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

FORM 10-K/A
AMENDMENT NO. 1

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2001

OR

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

For the transition period from __________ to__________

COMMISSION FILE NO. 1-11680

EL PASO ENERGY PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

DELAWARE (State or Other Jurisdiction of Incorporation or Organization)	76-0396023 (I.R.S. Employer Identification No.)
4 GREENWAY PLAZA HOUSTON, TEXAS (Address of Principal Executive Offices)	77046 (Zip Code)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE: (832) 676-2600

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

TITLE OF EACH CLASS NAME OF EACH EXCHANGE ON WHICH REGISTERED
Common units representing limited partner interests New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: NONE.

INDICATE BY CHECK MARK WHETHER THE REGISTRANT (1) HAS FILED ALL REPORTS REQUIRED TO BE FILED BY SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 DURING THE PRECEDING 12 MONTHS (OR FOR SUCH SHORTER PERIOD THAT THE REGISTRANT WAS REQUIRED TO FILE SUCH REPORTS), AND (2) HAS BEEN SUBJECT TO SUCH

FILING REQUIREMENTS FOR THE PAST 90 DAYS. YES [X] NO [ ]

INDICATE BY CHECK MARK IF DISCLOSURE OF DELINQUENT FILERS PURSUANT TO ITEM 405 OF REGULATION S-K IS NOT CONTAINED HEREIN, AND WILL NOT BE CONTAINED, TO THE BEST OF REGISTRANT'S KNOWLEDGE, IN DEFINITIVE PROXY OR INFORMATION STATEMENTS INCORPORATED BY REFERENCE IN PART III OF THIS FORM 10-K OR ANY AMENDMENT TO THIS FORM 10-K. [ ]

THE REGISTRANT HAD 39,738,974 COMMON UNITS OUTSTANDING AS OF FEBRUARY 27, 2002. THE AGGREGATE MARKET VALUE ON SUCH DATE OF THE REGISTRANT'S COMMON UNITS HELD BY NON-AFFILIATES WAS APPROXIMATELY $1,393 MILLION.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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The purpose of this Amendment No. 1 to El Paso Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2001 (the "Original 10-K") is to amend the disclosure under the captions "Oil and Natural Gas Production-Net Production, Unit Prices and Production Costs" in Item 1, Business, and "Note 16-Supplemental Oil and Natural Gas Information (Unaudited)" in Item 8, Financial Statements and Supplemental Data, to present consistent information relating to our oil and natural gas producing activities effected by inter-segment platform access fees, which are eliminated in consolidation, and only to update the signature pages and to add certifications required by Sarbanes-Oxley Act of 2002 in Item 14, Exhibits, Financial Statement Schedules, and Reports on Form 8-K. This amendment contains no changes to our balance sheet, income statement, or statement of cash flows. This amendment primarily impacts our standardized measure of discounted future net cash flows and unit production disclosure. All other information included in the Original 10-K remains unchanged. This amendment does not reflect events occurring after the filing of the Original 10-K.

EL PASO ENERGY PARTNERS, L.P.

TABLE OF CONTENTS

CAPTION	PAGE
PART I	
Item 1. Business	1
PART II	
Item 8. Financial Statements and Supplementary Data	15
PART IV	
Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K	65
Signatures	82

PART I

ITEM 1. BUSINESS

GENERAL

Formed in 1993, we are one of the largest publicly traded master limited partnerships in terms of market capitalization. We currently manage a balanced, diversified portfolio of interests and assets that includes:

- oil and natural gas pipelines, platforms, processing facilities and other energy infrastructure assets in the deeper water regions of the Gulf of Mexico, primarily offshore Louisiana and Texas;

- intrastate natural gas pipeline assets in Alabama;

- Natural gas liquids (NGL) transportation and fractionation facilities in south Texas;

- natural gas processing facilities in New Mexico;

- natural gas and NGL storage facilities in Mississippi and Louisiana; and

- oil and natural gas properties in the Gulf of Mexico.

Our objective is to operate as a growth-oriented master limited partnership with a focus on increasing our cash flow, earnings and return to our unitholders. Our strategy is to combine our position as a provider of midstream services in the deeper water regions of the Gulf of Mexico with an aggressive effort to acquire and develop diversified onshore midstream energy infrastructure assets. Our strategy also includes identifying opportunities that create synergies with the other assets and operations of El Paso Corporation, the indirect parent of our general partner. We intend to continue de-emphasizing our commodity-based activities, such as exploration and production operations, and to concentrate on fee-based operations, such as gathering, transportation, processing, storage and fractionation, which traditionally provide more stable cash flows. We intend to execute our business strategy by:

- capitalizing on our extensive infrastructure in the Gulf of Mexico and expanding our existing assets further into the deeper water regions with projects supported by new discoveries and long-term commitments;

- purchasing or constructing onshore pipelines, gathering systems, storage, processing and fractionation facilities and other midstream assets to provide a broad range of more stable, fee-based services to producers, marketers and users of energy products; and

- leveraging the nationwide asset base and operational expertise of El Paso Corporation.

We regularly consider and enter into discussions regarding potential acquisitions, including those from El Paso Corporation or its subsidiaries, and expect to continue to do so in the future. In 2001, our cash outlay for investments of midstream energy infrastructure assets totaled $589 million. Assets acquired from El Paso Corporation and third parties totaled $344 million and $78 million, and funds expended for the construction of assets totaled $167 million.

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As generally used in the energy industry and in this document, the following terms have the following meanings:

/d	= per day
Bbl	= barrel
BBtu	= billion British thermal units
Bcf	= billion cubic feet
Dth	= dekatherm
MBbls	= thousand barrels
Mcf	= thousand cubic feet

MDth	= thousand dekatherms
MMBbls	= million barrels
MMBtu	= million British thermal units

MMcf	= million cubic feet
MMDth	= million dekatherms

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at 14.73 pounds per square inch.

