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

FORM 8-K

CURRENT REPORT

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

Date of Report (Date of earliest event reported): May 15, 2002

ENTERPRISE PRODUCTS PARTNERS L.P.
(Exact name of registrant as specified in its charter)

Delaware	1-14323	76-0568219
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification Number)

2727 North Loop West Houston, Texas	77008
(Address of principal executive offices)	(Zip Code)

(713) 880-6500
(Registrants' telephone number, including area code)

ITEM 5. OTHER EVENTS.

On May 15, 2002, Enterprise Products Partners L.P. completed a two-for-one split of its Common Units, Subordinated Units and Class A Special Units. Accordingly, Enterprise is revising its consolidated financial statements and the notes thereto to retroactively reflect the effects of the two-for-one split.

ITEM 7. FINANCIAL STATEMENTS AND EXHIBITS.

(a) FINANCIAL STATEMENTS OF BUSINESS ACQUIRED.

Not applicable.

(b) PRO FORMA FINANCIAL INFORMATION.

Not applicable.

(c) EXHIBITS.

23.1 Consent of Deloitte & Touche LLP

99.1 Enterprise Products Partners L.P. Audited Annual Financial Statements for the fiscal year ended December 31, 2001, as revised to retroactively reflect the effects of a May 15, 2002 two-for-one split of its Common Units, Subordinated Units and Class A Special Units.

SIGNATURES

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

ENTERPRISE PRODUCTS PARTNERS L.P.

By: Enterprise Products GP, LLC,
as General Partner

Date: September 27, 2002

By: /s/ Michael J. Knesek

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

EXHIBIT INDEX

EXHIBIT NUMBER	EXHIBIT DESCRIPTION
23.1	Consent of Deloitte & Touche LLP
99.1	Enterprise Products Partners L.P. Audited Annual Financial Statements

EXHIBIT 23.1

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in the Registration Statement (Form S-3 No. 333-56082) and related Prospectus of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. and in the Registration Statement (Form S-8 No. 333-36856) pertaining to Enterprise Products Company 1998 Long-Term Executive Plan and Enterprise Products GP, LLC 1999 Long-Term Executive Plan and in the Registration Statement (Form S-8 No. 333-92486) pertaining to the Enterprise Products Company Employee Unit Purchase Plan of our report dated March 8, 2002 (May 15, 2002 as to Note 16 for the effects of a two-for-one split of Limited Partner Units) (which report expresses an unqualified opinion and includes an explanatory paragraph referring to the change in accounting for derivative instruments in 2001), with respect to the consolidated financial statements of Enterprise Products Partners L.P. included in this Current Report on Form 8-K dated September 27, 2002.

/s/ Deloitte & Touche LLP

Houston, Texas
September 27, 2002

EXHIBIT 99.1

INDEPENDENT AUDITORS' REPORT

Enterprise Products Partners L.P.:

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2001 and 2000, and the related statements of consolidated operations, consolidated cash flows and consolidated partners' equity for each of the years in the three-year period ended December 31, 2001. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2001 and 2000, and the results of its consolidated operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

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

/s/ DELOITTE & TOUCHE LLP

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

ENTERPRISE PRODUCTS PARTNERS L.P.

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

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

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS
(DOLLARS IN THOUSANDS)

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

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

STATEMENTS OF CONSOLIDATED CASH FLOWS
(DOLLARS IN THOUSANDS)

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

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(DOLLARS IN THOUSANDS)

	LIMITED PARTNERS					
	COMMON UNITS	SUBORD. UNITS	SPECIAL UNITS	TREASURY UNITS	GENERAL PARTNER	TOTAL
Balance, December 31, 1998	$ 433,082	$123,829			$ 5,625	$ 562,536
Net income	80,998	38,094			1,203	120,295
Leases paid by EPCO	7,109	3,342			106	10,557
Special Units issued to Shell in connection with TNGL acquisition			$210,436		2,126	212,562
Cash distributions to Unitholders	(81,993)	(28,647)			(1,118)	(111,758)
Treasury Units acquired by consolidated Trust				$(4,727)		(4,727)
Balance, December 31, 1999	439,196	136,618	210,436	(4,727)	7,942	789,465
Net income	148,656	69,253			2,597	220,506
Leases paid by EPCO	7,117	3,315			105	10,537
Additional Special Units issued to Shell in connection with contingency agreement			55,241		557	55,798
Conversion of 2.0 million Shell Special Units into Common Units	14,513		(14,513)			--
Units repurchased and retired in connection with buy-back program	(687)	(43)	(32)		(8)	(770)
Cash distributions to Unitholders	(93,899)	(43,890)			(1,788)	(139,577)
Balance, December 31, 2000	514,896	165,253	251,132	(4,727)	9,405	935,959
Net income	163,795	72,775			5,608	242,178
Leases paid by EPCO	7,078	3,128			103	10,309
Additional Special Units issued to Shell in connection with contingency agreement			117,066		1,183	118,249
Conversion of 10.0 million Shell Special Units into Common Units	72,554		(72,554)			
Cash distributions to Unitholders	(109,969)	(49,510)			(4,829)	(164,308)
Treasury Units acquired by consolidated Trust				(18,003)		(18,003)
Treasury Units reissued by consolidated Trust				16,508		16,508
Gain on reissuance of Treasury Units by consolidated Trust	3,518	1,461	990		61	6,030
Balance, December 31, 2001	$ 651,872	$193,107	$296,634	$(6,222)	$11,531	$1,146,922

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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

Under terms of a contract entered into on May 8, 1998 between EPCO and our Operating Partnership, EPCO contributed all of its NGL assets through the Company and the General Partner to the Operating Partnership and the Operating Partnership assumed certain of EPCO's debt. As a result, we became the successor to the NGL operations of EPCO.

