	320,392	180,349	60
Distributions received from unconsolidated affiliates	6,008	37,267	45,054	13,212	29
OPERATING DATA (IN MBPD, EXCEPT AS NOTED):					
Pipelines:					
Major NGL and petrochemical					

pipelines	264	367	454	430	
Natural gas pipelines (BBtu/d)	n/a	n/a	1,349	1,263	1
Fractionation:					
NGL fractionation	184	213	204	184	
Isomerization	74	74	80	82	
Propylene fractionation	28	33	31	30	
Processing -- equity NGL production	67	72	63	54	
Octane enhancement	5	5	5	4	

----

(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 prior to giving effect to this offering, 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.

S-10

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 $178.6 million from the sale of the 9,800,000 common units after deducting underwriting discounts and commissions and estimated offering expenses. In connection with the offering, we also will receive a capital contribution of $3.8 million from our general partner to maintain its combined 2% general partner interest. The underwriters will receive no discount or commission on the sale of 1,809,200 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 $209.7 million, including the $4.4 million general partner proportionate contribution.

We will use the net proceeds of this offering 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. We will use the proceeds from the general partner's capital contribution for the repayment of debt. At October 2, 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 October 2, 2002 was $18.99 per common unit.

	PRICE RANGES(1)		CASH DISTRIBUTION HISTORY		
	HIGH	LOW	PER UNIT(1)(2)	RECORD DATE	PAYM DAT
2000					
1st Quarter	$10.44	$ 9.13	$0.2500	Apr. 28, 2000	May 10
2nd Quarter	11.38	9.75	0.2625	Jul. 31, 2000	Aug. 10
3rd Quarter	14.47	11.07	0.2625	Oct. 31, 2000	Nov. 10
4th Quarter	15.94	11.75	0.2750	Jan. 31, 2001	Feb. 9
2001					

1st Quarter............................	$18.40	$13.25	$0.2750	Apr. 30, 2001	May 10
2nd Quarter............................	21.88	16.60	0.2938	Jul. 31, 2001	Aug. 10
3rd Quarter............................	24.18	19.75	0.3125	Oct. 31, 2001	Nov. 9
4th Quarter............................	26.30	21.80	0.3125	Jan. 31, 2002	Feb. 11
2002					
1st Quarter............................	$25.57	$23.13	$0.3350	Apr. 30, 2002	May 10
2nd Quarter............................	24.43	16.25	0.3350	Jul. 31, 2002	Aug. 12
3rd Quarter............................	22.00	16.75			
4th Quarter (through October 2, 2002)....	19.28	18.99			

----

(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 ADJUSTE
		(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	$1,021,371
Seminole debt, current maturities (1).................	--	15,000	15,000
Long-term debt:			
364-Day Credit Facility, due November 2002 (2).........	138,000	148,000	144,355

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	$2,309,726
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	$2,311,278
Minority interest......................................	10,818	65,146	66,987
Partners' equity:			
Common units...	$ 589,504	$ 589,504	$ 768,133
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	12,430
Total partners' equity.............................	$1,045,846	$1,045,846	$1,226,279
Total capitalization...................................	$2,280,216	$3,604,544	$3,604,544

----

(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				
	FOR THE YEAR ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	1999	2000	2001	2001	200
				(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
Equity in income of unconsolidated affiliates	13,477	24,119	25,358	11,061	16
Total	$1,346,456	$3,073,139	$3,179,727	$1,806,773	$1,464
Costs and expenses:					
Operating costs and expenses	$1,201,605	$2,801,060	$2,861,743	$1,629,380	$1,410
Selling, general and administrative expenses	12,500	28,345	30,296	13,905	15