In February 2002, we agreed to acquire midstream businesses from El Paso Corporation. The primary businesses to be acquired include:

- the 9,400 mile EPGT Texas intrastate pipeline, with a capacity of approximately 5 Bcf/d and average throughput of 3,500 MDth/d during 2001;

- 1,300 miles of gathering systems in the Permian Basin with a capacity of 465 MMcf/d and average net 2001 throughput of 341 MDth/d; and

- a 42.3 percent non-operating interest in the Indian Basin gas processing and treating plant and associated gathering lines.

Total consideration for these transactions is approximately $750 million and will include the following consideration to subsidiaries of El Paso Corporation:

- the sale of our Prince tension leg platform (TLP) and the 9 percent overriding royalty interest in the Prince Field for approximately $190 million after our repayment of the related limited recourse debt of $95 million;

- the issuance of $6 million in common units; and

- a cash payment of $554 million.

These amounts will be adjusted at closing for the value of working capital acquired or sold. We will retain third-party marketing rights for remaining platform capacity and an option to repurchase the TLP at the end of the Prince Field reserve life. We expect to finance the purchase of these businesses through debt and equity financing in accordance with our strategy to maintain a strong balance sheet. The transaction is expected to close in the first quarter of 2002 subject to receiving regulatory approvals and arranging satisfactory financing.

Also in February 2002, we announced that we will build and operate the Cameron Highway Oil Pipeline System, a 380-mile oil pipeline in the Gulf of Mexico. Cameron Highway will deliver up to 500 MBbl/d of oil from the southern Green Canyon and western Gulf of Mexico areas to Port Arthur and Texas City, Texas. The new pipeline is expected to be in service by the third quarter of 2004. We have entered into agreements with operating subsidiaries of BP p.l.c., BHP Billiton, and Unocal under which each of them have dedicated production from the Holstein, Mad Dog, and Atlantis Deepwater Trend discoveries for transportation on Cameron Highway. We will seek a partner or partners for up to 50 percent of the interest in the pipeline.

In January 2002, we acquired a 3.3 million barrel propane storage business and complete leaching operation located in Hattiesburg, Mississippi from Suburban Propane Partners, L.P. As part of the transaction, we entered into a long-term propane storage agreement with Suburban Propane Partners for a portion of the acquired propane storage capacity. We intend to convert a portion of these assets to natural gas storage and will integrate them with our adjacent Petal natural gas storage facility. In December 2001, we acquired Anse La Butte, a 3.2 million barrel NGL multi-product storage facility near Breaux Bridge, Louisiana. We entered into long-term storage agreements with a third party and a subsidiary of El Paso Corporation for a significant portion of the storage capacity.

Also in December 2001, we announced an agreement with Anadarko Petroleum Corporation to jointly develop Anadarko's Marco Polo discovery, using a floating production platform capable of accommodating production from multiple fields. In conjunction with this agreement, we formed a 50/50 joint venture to construct, install, and own the platform with Cal Dive International, Inc. The platform's production capacity is expected to be 100 MBbls/d of oil and 250 Mcf/d of gas. Anadarko will have firm capacity of 50 MBbls/d of oil and 150 Mcf/d of gas. The remainder of the platform capacity will be available to Anadarko for additional production and/or to third parties that have fields developed in the area. Anadarko will operate the platform. We anticipate that the facilities will be completed in 2004.

In October 2001, we acquired interests in the titleholder of, and other interests in, the Chaco cryogenic natural gas processing plant, the third largest natural gas processing plant in the United States measured by liquids produced. The Chaco plant is a state-of-the-art cryogenic plant located in the San Juan Basin in New Mexico. It is capable of processing up to 700 Mdth/d of natural gas and handling up to 50 MBbls/d of NGLs.

In conjunction with this transaction, we also acquired the remaining 50 percent equity interest that we did not already own in Deepwater Holdings from a subsidiary of El Paso Corporation. As a result, the High Island Offshore System (HIOS) and the East Breaks natural gas gathering system (East Breaks) became indirect wholly-owned assets.

Also in October 2001, we agreed to install a new natural gas pipeline from our Viosca Knoll system to the deepwater Medusa development in the Gulf of Mexico. We also entered into an agreement to provide natural gas gathering services for Murphy Exploration and Production Company's Medusa development. Construction of this pipeline is scheduled to begin in mid-2002, and first production from the Medusa development is anticipated by the fourth quarter of 2002. We also entered into an agreement to provide natural gas gathering services for TotalFinaElf's Matterhorn, Camden Hills and Aconcagua discoveries located in the Gulf of Mexico Deepwater Trend. Natural gas production from these fields will be delivered to our Viosca Knoll system. First production from Camden Hills and Aconcagua is anticipated in the summer of 2002. First production from Matterhorn is anticipated in the third quarter of 2003.

In February 2001, we acquired the south Texas fee-based NGL transportation and fractionation assets (EPN Texas) from a subsidiary of El Paso Corporation. These assets include more than 600 miles of NGL gathering and transportation pipelines, as well as three fractionation plants with a capacity of approximately 96 MBbls/d. These plants fractionate NGLs into ethane, propane and butane products, which are used by refineries and petrochemical plants along the Texas Gulf Coast.

In January 2001, we agreed to sell our interests in several offshore Gulf of Mexico assets, including our interests in the Nautilus, Manta Ray Offshore, Nemo, Green Canyon and Tarpon natural gas pipeline systems, as well as interests in two offshore platforms. In addition, we and Deepwater Holdings agreed to sell our joint interests in the Stingray System, UT Offshore System (UTOS), and the West Cameron dehydration facility. These sales occurred as a result of a Federal Trade Commission (FTC) order relating to El Paso Corporation's merger with The Coastal Corporation.

SEGMENTS

We segregate our business activities into five segments:

- Natural Gas Gathering and Transportation;

- Liquid Transportation and Handling;

- Platforms;

- Natural Gas Storage; and

- Oil and Natural Gas Production.

These segments are strategic business units that provide a variety of energy related services. For information relating to operating revenues and operating income of each segment, see Item 8, Financial Statements and Supplementary Data, Note 13. Each of these segments is discussed more fully below.