Effective July 27, 1998, we filed a registration statement pursuant to an initial public offering of 24,000,000 Common Units. The Common Units sold for $11 per unit. We received approximately $243.3 million net of underwriting commissions and offering costs.

The accompanying consolidated financial statements include the historical accounts and operations of the NGL business of EPCO, including NGL operations conducted by affiliated companies of EPCO prior to their consolidation with EPCO. The consolidated financial statements include our accounts and those of our majority-owned subsidiaries, after elimination of all material intercompany accounts and transactions. In general, investments in which we own 20% to 50% and exercise significant influence over operating and financial policies are accounted for using the equity method. Investments in which we own less than 20% are accounted for using the cost method unless we exercise significant influence over operating and financial policies of the investee in which case the investment is accounted for using the equity method.

Certain reclassifications have been made to the prior years' financial statements to conform to the current year presentation. These reclassifications had no effect on previously reported results of consolidated operations.

CASH FLOWS are computed using the indirect method. For cash flow purposes, we consider all highly liquid investments with an original maturity of less than three months at the date of purchase to be cash equivalents.

FINANCIAL INSTRUMENTS such as swaps, forwards and other contracts to manage the price risks associated with inventories, firm commitments and certain anticipated transactions are used by the Company. We are required to recognize in earnings changes in fair value of these financial instruments that are not offset by changes in the fair value of the inventories, firm commitments and certain anticipated transactions. Fair value is generally defined as the amount at which the financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale.

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

DOLLAR AMOUNTS (except per Unit amounts) presented in the tabulations within the notes to our financial statements are stated in thousands of dollars, unless otherwise indicated.

EARNINGS PER UNIT is based on the amount of income allocated to limited partners and the weighted-average number of Units outstanding during the period. Specifically, basic earnings per Unit is calculated by dividing the amount of income allocated to limited partners by the weighted-average number of Common and Subordinated Units outstanding during the period. Diluted earnings per Unit is based on the amount of income allocated to limited partners and the weighted-average number of Common, Subordinated and Special Units outstanding during the period. The Special Units are excluded from the computation of basic earnings per Unit because, under the terms of the Special Units, they do not share in income nor are they entitled to cash distributions until they are converted to Common Units. See Notes 7 and 8 for additional information on the capital structure and earnings per Unit computation.

ENVIRONMENTAL COSTS for remediation are accrued based on the estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate costs to remediate the site. Ongoing environmental compliance costs are charged to expense as incurred, and expenditures to mitigate or prevent future environmental contamination are capitalized. Environmental costs, accrued environmental liabilities and expenditures to mitigate or eliminate future environmental contamination for each of the years in the three-year period ended December 31, 2001 were not significant to the consolidated financial statements. Costs of environmental compliance and monitoring aggregated $1.3 million, $1.3 million and $0.9 million for the years ended December 31, 2001, 2000 and 1999, respectively. Our estimated liability for environmental remediation is not discounted.

EXCESS COST OVER UNDERLYING EQUITY IN NET ASSETS (or "excess cost") denotes the excess of our cost (or purchase price) over our underlying equity in the net assets of our investees. We have excess cost associated with our investments in K/D/S Promix L.L.C., Dixie Pipeline Company, Neptune Pipeline Company L.L.C. and Nemo Pipeline Company, LLC. The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. See Note 4 for a further discussion of the excess cost related to these investments.

EXCHANGES are movements of NGL and petrochemical products and natural gas between parties to satisfy timing and logistical needs of the parties. Volumes borrowed from us under such agreements are included in inventory, and volumes loaned to us under such agreements are accrued as a liability in accrued gas payables.

FEDERAL INCOME TAXES are not provided because we are a master limited partnership. As a result, our earnings or losses for Federal income tax purposes are included in the tax returns of the individual partners. Accordingly, no recognition has been given to income taxes in our financial statements. State income taxes are not material to us. Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under the partnership agreement.

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

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

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

LONG-LIVED ASSETS are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. We have not recognized any impairment losses for any of the periods presented.

PROPERTY, PLANT AND EQUIPMENT is recorded at cost and is depreciated using the straight-line method over the asset's estimated useful life. Maintenance, repairs and minor renewals are charged to operations as incurred. The cost of assets retired or sold, together with the related accumulated depreciation, is removed from the accounts, and any gain or loss on disposition is included in income.

Additions and improvements to and major renewals of existing assets are capitalized and depreciated using the straight-line method over the estimated useful life of the new equipment or modifications. These expenditures result in a long-term benefit to the Company. We generally classify improvements and major renewals of existing assets as sustaining capital expenditures and all other capital spending on existing and new assets referred to as expansion capital expenditures.

RESTRICTED CASH includes amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for physical purchase transactions made on the NYMEX exchange. At December 31, 2001, cash and cash equivalents includes $5.8 million of restricted cash related to these requirements.