Total	$1,214,105	$2,829,405	$2,892,039	$1,643,285	$1,425
Operating income	$ 132,351	$ 243,734	$ 287,688	$ 163,488	$ 38
Other income (expense):					
Interest expense	$ (16,439)	$ (33,329)	$ (52,456)	$ (23,318)	$ (37
Interest income from unconsolidated affiliates	1,667	1,787	31	31	
Dividend income from unconsolidated affiliates	3,435	7,091	3,462	1,632	2
Interest income -- other	886	3,748	7,029	5,477	1
Other income (expense), net	(379)	(272)	(1,104)	(531)	
Total	$ (10,830)	$ (20,975)	$ (43,038)	$ (16,709)	$ (33
Income before income taxes and minority interest	$ 121,521	$ 222,759	$ 244,650	$ 146,779	$ 5
Provision for income taxes	--	--	--	--	
Income before minority interest	$ 121,521	$ 222,759	$ 244,650	$ 146,779	$ 5
Minority interest	(1,226)	(2,253)	(2,472)	(1,478)	
Net income	$ 120,295	$ 220,506	$ 242,178	$ 145,301	$ 5
BASIC EARNINGS PER UNIT(1):					
Net income per common and subordinated unit	$ 0.90	$ 1.63	$ 1.70	$ 1.06	$
DILUTED EARNINGS PER UNIT(1):					
Net income per common, subordinated and special unit	$ 0.82	$ 1.32	$ 1.39	$ 0.85	$
BALANCE SHEET DATA (AT PERIOD END):					
Total assets	$1,494,952	$1,951,368	$2,431,193	$2,441,993	$2,792
Total debt	295,000	403,847	855,278	855,608	1,223
Partners' equity	789,465	935,959	1,146,922	1,000,704	1,045
OTHER FINANCIAL DATA:					
Cash flows from (used in) operating activities	$ 177,953	$ 360,870	$ 283,328	$ 90,595	$ 45
Cash flows from (used in) investing activities	(271,229)	(268,798)	(491,213)	(397,474)	(431
Cash flows from (used in) financing activities	74,403	(36,893)	279,547	362,428	257
EBITDA	147,050	267,058	320,392	180,349	60
Distributions received from unconsolidated affiliates	6,008	37,267	45,054	13,212	29
OPERATING DATA (IN MBPD, EXCEPT AS NOTED):					
Pipelines:					
Major NGL and petrochemical pipelines	264	367	454	430	
Natural gas pipelines (BBtu/d)	n/a	n/a	1,349	1,263	1
Fractionation:					
NGL fractionation	184	213	204	184	
Isomerization	74	74	80	82	
Propylene fractionation	28	33	31	30	
Processing -- equity NGL production	67	72	63	54	
Octane enhancement	5	5	5	4	

----

(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,		
	1999	2000	2001
(Dollars in thousands)			
INCOME STATEMENT DATA:			
Revenues	$ 190,686	$209,895	$214,518
Costs and expenses:			
Operating costs and expenses	87,623	105,591	125,349
Selling, general and administrative expenses	28,718	29,307	28,364
Total	116,341	134,898	153,713
Operating income	74,345	74,997	60,805
Other income (expense):			
Interest expense	(7,673)	(13,500)	(12,700)
Other, net	822	880	(1,035)
Total	(6,851)	(12,620)	(13,735)
Income before income taxes	67,494	62,377	47,070
Provision for income taxes	(23,651)	(22,826)	(17,445)
Net income	$ 43,843	$ 39,551	$ 29,625
BALANCE SHEET DATA (AT PERIOD END):			
Total assets		$736,783	$710,835
Long-term debt		90,000	90,000
Owner equity		358,184	387,809
OTHER FINANCIAL DATA:			
Cash flows from (used in) operating activities	$ 124,367	$ 20,724	$ 17,893
Cash flows from (used in) investing activities	(124,367)	(20,724)	(17,893)
EBITDA	94,187	100,877	84,771

SEMINOLE PIPELINE COMPANY

	HISTORICAL		
	FOR THE YEAR ENDED DECEMBER 31,		
	1999	2000	2001

(Dollars in thousands)

INCOME STATEMENT DATA:			
Revenues	$ 64,210	$ 66,609	$ 65,800
Costs and expenses:			
Operating costs and expenses	27,278	37,293	33,539
Selling, general and administrative expenses	1,035	1,700	1,535
Total	28,313	38,993	35,074
Operating income	35,897	27,616	30,726
Other income (expense):			
Interest expense	(5,002)	(5,003)	(5,160)
Other, net	670	(1,542)	662
Total	(4,332)	(6,545)	(4,498)
Income before income taxes	31,565	21,071	26,228
Provision for income taxes	(11,611)	(7,590)	(9,470)
Net income	$ 19,954	$ 13,481	$ 16,758
BALANCE SHEET DATA (AT PERIOD END):			
Total assets		$280,940	$282,399
Long-term debt, including current maturities		75,000	60,000
Owner equity		121,125	133,083
OTHER FINANCIAL DATA:			
Cash flows from (used in) operating activities	$ 19,248	$ 35,046	$ 25,343
Cash flows from (used in) investing activities	(1,946)	(795)	(565)
Cash flows from (used in) financing activities	(24,000)	(31,590)	(19,800)
EBITDA	46,692	36,257	41,587

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.

S-23

- 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	FOR YEAR ENDED DECEMBER 31, 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	FOR YEAR ENDED DECEMBER 31, 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.

S-27

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.

S-28

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 p