NATURAL GAS GATHERING AND TRANSPORTATION

Our pipeline systems extend over 870 miles and have a combined maximum design capacity of over 3.4 Bcf/d of natural gas. Our offshore natural gas pipeline systems are strategically located to serve production activities in some of the most active drilling and development regions in the Gulf of Mexico, including select locations offshore of Texas, Louisiana and Mississippi, and to provide relatively low cost access to long-line transmission pipelines that access multiple markets in the eastern half of the United States. In addition to our offshore natural gas pipeline systems, we have a gathering system that serves the coal bed methane producing regions of Alabama and a small pipeline lateral in New Mexico. The following table and discussions describe our natural gas pipelines, all of which we wholly-own and operate.

	VIOSCA KNOLL	HIOS(1)	EAST BREAKS(1)	EL PASO INTRASTATE-ALABAMA	INDIAN BASIN
Unregulated(U)/regulated(R)	U	R	U	U	U
In-service date	1994	1977	2000	1972	2001
Approximate capacity(2)	1,000	1,800	400	200	65
Aggregate miles of pipeline	125	204	85	450	10
Average throughput for the years ended:(3)					
December 31, 2001	551	979	245	171	22
December 31, 2000	612	870	112	120	--
December 31, 1999	709	792	--	--	--

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(1) The average throughput reflects 100 percent of the throughput. Prior to October 2001, we owned a 50 percent interest in HIOS and East Breaks through Deepwater Holdings. We acquired the remaining 50 percent interest in October 2001 from subsidiaries of El Paso Corporation.
(2) All capacity measures are on a MMcf/d basis.
(3) All average throughput measures are on a MDth/d basis. For the pipelines described above, one MDth is substantially equivalent to one MMcf.

Viosca Knoll System. The Viosca Knoll system is an offshore natural gas gathering system designed to serve the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico and consists of 125 miles of predominantly 20-inch natural gas pipeline and a 7,000 horsepower compressor. During 1999, we acquired an additional 49 percent interest in the Viosca Knoll system, and in 2000 we acquired the remaining one percent from a subsidiary of El Paso Corporation, bringing our total interest in the Viosca Knoll system to 100 percent. The system provides its customers access to the facilities of a number of major interstate pipelines, including pipelines owned by Tennessee Gas Pipeline Company, Columbia Gulf Transmission Company, Southern Natural Gas Company, Transcontinental Gas Pipeline Company (Transco) and Destin Pipeline Company.

HIOS. In October 2001, HIOS became a wholly-owned asset through our acquisition of the remaining 50 percent equity interest in Deepwater Holdings that we did not already own from subsidiaries of El Paso Corporation. HIOS is a natural gas transmission system regulated by the Federal Energy Regulatory Commission (FERC), that consists of 204 miles of pipeline. HIOS transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island, and East Breaks areas of the Gulf of Mexico to numerous downstream pipelines including the ANR and Tennessee Gas pipelines owned by El Paso Corporation.

East Breaks System. In October 2001, East Breaks became a wholly-owned asset through our acquisition of the remaining 50 percent equity interest in Deepwater Holdings that we did not already own from subsidiaries of El Paso Corporation. East Breaks is a natural gas gathering system that consists of an 85-mile pipeline that connects HIOS to the Hoover-Diana project developed by subsidiaries of ExxonMobil and BP in the Alaminos Canyon and East Breaks areas of the Gulf of Mexico. East Breaks was placed in service in June 2000 and has the ability to expand its throughput capacity further, which would provide HIOS with the ability to compete for the right to gather and transport the substantial reserves associated with properties being, and expected to be, developed in these deepwater frontier regions.

El Paso Intrastate-Alabama System. In March 2000, we acquired the EPIA system, a natural gas pipeline system that serves the coal bed methane producing regions of Alabama. The system consists of over 450 miles of pipeline. EPIA also provides marketing services through the purchase and resale of natural gas by purchasing natural gas from regional producers and others, and selling natural gas to local distribution companies and others.

Indian Basin. The Indian Basin lateral, located in southeast New Mexico, was placed into service in June 2001. This ten mile lateral connects the 300 MMcf/d Indian Basin processing and treating plant to El Paso Field Services' Carlsbad Gathering System. The lateral offers alternative market outlets to the Transwestern and El Paso Natural Gas pipeline systems.

Markets and Competition

Each of our natural gas pipeline systems are located at or near natural gas production areas that are served by other pipelines. Our natural gas pipeline systems face competition from both regulated and unregulated systems. Some of these competitors are not subject to the same level of rate and service regulation as we are. Other competing pipelines, such as long-haul transporters, may have rate design alternatives unavailable to ours. Consequently, those competing pipelines may be able to provide service on more flexible terms and at rates significantly below those we offer.

A majority of the revenues generated by our pipeline systems are attributed to production from reserves committed under long-term contracts for the productive life of the relevant field. Nonetheless, these reserves and other reserves that may become available to our pipeline systems are depleting assets and will be produced over a finite period. Each of our pipeline systems must access additional reserves to offset the natural decline in production from existing connected wells or the loss of any other production to a competitor. Furthermore, the rates we charge for our services are dependent on whether the relevant pipeline system is regulated or unregulated, the quality of the service required by the customer, and the amount and term of the reserve commitment by the customer. A majority of our offshore arrangements involve life-of-reserve commitments with both firm and interruptible components. Generally, we receive a price per dekatherm of natural gas handled.

Regulatory Environment

Our natural gas pipeline systems are subject to the Natural Gas Pipeline Safety Act of 1968, which establishes pipeline and liquified natural gas plant safety requirements. All of our offshore pipeline systems are subject to regulation under the Outer Continental Shelf Lands Act, which calls for nondiscriminatory transportation on pipelines operating in the outer continental shelf region of the Gulf of Mexico. All of our pipeline systems are subject to the National Environmental Policy Act and other environmental legislation. Each of the pipeline systems has a continuing program of inspection designed to keep all of our facilities in compliance with pollution control and pipeline safety requirements. We believe that our pipeline systems are in compliance with the applicable requirements of these regulations.