REVENUE is recognized by our five reportable business segments using the following criteria: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer's price is fixed or determinable and (iv) collectibility is reasonably assured. When the contracts settle (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), a determination of the necessity of an allowance is made and recorded accordingly.

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

In our Pipelines segment, we enter into pipeline, storage and product loading contracts. Under our liquids pipeline and certain natural gas pipeline throughput contracts, revenue is recognized when volumes have been physically delivered for the customer through the pipeline. Revenue from this type of throughput contract is typically based upon a fixed fee per gallon of liquids or MMBtus of natural gas transported, whichever the case may be, multiplied by the volume delivered. The throughput fee is generally contractual or as regulated by the Federal Energy Regulatory Commission ("FERC"). Additionally, we have merchant contracts associated with our natural gas pipeline business whereby revenue is recognized once a quantity of natural gas has been delivered to a customer. These merchant contracts are based upon market-related prices as determined by the individual contracts.

In our storage contracts, we collect a fee based on the number of days a customer has NGL or petrochemical volumes in storage multiplied by a storage rate for each product. Under these contracts, revenue is recognized ratably over the length of the storage contract based on the storage rates specified in each contract. Revenues from product loading contracts (applicable to EPIK, an unconsolidated affiliate of the Company) are recorded once the loading services have been performed with the loading rates stated in the individual contracts.

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

Under these contracts, the fee for our natural gas processing services is based upon contractual terms with Shell or other third parties and may be specified as either a cash fee or the retention of a percentage of the NGLs extracted from the natural gas stream. If a cash fee for services is stipulated by the contract, we record revenue once the natural gas has been processed and sent back to Shell or other third parties (i.e., delivery has taken place).

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

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

The Other segment is primarily comprised of fee-based marketing services. We perform NGL marketing services for a small number of customers for which we charge a commission. Commissions are based on either a percentage of the final sales price negotiated on behalf of the client or a fixed-fee per gallon based on the volume sold for the client. Revenues are recorded at the time the services are complete.

USE OF ESTIMATES AND ASSUMPTIONS by management that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period are required for the preparation of financial statements in conformity with accounting principles generally accepted in the United States of America. Our actual results could differ from these estimates.

2. BUSINESS ACQUISITIONS

ACQUISITION OF ACADIAN GAS IN APRIL 2001

On April 2, 2001, we acquired Acadian Gas from an affiliate of Shell, for approximately $226 million in cash using proceeds from the issuance of the $450 million Senior Notes B (see Note 6). Acadian Gas is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. Its assets are comprised of the 438-mile Acadian and 577-mile Cypress natural gas pipelines and a leased natural gas storage facility. Acadian Gas owns an approximate 49.5% of Evangeline which owns a 27-mile natural gas pipeline. We operate the systems. Overall, the Acadian Gas and Evangeline systems are comprised of 1,042 miles of pipeline with an optimal design capacity of 1.1 Bcf/d.

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

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

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

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

PRO FORMA EFFECT OF BUSINESS COMBINATIONS

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

The pro forma information is based upon data currently available to and certain estimates and assumptions by management and, as a result, are not necessarily indicative of our financial results had the transactions actually occurred on these dates. Likewise, the unaudited pro forma information is not necessarily indicative of our future financial results.

	FOR YEAR ENDED DECEMBER 31, 2001	2000
Revenues	$3,391,654	$3,673,049
Income before extraordinary item and minority interest	$ 248,934	$ 217,223
Net income	$ 246,419	$ 215,026
Allocation of net income to Limited partners	$ 240,745	$ 212,483
General Partner	$ 5,674	$ 2,542
Units used in earnings per Unit calculations		
Basic	139,452	134,216
Diluted	170,786	164,888
Income per Unit before minority interest		
Basic	$ 1.75	$ 1.60
Diluted	$ 1.43	$ 1.30
Net income per Unit		
Basic	$ 1.73	$ 1.59
Diluted	$ 1.41	$ 1.29

3. PROPERTY, PLANT AND EQUIPMENT

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

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

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

4. INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES

We own interests in a number of related businesses that are accounted for under the equity or cost method. The investments in and advances to these unconsolidated affiliates are grouped according to the operating segment to which they relate. For a general discussion of our operating segments, see Note 15.

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

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

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

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

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

FRACTIONATION SEGMENT:

At December 31, 2001, the Fractionation segment included the following unconsolidated affiliates accounted for using the equity method:

- Baton Rouge Fractionators LLC ("BRF") -- an approximate 32.25% interest in an NGL fractionation facility located in southeastern Louisiana.

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

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

The combined balance sheet information for the last two years and results of operations data for the last three years of the Fractionation segment's equity method investments are summarized below. As used in the following tables, gross operating margin for equity investments represents operating income before depreciation and amortization expense (both on operating assets) and selling, general and administrative costs.

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

PIPELINES SEGMENT:

At December 31, 2001, our Pipelines operating segment included the following unconsolidated affiliates accounted for using the equity method:

- EPIK Terminalling L.P. and EPIK Gas Liquids, LLC (collectively, "EPIK") -- a 50% aggregate interest in a refrigerated NGL marine terminal loading facility located in southeast Texas. The Company owns 50% of EPIK Terminalling L.P. which owns 99% of such facilities. We own 50% of EPIK Gas Liquids, LLC which owns 1% of such facilities. We do not exercise control over these entities; therefore, we are precluded from consolidating such entities into our financial statements.