Our HIOS system is also subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. HIOS operates under a separate FERC approved tariff that governs its operations, terms and conditions of service and rates. The natural gas pipelines industry has historically been heavily regulated by federal and state government and we cannot predict what further actions FERC, state regulators, or federal and state legislators may take in the future.

In September 2001, FERC issued a Notice of Proposed Rulemaking (NOPR) that proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. Since HIOS is an interstate facility as defined by the Natural Gas Act, the proposed regulations, if adopted by FERC, would dictate how HIOS conducts business and interacts with all energy affiliates of El Paso Corporation and us. We cannot predict the outcome of the NOPR, but adoption of the regulations in substantially the form proposed would, at a minimum, place administrative and operational burdens on us. Further, more fundamental changes could be required such as a complete organizational separation or sale of HIOS.

Maintenance

Each of our pipeline systems requires regular maintenance. The interior of the pipelines is maintained through the regular cleaning of the line of liquids that collect in the pipeline. Corrosion inhibitors are also injected into all of the systems through the flow stream on a continuous basis. To prevent external corrosion of the pipe, anodes are fastened to the pipeline itself at prescribed intervals, providing protection from moisture or sea water. Our HIOS and Viosca Knoll systems include platforms that are manned on a continuous basis. The personnel onboard these platforms are responsible for site maintenance, operations of the platform facilities, measurement of the oil or natural gas stream at the source of production and corrosion control.

LIQUID TRANSPORTATION AND HANDLING

NGL Transportation and Fractionation Facilities

In February 2001, we acquired EPN Texas from a subsidiary of El Paso Corporation. EPN Texas includes more than 600 miles of intrastate NGL gathering and transportation pipelines and three fractionation plants located in south Texas. The intrastate NGL pipeline system is comprised of 379 miles of pipeline used to gather and transport unfractionated NGLs from various processing plants to the Shoup Plant, located in Corpus Christi, the largest of EPN Texas' three fractionators. The system also includes 177 miles of pipelines that deliver fractionated products such as ethane, propane and butane to refineries and petrochemical plants along the Texas Gulf Coast and to common carrier NGL pipelines. The three fractionation facilities have a combined capacity of approximately 96 MBbls/d.

Utilization rates in the fractionation industry can fluctuate dramatically from month to month, depending on the needs of producers. The average annual utilization rate of the fractionation facilities for 2001, 2000, and 1999 was 73 percent, 89 percent, and 88 percent. We secured a commitment from a subsidiary of El Paso Corporation that the utilization rate of these facilities during 2001 would be at least 85 percent. This commitment expired on December 31, 2001.

Natural Gas Processing Facility

In October 2001, we acquired interests in the titleholder of, and other interests in, the Chaco cryogenic natural gas processing plant, the third largest natural gas processing plant in the United States measured by liquids produced. The Chaco plant is a state-of-the-art cryogenic plant located in the San Juan Basin in New Mexico that uses high pressures and extremely low temperatures to remove water, impurities and excess hydrocarbon liquids from the raw natural gas stream and to recover ethane, propane and the heavier hydrocarbons. It is capable of processing up to 700 MDth/d of natural gas and handling up to 50 MBbls/d of NGLs. The average utilization rate for the Chaco plant for the calendar years 2001, 2000, and 1999 was 89 percent, 91 percent, and 93 percent. The average utilization rate from our acquisition date of October 18, 2001 to December 31, 2001, was 93 percent.

Offshore Oil Pipeline Systems

We have interests in two offshore oil pipeline systems, which extend over 300 miles and have a combined capacity of 480 MBbls/d of oil with the addition of pumps and the use of friction reducers. In addition to being strategically located in the vicinity of some prolific producing regions in the Gulf of Mexico, our oil pipeline systems are parallel to and interconnect with key segments of some of our natural gas pipeline systems and offshore platforms, which contain separation and handling facilities. This distinguishes us from our competitors by allowing us to provide some producing properties with a unique single point of contact through which they may access a wide range of midstream services and assets.

Poseidon System. Poseidon is a major offshore sour crude oil pipeline system built in response to the increased demand for additional sour crude oil pipeline capacity in the central Gulf of Mexico. We own an effective 36 percent interest in Poseidon and began operating this system in January 2001. Poseidon has a maximum design capacity of 400 MBbls/d with the addition of pumps and the use of friction reducers. Our average net throughput was 56 MBbls/d, 57 MBbls/d, and 61 MBbls/d for the years ended December 31, 2001, 2000 and 1999. The Poseidon system consists of:

- 117 miles of 16-inch to 20-inch diameter pipeline extending from our 50 percent owned Garden Banks 72 platform to our 50 percent owned Ship Shoal 332 platform;

- 122 miles of 24-inch diameter pipeline extending from the Ship Shoal 332 platform to Houma, Louisiana;

- 32 miles of 16-inch diameter pipeline extending from Ewing Bank Block 873 to the 24-inch pipeline in the area of South Timbalier Block 212; and

- 17 miles of 16-inch pipeline extending from Garden Banks Block 260 to South Marsh Island Block 205.

Allegheny System. Our Allegheny system is an offshore crude oil system consisting of 43 miles of 14-inch diameter pipeline that connects the Allegheny field in the Green Canyon area of the Gulf of Mexico with Poseidon at our 50 percent owned Ship Shoal 332 platform. Allegheny has an approximate capacity of 80 MBbls/d and our average throughput was 13 MBbls/d, 18 MBbls/d, and 12 MBbls/d for the years ended December 31, 2001, 2000 and 1999. Oil production from the Allegheny field is committed to this system. The Allegheny system was placed into service in October 1999.

Markets and Competition

Utilization of our processing and fractionation facilities occurs only when the producer can receive more net proceeds by physically separating and selling the NGL components contained in the raw natural gas stream than they would receive by merely selling the raw natural gas stream. The spread between the prices for natural gas and NGLs is greatest when the demand for NGLs increases, which often occurs in the winter. If, and when, this spread becomes too narrow to justify the costs, producers will choose to sell the raw natural gas stream rather than process and fractionate, and our fractionation facilities will be underutilized.

In connection with our acquisition of EPN Texas, we entered into a 20-year fee-based transportation and fractionation agreement and have dedicated 100 percent of the capacity of our fractionation facilities to a subsidiary of El Paso Corporation. In this agreement, all of the NGLs derived from processing operations at seven natural gas processing plants in south Texas owned by subsidiaries of El Paso Corporation are delivered to our NGL transportation and fractionation facilities. Effectively, we will receive a fixed fee for each barrel of NGLs transported and fractionated by our facilities. Approximately 25 percent of our per barrel fee is escalated annually for increases in inflation. El Paso Corporation's subsidiary will bear substantially all of the risks and rewards associated with changes in the commodity prices for NGLs.

In connection with the Chaco transaction, we entered into a 20-year fee-based processing agreement with El Paso Field Services. In accordance with the original construction financing agreements, the Chaco plant is under an operating lease to El Paso Field Services. They have the right to purchase the Chaco Plant at the end of the lease term in October 2002 for approximately $77 million. If El Paso Field Services does not exercise this repurchase right, it must pay us a forfeiture penalty. If El Paso Field Services does exercise this repurchase right, our rights and obligations under the 20-year agreement, including our right to a fixed fee for each dekatherm of natural gas processed at the Chaco plant will remain in place for the term of the agreement and will expire upon the termination of the agreement.

Our offshore oil pipeline systems were built as a result of the need for additional crude oil capacity to transport new deepwater oil production to shore. Our principal competition includes other oil pipeline systems, built, owned and operated by producers to handle their own production and, as capacity is available, production for others. Our oil pipelines compete for new production on the basis of geographic proximity to the production, cost of connection, available capacity, transportation rates and access to onshore markets. In addition, the ability of our pipelines to access future reserves will be subject to our ability, or the producers' ability, to fund the significant capital expenditures required to connect to the new production.

A substantial portion of the revenues generated by our oil pipelines systems are attributed to production from reserves committed under long-term contracts for the productive life of the relevant field. Nonetheless, these reserves and other reserves that may become available to our pipeline systems are depleting assets and will be produced over a finite period. Each of our pipeline systems must access additional reserves to offset the natural decline in production from existing connected wells or the loss of any other production to a competitor. Furthermore, the rates we charge for our services are dependent on the quality of the service required by the customer and the amount and term of the reserve commitment by the customer. A majority of our offshore arrangements involve life-of-reserve commitments with both firm and interruptible components. Generally, we receive a price per barrel of oil or water handled.

Regulatory Environment

Our offshore oil pipeline systems are subject to regulation under the Outer Continental Shelf Lands Act, which calls for nondiscriminatory transportation on pipelines operating in the outer continental shelf region of the Gulf of Mexico. All of our oil pipeline systems are subject to the National Environmental Policy Act and other environmental legislation. Each of the oil pipeline systems has a continuing program of inspection designed to keep all of our facilities in compliance with pollution control and pipeline safety requirements. We believe that our oil pipeline systems are in compliance with the applicable requirements of these regulations.

Maintenance

Each of our pipeline systems, our fractionation facilities and our processing facilities require regular maintenance. The interior of the EPN Texas, Allegheny and Poseidon pipelines is maintained through the regular cleaning of the line of liquids that collect in the pipeline. Corrosion inhibitors are also injected into all of the systems through the flow stream on a continuous basis. Our Allegheny and Poseidon oil pipeline systems include platforms that are manned on a continuous basis. The personnel on board these platforms are responsible for site maintenance, operations of the platform facilities, measurement of the oil stream at the source of production and corrosion control. Our Chaco processing facility is manned on a continuous basis by personnel who are also responsible for maintenance and operations. The maintenance of the facility is an ongoing process, which is performed based on the hours of operation, oil analysis and vibration hours. Shutdown of the Chaco plant is not required for regular maintenance activity.

PLATFORMS

Offshore platforms are critical components of the offshore infrastructure in the Gulf of Mexico, supporting drilling and production operations, and therefore play a key role in the overall development of offshore oil and natural gas reserves. Platforms are used to:

- interconnect the offshore pipeline grid;

- provide an efficient means to perform pipeline maintenance;

- locate compression, separation, production handling and other facilities; and

- conduct drilling operations during the initial development phase of an oil and natural gas property.

We have interests in six multi-purpose offshore platforms in the Gulf of Mexico, including five multi-purpose hub-platforms and one multi-purpose TLP in the Prince Field, which was installed in July 2001 and accepted initial production in September 2001. These platforms were specifically designed to be used as deepwater hubs and production handling and pipeline maintenance facilities. Through these facilities, we are able to provide a variety of midstream services to increase deliverability and attract new volumes into our offshore pipeline systems. The following table and discussions describe our platforms.

	EAST CAMERON 373	VIOSCA KNOLL 817	SHIP SHOAL 331(1)	GARDEN BANKS 72	SHIP SHOAL 332(2)	PRINCE TLP
Ownership interest	100%	100%	100%	100%	50%	50%
In-service date	2001	1998	1995	1994	1995	1985
Water depth (in feet)	1,450	441	671	376	518	438
Acquired (A) or constructed (C)	C	C	C	A	C	A
Approximate handling capacity:						
Natural gas (MMcf/d)	80	110	140	--	80	150
Oil and condensate (MBbls/d)	50	5	5	--	55	12

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(1) The Ship Shoal 331 platform is currently used as a satellite landing area. All products transported to the Ship Shoal 331 platform are processed on the Ship Shoal 332 platform.

(2) We sold 50 percent of our interest in the Ship Shoal 332 platform in January 2001.

Prince TLP. In July 2001, we placed in service our newly-constructed Prince TLP. The Prince TLP has a state-of-the-art design, which accommodates a workover rig and four to five wellhead connections above sea level and up to three subsea wellhead connections. El Paso Production, a subsidiary of El Paso Corporation, has committed all of the oil and natural gas it produces from the Prince Field to our Prince TLP and related pipelines and separating and handling facilities, for which we receive a fixed monthly demand charge as well as a commodity charge for the volumes of natural gas, oil and water produced from the Prince Field. The Prince TLP has the capacity to accommodate a 1,200-horsepower completion rig. The deck is equipped for the future addition of numerous sub-sea well tie-backs. First production flowed through the Prince TLP in September 2001. As part of our pending agreement to acquire assets from El Paso Corporation in the first quarter of 2002, we agreed to sell the Prince TLP to a subsidiary of El Paso Corporation.