- Wilprise Pipeline Company, LLC ("Wilprise") -- a 37.35% interest in an NGL pipeline system located in southeastern Louisiana.

- Tri-States NGL Pipeline LLC ("Tri-States") -- an aggregate 33.33% interest in an NGL pipeline system located in Louisiana, Mississippi and Alabama.

- Belle Rose NGL Pipeline LLC ("Belle Rose") -- a 41.67% interest in an NGL pipeline system located in south Louisiana.

- Dixie Pipeline Company ("Dixie") -- an aggregate 19.88% interest in a 1,301-mile propane pipeline and associated facilities extending from Mont Belvieu, Texas to North Carolina. Our investment includes excess cost over the underlying equity in the net assets of Dixie of $37.4 million. The excess cost, which relates to pipeline assets, is being amortized against our share of Dixie's earnings over a period of 35 years, which is the estimated useful life of the pipeline assets that gave rise to the difference. The unamortized balance of excess cost over the underlying equity in the net assets of Dixie was $35.7 million at December 31, 2001.

- Starfish Pipeline Company LLC ("Starfish") -- a 50% interest in a natural gas gathering system and related dehydration and other facilities located in south Louisiana and the Gulf of Mexico offshore Louisiana.

- Neptune Pipeline Company LLC ("Neptune") -- a 25.67% interest in the natural gas gathering and transmission systems owned by Manta Ray Offshore Gathering Company, LLC and Nautilus Pipeline Company LLC located in the Gulf of Mexico offshore Louisiana.

- Nemo Gathering Company, LLC ("Nemo") -- a 33.92% interest in a natural gas gathering system located in the Gulf of Mexico offshore Louisiana that became operational in August 2001.

- Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp. (collectively, "Evangeline") -- an approximate 49.5% aggregate interest in a natural gas pipeline system located in south Louisiana. We acquired our interest in Evangeline as a result of the Acadian Gas acquisition (see Note 2 for a description of this acquisition).

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

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

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

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

In addition to Starfish, we acquired a 25.67% interest in Ocean Breeze Pipeline Company ("Ocean Breeze") and Neptune and a 33.92% interest in Nemo. Ocean Breeze and Neptune collectively owned the Manta Ray and Nautilus natural gas pipeline systems located in the Gulf of Mexico offshore Louisiana. The Manta Ray system comprises approximately 235 miles of unregulated pipelines and related equipment with an optimal design capacity of 0.75 Bcf/d and the Nautilus system comprises approximately 101 miles of FERC-regulated pipelines with an optimal design capacity of 0.6 Bcf/d. The Nemo system, which became operational in August 2001, comprises 24-mile natural gas pipeline with an optimal design capacity of 0.3 Bcf/d. Like Stingray, Shell is the operator of the Manta Ray and Nemo systems. Shell is the administrative agent for Nautilus. In November 2001, Ocean Breeze was merged into Neptune with the Company retaining its 25.67% interest in Neptune. Shell and Marathon are the co-owners of Neptune and Shell owns the remaining interest in Nemo.

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

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

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

OCTANE ENHANCEMENT SEGMENT:

At December 31, 2001, the Octane Enhancement segment included our 33.33% interest in Belvieu Environmental Fuels ("BEF"), a facility located in southeast Texas that produces motor gasoline additives to enhance octane. The BEF facility currently produces MTBE. The production of MTBE is driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990 and other legislation and as an additive to increase octane in motor gasoline. Any changes to these oxygenated fuel programs that enable localities to elect to not participate in these programs, lessen the requirements for oxygenates or favor the use of non-isobutane based oxygenated fuels reduce the demand for MTBE and could have an adverse effect on our results of operations.

In recent years, MTBE has been detected in water supplies. The major source of the ground water contamination appears to be leaks from underground storage tanks. Although these detections have been limited and the great majority have been well below levels of public health concern, there have been calls for the phase-out of MTBE in motor gasoline in various federal and state governmental agencies and advisory bodies.

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

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

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

PROCESSING SEGMENT:

At December 31, 2001, our investments in and advances to unconsolidated affiliates also includes Venice Energy Services Company, LLC ("VESCO"). The VESCO investment consists of a 13.1% interest in a company owning a natural gas processing plant, fractionation facilities, storage, and gas gathering pipelines in Louisiana. We account for this investment using the cost method.

5. RECENTLY ISSUED ACCOUNTING STANDARDS

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

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

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

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

6. LONG-TERM DEBT

Our long-term debt consisted of the following at:

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

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

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

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

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

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

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

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

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

The MBFC Loan is subject to a make-whole redemption right and is guaranteed by the MLP through an unsecured and unsubordinated guarantee. The indenture agreement contains an acceleration clause whereby the outstanding principal and interest on the loan may become due and payable if our credit ratings decline below a Baa3 rating by Moody's (currently Baa2) and below a BBB- rating by Standard and Poors (currently BBB). Under these circumstances, the trustee (as defined in the indenture agreement) may, and if requested to do so by holders of at least 25% in aggregate of the principal amount of the outstanding underlying bonds, shall accelerate the maturity of the MBFC Loan, whereby the principal and all accrued interest would become immediately due and payable. If such an event occurred, we would have the option (a) to redeem the MBFC loan or (b) to provide an alternate credit agreement (as defined in the indenture agreement) to support our obligation under the MBFC loan, with both options exercisable within 120 days of receiving notice of the decline in our credit ratings from the ratings agencies.