East Cameron 373. The East Cameron 373 platform is located at the south end of the central leg of Shell's Stingray pipeline system. The platform serves as the host for Kerr-McGee Corporation's East Cameron Block 373 production and as the landing site for Garden Banks Blocks 108, 152 and 200 production.

Viosca Knoll 817. The Viosca Knoll 817 platform is centrally located on the Viosca Knoll system. The platform serves as a base for landing deepwater production in the area, including ExxonMobil's, Shell's, and BP's Ram Powell development. A 7,000 horsepower compressor on the platform facilitates deliveries from the Viosca Knoll system to multiple downstream interstate pipelines. The platform is also used as a base for oil and natural gas production from our Viosca Knoll Block 817 lease.

Ship Shoal 331. The Ship Shoal 331 platform is a production facility located approximately 75 miles off the coast of Louisiana. Pogo Producing Company has rights to utilize the platform pursuant to a production handling and use of space agreement.

Garden Banks 72. The Garden Banks 72 platform is located at the south end of the eastern leg of Shell's Stingray pipeline system and serves as the western-most termination point of the Poseidon system. The platform serves as a base for landing deepwater production from Enterprise Oil Gulf of Mexico, Inc.'s and Devon Energy Inc.'s Garden Banks Block 161 development and Mariner Energy Inc.'s development in Garden Banks Block 73, and will serve as the host for Amerada Hess Corporation's Garden Banks Block 158 development. We also use this platform as the host for our Garden Banks Block 72 production and the landing site for production from our Garden Banks Block lease located in an adjacent lease block.

Ship Shoal 332. The Ship Shoal 332 platform serves as a major junction platform for pipelines in the Allegheny and Poseidon systems.

Markets and Competition

Our platforms are subject to similar competitive factors as our natural gas and oil pipeline systems. These assets generally compete on the basis of proximity and access to existing reserves and pipeline systems, as well as costs and rates. Furthermore, competitors to these platforms may possess greater technical skill and capital resources than we have.

Maintenance

Each of our platforms requires regular maintenance. The platforms are painted to the waterline every three to five years to prevent atmospheric corrosion. Corrosion protection devices are also fastened to platform legs below the waterline to prevent corrosion. Remotely operated vehicles or divers inspect the platforms below the waterline generally every five years. Most of our platforms are manned on a continuous basis. The personnel on board these platforms are responsible for site maintenance, operations of the platform facilities, measurement of the oil and natural gas stream at the source of production and corrosion control.

NATURAL GAS STORAGE

We own the Crystal salt dome natural gas storage businesses located in Mississippi, which are strategically situated to serve the Northeast, Mid-Atlantic and Southeast natural gas markets. The two primary facilities, Petal and Hattiesburg, have a combined current working capacity of 6.7 Bcf, and are capable of delivering in excess of 670 MMcf/d of natural gas into three interstate pipeline systems: Gulf South Pipeline, Transco, and Tennessee Gas Pipeline. Each of these facilities is capable of making deliveries at the high rates necessary to satisfy peaking requirements in the electric generation industry.

The Hattiesburg facility is comprised of 73 acres outside of Hattiesburg, Mississippi, and consists of three salt caverns with a working gas capacity of approximately 3.5 Bcf. The Petal facility is comprised of 16.5 acres, is less than one mile from the Hattiesburg facility and consists of a single high-deliverability natural gas storage cavern with a working gas capacity of approximately 3.2 Bcf. The Petal facility is designed to provide up to 320 MMcf/d of 10-day storage services with the capability of being refilled in 20 days. The Petal capacity is currently fully subscribed, primarily with short-term contracts. The Hattiesburg facility has an injection capacity in excess of 175 MMcf/d of natural gas and a withdrawal capacity in excess of 350 MMcf/d of natural gas. The Hattiesburg capacity is currently fully subscribed, primarily with long-term contracts expiring between 2005 and 2006. The ability of these facilities to handle high levels of injections and withdrawals of natural gas makes the facilities well suited for customers who desire the ability to meet short duration load swings and to cover major supply interruption events, such as hurricanes and temporary losses of production. The high injection and withdrawal rates also allow customers to take advantage of price savings in natural gas by allowing for quick delivery. The characteristics of the salt domes at the facilities permit sustained periods of high delivery, the ability to quickly switch from full injection to full withdrawal and the ability to provide an impermeable storage medium.

The FERC has approved a 6.8 Bcf expansion of the Petal facility, as well as a 60-mile pipeline addition that will interconnect with the storage facility and offer direct interconnects with the Southern Natural Gas, Transco and Destin pipeline systems. The additional Petal capacity is dedicated under a 20-year fixed-fee contract to a subsidiary of The Southern Company, one of the largest producers of electricity in the United States. We expect to complete the first-phase of the Petal facility expansion and the construction of the pipeline addition in mid-2002.

Markets and Competition

Competition for natural gas storage is primarily based on location and the ability to deliver natural gas in a timely and reliable manner. Our Petal and Hattiesburg natural gas storage facilities are located in an area in Mississippi that can effectively service the Northeastern, Mid-Atlantic and Southeastern natural gas markets, and the facilities have the ability to deliver all of their stored natural gas within a short timeframe. Our natural gas storage facilities compete with other means of natural gas storage, including other salt dome storage facilities, depleted reservoir facilities, liquified natural gas and pipelines.

Most of the contracts relating to our Hattiesburg natural gas storage assets are long term, expiring between 2005 and 2006. We believe that the existence of these long-term contracts for storage, the proposed expansion of our operations and the location of our natural gas storage facilities should allow us to compete effectively with other companies who provide natural gas storage services. We believe that many of our natural gas storage contracts will be renewed, although we also expect that once these firm storage contracts have expired, we will experience greater competition for providing storage services. The competition we experience will be dependent upon the nature of the natural gas storage market existing at that time. In addition to long-term contracts, we actively market interruptible storage services at the Petal facility to enhance our revenue generating ability beyond the firm storage contracts.

Regulatory Environment

Our Hattiesburg facility is a regulated utility under the jurisdiction of the Mississippi Public Service Commission. Accordingly, the rates charged for natural gas storage services are subject to approval from this agency. The present rates of the firm long-term contracts for natural gas storage in the Hattiesburg facility were approved in 1990. A portion of its natural gas storage business is also subject to a limited jurisdiction certificate issued by FERC. The certificate authorizes us to provide natural gas storage services that may be ultimately consumed outside of Mississippi. Our Petal facility is subject to regulation under the Natural Gas Act of 1938, as amended, and to the jurisdiction of FERC. The Petal facility currently holds certificates of public convenience and necessity which permit it to charge market based rates. The natural gas pipeline industry has historically been heavily regulated by federal and state government and we cannot predict what further actions FERC, state regulators, or federal and state legislators may take in the future.

In September 2001, FERC issued a NOPR that proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. Since Petal is an interstate facility as defined by the Natural Gas Act, the proposed regulations, if adopted by FERC, would dictate how Petal conducts business and interacts with all energy affiliates of El Paso Corporation and us. We cannot predict the outcome of the NOPR, but adoption of the regulations in substantially the form proposed would, at a minimum, place administrative and operational burdens on us. Further, more fundamental changes could be required such as a complete organizational separation or sale of Petal.

OIL AND NATURAL GAS PRODUCTION

Currently, we own interests in six oil and natural gas properties located in waters offshore of Louisiana. Production is gathered, transported, and processed through our pipeline systems and platform facilities and is sold to various third parties and subsidiaries of El Paso Corporation.

Producing Properties

	GARDEN BANKS BLOCK 72	GARDEN BANKS BLOCK 73(1)	GARDEN BANKS BLOCK 117	VIOSCA KNOLL BLOCK 817(2)	WEST DELTA BLOCK 35(3)	PRINCE FIELD(4)
Working interest........	50%	--	50%	100%	38%	--
Net revenue interest....	40.2%	2.5%	37.5%	80%	29.8%	9.0%
In-service date.........	1996	2000	1996	1995	1993	2001
Net acres...............	2,880	--	2,880	5,760	1,894	--
Distance offshore (in miles)............	120	115	120	40	10	120
Water depth (in feet)...	518	743	1,000	671	60	1,450
Producing wells.........	5	1	2	7	3	2
Cumulative production:						
Natural gas (MMcf)....	4,565	219	2,056	61,589	2,174	32
Oil (MBbls)...........	1,387	--	1,146	142	14	37

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(1) We own a 2.5 percent overriding interest in Garden Banks Block 73, which began producing in mid 2000.

(2) Our working interest in Viosca Knoll Block 817 is subject to a production payment that entitles holders to 25 percent of the proceeds from the production attributable to this working interest (after deducting all leasehold operating expenses, including platform access and production handling fees) until the holders have received the aggregate sum of $16 million. At December 31, 2001, the unpaid portion of the production payment obligation totaled $9.4 million.

(3) The West Delta Block 35 field commenced production in 1993, but our interest in this field was acquired in connection with El Paso Corporation's acquisition of our general partner in 1998. Production data is for the period from August 1998.

(4) We own a 9 percent net overriding royalty interest in the Prince Field.

We currently own a 9 percent net overriding royalty interest in the Prince Field, formerly the Ewing Bank 958 Unit. Production from the Prince Field, which is committed to our Prince TLP, commenced in September 2001. As part of our pending agreement to acquire assets from El Paso Corporation in the first quarter of 2002, we agreed to sell this overriding royalty interest to a subsidiary of El Paso Corporation.

Acreage and Wells. The following table sets forth our developed and undeveloped oil and natural gas acreage as of December 31, 2001. Undeveloped acreage refers to those lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether or not such acreage contains proved reserves. Gross acres in the following table refer to the number of acres in which a working interest is owned directly by us. The number of net acres is our fractional ownership of the working interest in the gross acres.

	GROSS	NET
Developed acreage	4,872	3,576
Undeveloped acreage	23,153	14,518
Total acreage	28,025	18,094

Our gross and net ownership in producing wells in which a working interest is owned directly by us at December 31, 2001, is as follows:

	GROSS	NET
Natural gas	11.0	8.6
Oil	6.0	3.0
Total	17.0	11.6

We participated through our 38 percent non-operating working interest in a developmental well in West Delta Block 35 in 2001. As an operator, we have not drilled any exploratory or developmental wells since 1998 and do not intend to drill any development or exploratory wells in the future.

Net Production, Unit Prices and Production Costs

The following table sets forth information regarding the production volumes of, average unit prices received for, and average production costs for our oil and natural gas properties for the years ended December 31:

	OIL (MBBLS)			NATURAL GAS (MMCF)		
	2001	2000	1999	2001	2000	1999
Net production(1)	343	295	357	4,038	7,185	12,211
Average realized sales price(1)	$23.47	$25.26	$14.32	$ 4.52	$ 1.86	$ 2.02
	(Restated)	(Restated)	(Restated)	(Restated)	(Restated)	(Restated)
Average segment realized production costs(2)	$16.11	$10.87	$ 7.36	$ 2.68	$ 1.81	$ 1.23

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(1) The information regarding net production and average realized sales prices includes overriding royalty interests. Average realized oil and natural gas sales prices for 2000 and 1999 were impacted by hedging activities. Excluding our hedging activities, our average realized sales price would have been $28.12 for oil and $3.91 for natural gas in 2000 and $16.14 for oil and $2.16 for natural gas in 1999.