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

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

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

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

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

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

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

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

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

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

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

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

February 2001 Registration Statement

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

Increase in fair value of fixed-rate debt

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

Impact of interest rate swap agreements upon interest expense

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

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

7. CAPITAL STRUCTURE

The Second Amended and Restated Agreement of Limited Partnership of the Company (the "Partnership Agreement") sets forth the calculation to be used to determine the amount and priority of cash distributions that the Common and Subordinated Unitholders and the General Partner will receive. The Partnership Agreement also contains provisions for the allocation of net earnings and losses to the Unitholders and the General Partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. Normal allocations according to percentage interests are done only, however, after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated 100% to the General Partner. As an incentive, the General Partner's percentage interest in quarterly distributions is increased after certain specified target levels are met. When quarterly distributions exceed $0.253 per Unit, the General Partner receives a percentage of the excess between the actual distribution rate and the target level ranging from approximately 15% to 50% depending on the target level achieved.

The Partnership Agreement generally authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as shall be established by the General Partner in its sole discretion without the approval of Unitholders. During the Subordination Period (as described under "Subordinated Units" below), however, we are limited with regards to the number of equity securities that we may issue that rank senior to Common Units (except for Common Units upon conversion of Subordinated Units, pursuant to employee benefit plans, upon conversion of the general partner interest as a result of the withdrawal of the General Partner or in connection with acquisitions or capital improvements that are accretive on a per Unit basis) or an equivalent number of securities ranking on a parity with the Common Units, without the approval of the holders of at least a Unit Majority. A Unit Majority is defined as at least a majority of the outstanding Common Units (during the Subordination Period), excluding Common Units held by the General Partner and its affiliates, and at least a majority of the outstanding Common Units (after the Subordination Period). After adjusting for the Units issued in connection with the TNGL acquisition, the number of Common Units available (and unreserved) to us for general partnership purposes during the Subordination Period was 54,550,000 at December 31, 2001.

SUBORDINATED UNITS. The 42,819,740 Subordinated Units have no voting rights until converted into Common Units at the end of the Subordination Period. The Subordination Period will generally extend until the first day of any quarter beginning after June 30, 2003 when the Conversion Tests have been satisfied. Generally, the Conversion Test will have been satisfied when we have paid from Operating Surplus and generated from Adjusted Operating Surplus the minimum quarterly distribution on all Units for each of the three preceding four-quarter periods. Upon expiration of the Subordination Period, all remaining Subordinated Units will convert into Common Units on a one-for-one basis and will thereafter participate pro rata with the other Common Units in distributions of Available Cash.

The Partnership Agreement stipulates that 50% of the Subordinated Units may undergo an early conversion into Common Units should certain criteria be satisfied. Based upon these criteria, the earliest that the first 25% of the Subordinated Units would convert into Common Units is May 1, 2002. Should the criteria continue to be satisfied through the first quarter of 2003, an additional 25% of the Subordinated Units would undergo an early conversion into Common Units on May 1, 2003. The remaining 50% of Subordinated Units would convert on August 1, 2003 should the balance of the conversion requirements be met.

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

We issued 29.0 million Special Units to Shell in August 1999 in connection with TNGL acquisition. Subsequently, Shell met certain performance criteria in 2000 and 2001 that obligated us to issue an additional 12.0 million Special Units to Shell -- 6.0 million were issued in August 2000 and 6.0 million in August 2001 under a contingent unit agreement. Of the cumulative 41.0 million Special Units issued, 12.0 million have already converted to Common Units (2.0 million in August 2000 and 10.0 million in August 2001). The remaining Special Units will convert to Common Units on a one for one basis as follows: 19.0 million in August 2002 and 10.0 million in August 2003. These conversions have a dilutive effect on basic earnings per Unit.

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

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

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

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

TREASURY UNITS ACQUIRED BY TRUST. During the first quarter of 1999, the Operating Partnership established the Trust to fund potential future obligations under the EPCO Agreement with respect to EPCO's long-term incentive plan (through the exercise of options granted to EPCO employees or directors of the General Partner). The Common Units purchased by the Trust are accounted for in a manner similar to treasury stock under the cost method of accounting. The Trust purchased 534,400 Common Units in 1999 at a cost of $4.7 million and 792,800 Common Units in 2001 at a cost of $18.0 million.

In November 2001, the Trust sold 1,000,000 Common Units previously held in treasury to EPCO for $22.6 million. The sales price of the treasury Common Units sold exceeded the purchase price of the Treasury Units by $6.0 million and has been credited to Partners' Equity accounts in a manner similar to additional paid-in capital.

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

	LIMITED PARTNERS			
	COMMON UNITS	SUBORDINATED UNITS	SPECIAL UNITS	TREASURY UNITS
Balance, December 31, 1997	67,105,830	42,819,740		
Units issued to public	24,000,000			
Balance, December 31, 1998	91,105,830	42,819,740		
Special Units issued to Shell in connection with TNGL acquisition			29,000,000	
Treasury Units purchased by consolidated Trust	(534,400)			534,400
Balance, December 31, 1999	90,571,430	42,819,740	29,000,000	534,400
Additional Special Units issued to Coral Energy, LLC in connection with contingency agreement			6,000,000	
Conversion of 2.0 million Coral Energy, LLC Special Units into Common Units	2,000,000		(2,000,000)	
Units repurchased and retired in connection with buy-back program	(56,800)			

---------- Balance,
December 31,
2000..............
92,514,630 42,819,740
33,000,000 534,400

	LIMITED PARTNERS			
	COMMON UNITS	SUBORDINATED UNITS	SPECIAL UNITS	TREASURY UNITS
Additional Special Units issued to Coral Energy, LLC in connection with contingency agreement.........			6,000,000	
Conversion of 10.0 million Coral Energy, LLC Special Units into Common Units.......................	10,000,000		(10,000,000)	
Treasury Units purchased by consolidated Trust.................	(792,800)			792,800
Treasury Units reissued by consolidated Trust.................	1,000,000			(1,000,000)
Balance, December 31, 2001.............	102,721,830	42,819,740	29,000,000	327,200

8. EARNINGS PER UNIT

Basic earnings per Unit is computed by dividing net income available to limited partner interests by the weighted-average number of Common and Subordinated Units outstanding during the period. Diluted earnings per Unit is computed by dividing net income available to limited partner interests by the weighted-average number of Common, Subordinated and Special Units outstanding during the period. The following table reconciles the number of Units used in the calculation of basic earnings per Unit and diluted earnings per Unit for each of the three years ended December 31, 2001, 2000 and 1999.

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

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

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

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

9. DISTRIBUTIONS

We intend, to the extent there is sufficient available cash from Operating Surplus, as defined by the Partnership Agreement, to distribute to each holder of Common Units at least a minimum quarterly distribution of $0.225 per Common Unit. The minimum quarterly distribution is not guaranteed and is subject to adjustment as set forth in the Partnership Agreement. With respect to each quarter during the Subordination Period, the Common Unitholders will generally have the right to receive the minimum quarterly distribution, plus any arrearages thereon, and the General Partner will have the right to receive the related distribution on its interest before any distributions of available cash from Operating Surplus are made to the Subordinated Unitholders. As an incentive, the General Partner's interest in quarterly distributions is increased after certain specified target levels are met. We made incentive distributions to the General Partner of $3.2 million during 2001 and $0.4 million during 2000.

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

	CASH DISTRIBUTION HISTORY			
	PER COMMON UNIT	PER SUBORDINATED UNIT	RECORD DATE	PAYMENT DATE
1999				
1st Quarter	$0.2250	$0.0350	Apr. 30, 1999	May 12, 1999
2nd Quarter	$0.2250	$0.1850	Jul. 30, 1999	Aug. 11, 1999
3rd Quarter	$0.2250	$0.2250	Oct. 29, 1999	Nov. 10, 1999
4th Quarter	$0.2500	$0.2500	Jan. 31, 2000	Feb. 10, 2000
2000				
1st Quarter	$0.2500	$0.2500	Apr. 28, 2000	May 10, 2000
2nd Quarter	$0.2625	$0.2625	Jul. 31, 2000	Aug. 10, 2000
3rd Quarter	$0.2625	$0.2625	Oct. 31, 2000	Nov. 10, 2000
4th Quarter	$0.2750	$0.2750	Jan. 31, 2001	Feb. 9, 2001
2001				
1st Quarter	$0.2750	$0.2750	Apr. 30, 2001	May 10, 2001
2nd Quarter	$0.2938	$0.2938	Jul. 31, 2001	Aug. 10, 2001
3rd Quarter	$0.3125	$0.3125	Oct. 31, 2001	Nov. 9, 2001
4th Quarter	$0.3125	$0.3125	Jan. 31, 2002	Feb. 11, 2002

The quarterly cash distribution amounts shown in the table correspond to the cash flows for the quarters indicated. The actual cash distributions (i.e., payments to our limited partners) occur within 45 days after the end of such quarter.

10. RELATED PARTY TRANSACTIONS

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

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

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

- allow us to participate as named insureds in EPCO's current insurance program with the costs being allocated among the parties on the basis of formulas set forth in the agreement;

- grant us an irrevocable, non-exclusive worldwide license to use all of the EPCO trademarks and trade names;

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

- sublease to us all of the equipment which it holds pursuant to operating leases relating to an isomerization unit, a deisobutanizer tower, two cogeneration units and approximately 100 railcars for one dollar per year and to assign its' purchase option under such leases to us. EPCO remains liable for the lease payments associated with these assets.

Operating costs and expenses (as shown in the audited Statements of Consolidated Operations) treat the full amount of lease payments being made by EPCO as a non-cash operating expense (with the offset to Partners' Equity on the Consolidated Balance Sheet). In addition, operating costs and expenses include compensation charges for EPCO's employees who operate the facilities.Pursuant to the EPCO Agreement, we reimburse EPCO for our portion of the costs of certain of its employees who manage our business and affairs. In general, our reimbursement of EPCO's expense associated with administrative positions that were active at the time of our initial public offering in July 1998 is capped by the Administrative Services Fee that we pay (currently at $16 million annually). The General Partner, with the approval and consent of the Audit and Conflicts Committee, may agree to annual increases of such fee up to ten percent per year during the 10-year term of the EPCO Agreement. Any difference between the actual costs of this "pre-expansion" group (including those associated with equity-based awards granted to certain individuals within this group) and the Administrative Services Fee will be retained by EPCO (i.e., EPCO solely bears any shortfall in reimbursement for this group).

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

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

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

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

Other related party and similar transactions with EPCO or its affiliates

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

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

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

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

Relationships with Shell

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

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

- the exclusive right to process any and all of Shell's Gulf of Mexico natural gas production from existing and future dedicated leases; plus

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

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

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

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

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

11. COMMITMENTS AND CONTINGENCIES

REDELIVERY COMMITMENTS

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

LEASE COMMITMENTS

We lease certain equipment and processing facilities under noncancelable and cancelable operating leases. Minimum future rental payments on such leases with terms in excess of one year at December 31, 2001 are as follows:

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

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

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

PURCHASE COMMITMENTS

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

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

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

LITIGATION

We are indemnified for any litigation pending as of the date of our formation by EPCO. We are sometimes named as a defendant in litigation relating to our normal business operations. Although we insure against various business risks, to the extent management believes it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings asa result of ordinary business activity. Except as noted below, management is not aware of any significant litigation, pending or threatened, that would have a significant adverse effect on our financial position or results of operations.

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

Regulations imposing more strict air emissions requirements on existing facilities in the Houston-Galveston area were issued in December 2000. These regulations may necessitate extensive redesign and modification of our Mont Belvieu facilities to achieve the air emissions reductions needed for federal Clean Air Act compliance. The technical practicality and economic reasonableness of these regulations have been challenged under state law in litigation filed on January 19, 2001, against the Texas Natural Resource Conservation Commission and its principal officials in the District Court of Travis County, Texas, by a coalition of major Houston-Galveston area industries, including us. Until this litigation is resolved, the precise level of technology to be employed and the cost for modifying the facilities to achieve the required amount of reductions cannot be determined. Currently, the litigation has been stayed by agreement of the parties pending the outcome of expanded, cooperative scientific research to more precisely define sources and mechanisms of air pollution in the Houston-Galveston area. Completion of this research is anticipated in mid-2002.

12. SUPPLEMENTAL CASH FLOWS DISCLOSURE

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

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

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

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

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

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

13. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices in our natural gas and NGL businesses and in interest rates with respect to a portion of our debt obligations. We may use financial instruments (i.e., futures, forwards, swaps, options, and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions, primarily in its Processing segment. In general, the types of risks hedged are those relating to the variability of future earnings and cash flows caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

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

COMMODITY FINANCIAL INSTRUMENTS

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

We have adopted a commercial policy to manage our exposure to the risks of its natural gas and NGL businesses. The objective of this policy is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by the General Partner. We enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to its commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 18 months. The General Partner oversees the our strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

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

At December 31, 2001, we had open commodity financial instruments that settle at different dates extending through December 2002. We routinely review our outstanding instruments in light of current market conditions. If market conditions warrant, some instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific exposure. When this occurs, we may enter into a new commodity financial instrument to reestablish the economic hedge to which the closed instrument relates.

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

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

INTEREST RATE SWAPS

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

We assess interest rate cash flow risk by identifying and measuring changes in interest rate exposure that impact future cash flows and evaluating hedging opportunities. We use analytical techniques to measure its exposure to fluctuations in interest rates, including cash flow sensitivity analysis to estimate the expected impact of changes in interest rates on our future cash flows.

The General Partner oversees the strategies associated with financial risks and approves instruments that are appropriate for our requirements. The notional amount of an interest rate swap does not represent exposure to credit loss. We monitor our positions and the credit ratings of counterparties. Management believes the risk of incurring a credit loss is remote, and that if incurred, such losses would be immaterial.

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

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

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

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

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

FUTURE ISSUES CONCERNING SFAS NO. 133

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

OTHER FAIR VALUE INFORMATION

Cash and cash equivalents, Accounts Receivable, Accounts Payable and Accrued Expenses are carried at amounts which reasonably approximate their fair value at year end due to their short-term nature.

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

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

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

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

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

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

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

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

14. SIGNIFICANT CONCENTRATIONS OF RISK

CREDIT RISK. A substantial portion of our revenues are derived from various companies in the NGL and petrochemical industry, located in the United States. Although this concentration could affect our overall exposure to credit risk since these customers might be affected by similar economic or other conditions, management believes we are exposed to minimal credit risk, since the majority of our business is conducted with major companies within the industry including those with whom it has joint operations. We do not require collateral for our accounts receivable.

NATURE OF OPERATIONS. We are subject to a number of risks inherent in the industry in which it operates, including fluctuating gas and liquids prices. Our financial condition and results of operation will depend significantly on the prices received for NGLs and the price paid for gas consumed in the NGL extraction process. These prices are subject to fluctuations in response to changes in supply, market uncertainty, weather and a variety of additional factors that are beyond our control.

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

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

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

In December 2001, Enron Corp., or Enron, filed for protection under Chapter 11 of the U.S. Bankruptcy Code. As a result, we established a $10.6 million reserve for amounts owed to us by Enron North America, a subsidiary of Enron. Enron North America was our counterparty to various past financial instruments. The Enron amounts were unsecured and the amount that we may ultimately recover, if any, is not presently determinable. Of the reserve amount established, $4.3 million was attributable to various unbilled commodity financial instrument positions that terminate during the first quarter of 2002.

15. SEGMENT INFORMATION

Operating segments are components of a business about which separate financial information is available and that are regularly evaluated by the chief operating decision maker in deciding how to allocate resources and in assessing performance. Generally, financial information is required to be reported on the basis that it is used internally for evaluating segment performance and deciding how to allocate resources to segments.

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

We evaluate segment performance based on gross operating margin. Gross operating margin reported for each segment represents operating income before depreciation and amortization, lease expense obligations retained by EPCO, gains and losses on the sale of assets and general and administrative expenses. In addition, segment gross operating margin is exclusive of interest expense, interest income (from unconsolidated affiliates or others), dividend income from unconsolidated affiliates, minority interest, extraordinary charges and other income and expense transactions.

We include equity earnings from unconsolidated affiliates in segment gross operating margin and as a component of revenues. Our equity investments with industry partners are a vital component of our business strategy and a means by which we conduct our operations to align our interests with a supplier of raw materials to a facility or a consumer of finished products from a facility. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand alone basis. Many of these businesses perform supporting or complementary roles to our other business operations. For example, we use the Promix NGL fractionator to process NGLs extracted by our gas plants. The NGLs received from Promix then can be sold by our merchant businesses. Another example would be our relationship with the BEF MTBE facility. Our isomerization facilities process normal butane for this plant and our HSC pipeline transports MTBE for delivery to BEF's storage facility on the Houston Ship Channel.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are allocated to each segment on the basis of each asset's or investment's principal operations. The principal reconciling item between consolidated property, plant and equipment and segment property is construction-in-progress. Segment property represents those facilities and projects that contribute to gross operating margin and is net of accumulated depreciation on these assets. Since assets under construction do not generally contribute to segment gross operating margin, these assets are not included in the operating segment totals until they are deemed operational.

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

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

OPERATING SEGMENTS ----

OCTANE ADJS. AND
CONSOL. FRACTIONATION
PIPELINES PROCESSING
ENHANCEMENT OTHER
ELIMS. TOTALS ---------
---- --------- -------
----------- ----------
------ --------- ------
---- Revenues from
external customers:
2001....................
$324,276 $403,430
$2,424,281 $2,382
$3,154,369
2000....................
396,995 28,172
2,620,975 2,878
3,049,020
1999....................
247,579 11,498
1,073,171 731 1,332,979
Intersegment revenues:
2001....................
158,853 89,907 683,524
389 $(932,673)
2000....................
177,963 55,690 630,155
375 (864,183)
1999....................
118,103 43,688 216,720
444 (378,955) Equity
income in
unconsolidated
affiliates:
2001....................
6,945 12,742 $ 5,671
25,358
2000....................
6,391 7,321 10,407
24,119
1999....................
1,566 3,728 8,183
13,477 Total revenues:
2001....................
490,074 506,079
3,107,805 5,671 2,771
(932,673) 3,179,727
2000....................
581,349 91,183
3,251,130 10,407 3,253
(864,183) 3,073,139
1999....................
367,248 58,914
1,289,891 8,183 1,175
(378,955) 1,346,456
Gross operating margin
by segment:
2001....................
118,610 96,569 154,989
5,671 944 376,783
2000....................
129,376 56,099 122,240
10,407 2,493 320,615
1999....................
110,424 31,195 28,485
8,183 908 179,195
Segment assets:
2001....................

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

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

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

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

16. SUBSEQUENT EVENTS (UNAUDITED)

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

The storage facilities include 30 salt dome storage caverns with a total useable capacity of 68 million barrels, local distribution pipelines and related equipment. The facilities provide storage services for mixed natural gas liquids, ethane, propane, butanes, natural gasoline and olefins (such as ethylene), polymer grade propylene, chemical grade propylene and refinery grade propylene. The facilities are located in Mont Belvieu, Texas.

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

The propylene fractionation assets being acquired include a 66.67% interest in a polymer grade propylene fractionation facility located in Mont Belvieu, Texas, a 50.0% interest in an entity which owns a polymer grade propylene export terminal located on the Houston Ship Channel in La Porte, Texas and varying interests in several supporting distribution pipelines and related equipment. The propylene fractionation facility has the gross capacity to produce approximately 41,000 barrels per day of polymer grade propylene.

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

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

17. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
FOR THE YEAR ENDED DECEMBER 31, 2000:				
Revenues	$753,724	$604,010	$721,863	$993,542
Operating income	75,434	50,046	55,864	62,390
Income before minority interest	70,156	46,026	50,777	55,800
Minority interest	(709)	(466)	(514)	(564)
Net income	69,447	45,560	50,263	55,236
Net income per Unit, basic	$ 0.52	$ 0.34	$ 0.37	$ 0.41
Net income per Unit, diluted	$ 0.43	$ 0.28	$ 0.30	$ 0.33
FOR THE YEAR ENDED DECEMBER 31, 2001:				
Revenues	$838,326	$968,447	$729,618	$643,336
Operating income	54,417	109,071	87,406	36,794
Income before minority interest	52,804	93,975	75,774	22,097
Minority interest	(534)	(944)	(767)	(227)
Net income	52,270	93,031	75,007	21,870
Net income per Unit, basic	$ 0.38	$ 0.68	$ 0.52	$ 0.14
Net income per Unit, diluted	$ 0.31	$ 0.55	$ 0.43	$ 0.12

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