(2) The components of average segment realized production costs, which consist of production expenses per unit of oil or natural gas produced, may vary substantially among wells depending on the methods of recovery employed and other factors. Our production expenses include third party transportation expenses, maintenance and repair, labor and utilities costs, as well as the cost of platform access fees paid by our oil and natural gas subsidiary, included in our oil and natural gas production segment, to subsidiaries included in our platforms segment. These platform access fees are eliminated in our consolidated financial statements. For each of the years presented, these platform access fees were approximately $10 million. On a consolidated basis our average realized production costs were as follows:

OIL (MBBLS)

				NATURAL GAS (MMCF)		
	2001	2000	1999	2001	2000	1999
Average consolidated realized production costs............	$6.35	$4.23	$3.22	$1.06	$0.70	$0.54

The increase in per unit production costs from year to year was a result of production decline coupled with higher offshore oil and natural gas field servicing and direct production costs.

The relationship between average sales prices and average production costs depicted by the table above is not necessarily indicative of true results of operations. For a discussion of oil and natural gas reserve information and estimated future net cash flows, see Item 8, Financial Statements and Supplementary Data, Note 16.

Markets and Competition

We are reducing our oil and natural gas production activities due to its higher risk profile, including risks associated with finding production and commodity prices. Accordingly, our focus is to maximize the production from our existing portfolio of oil and natural gas properties. As a result, the competitive factors that would normally impact exploration and production activities are not as pertinent to our operations. However, the oil and natural gas industry is intensely competitive, and we do compete with a substantial number of other companies, including many with larger technical staffs and greater financial and operational resources in terms of accessing transportation, hiring personnel, marketing production and withstanding the effects of general and industry-specific economic changes.

Regulatory Environment

Our production and development operations are subject to regulation at the federal and state levels. Regulated activities include:

- requiring permits for the drilling of wells;

- maintaining bonds and insurance requirements in order to drill or operate wells;

- drilling and casing wells;

- the surface use and restoring of properties upon which wells are drilled; and

- plugging and abandoning of wells.

Our production and development operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the density of wells that may be drilled, the levels of production, and the pooling of oil and natural gas properties.

We presently have interests in, or rights to, offshore leases located in federal waters. Federal leases are administered by the Minerals Management Service (MMS). Individuals and entities must qualify with the MMS prior to owning and operating any leasehold or right-of-way interest in federal waters. Qualification with the MMS generally involves filing certain documents and obtaining an area-wide performance bond and/or supplemental bonds representing security for facility abandonment and site clearance costs.

Operating Environment

Our oil and natural gas production operations are subject to all of the operating risks normally associated with the production of oil and natural gas, including blowouts, cratering, pollution and fires, each of which could result in damage to life or property. Offshore operations are subject to usual marine perils, including hurricanes and other adverse weather conditions, and governmental regulations, including interruption or termination by governmental authorities based on environmental and other considerations. In accordance with customary industry practices, we maintain broad insurance coverage with respect to potential losses resulting from these operating hazards.

MAJOR ENCUMBRANCES

Substantially all of our assets, with the exception of Argo, L.L.C., and Argo I, L.L.C., together with our management agreement, and our general partner's one percent general partner interest, are pledged as collateral under our existing revolving credit facility. Substantially all of Argo's assets are pledged under Argo's limited recourse term loan. In addition, Poseidon, our equity investee, currently has a credit facility under which substantially all of its assets are pledged. For a discussion of our credit facilities, see Item 8, Financial Statements and Supplementary Data, Note 6.

ENVIRONMENTAL

A description of our environmental matters is included in Item 8, Financial Statements and Supplementary Data, Note 10.

EMPLOYEES

Employees of El Paso Corporation, through our general partner, perform all of our administrative and operational activities under a management agreement. Therefore, we had no direct employees at December 31, 2001. We reimburse our general partner for all reasonable general and administrative expenses and other reasonable expenses incurred by our general partner and its affiliates for, or on our behalf, including, but not limited to, expenses incurred by our general partner under this management agreement.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

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

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Operating revenues			
Gathering and transportation services	$ 93,550	$ 63,499	$ 20,282
Liquid transportation and handling	39,460	8,307	2,029
Platform services	23,538	13,875	11,383
Natural gas storage services	19,373	6,182	--
Oil and natural gas sales	26,310	20,552	29,965
	202,231	112,415	63,659
Operating expenses			
Cost of natural gas	51,542	28,160	--
Operation and maintenance, net	35,548	14,461	22,402
Depreciation, depletion and amortization	38,649	27,743	30,630
Asset impairment charge	3,921	--	--
	129,660	70,364	53,032
Operating income	72,571	42,051	10,627
Other income (loss)			
Earnings from unconsolidated affiliates	8,449	22,931	32,814
Net (loss) gain on sale of assets	(11,367)	--	10,103
Other income	28,726	2,377	358
	25,808	25,308	43,275
Income before interest, income taxes and other charges	98,379	67,359	53,902
Interest and debt expense	43,130	47,072	35,323
Minority interest	100	95	197
Income tax benefit	--	(305)	(435)
	43,230	46,862	35,085
Net income	55,149	20,497	18,817
Net income allocated to general partner	24,661	15,578	12,129
Net income allocated to Series B unitholders	17,228	5,668	--
Net income (loss) allocated to limited partners before accounting change	13,260	(749)	6,688
Cumulative effect of accounting change	--	--	(15,427)
Net income (loss) allocated to limited partners	$ 13,260	$ (749)	$ (8,739)
Basic and diluted net income (loss) per unit before accounting change	$ 0.38	$ (0.03)	$ 0.26
Cumulative effect of accounting change	--	--	(0.60)
Basic and diluted net income (loss) per unit after accounting change	$ 0.38	$ (0.03)	$ (0.34)
Weighted average basic and diluted units outstanding	34,376	29,077	25,928

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS)

DECEMBER 31,	2001	2000
ASSETS		
Current assets		
Cash and cash equivalents	$ 13,084	$ 20,281
Accounts receivable, net		
Trade	33,162	33,801
Affiliates	22,863	1,602
Other current assets	557	633
Total current assets	69,666	56,317
Property, plant and equipment, net	1,103,427	619,238
Investment in processing agreement	119,981	--
Investments in unconsolidated affiliates	34,442	182,734
Other noncurrent assets	29,754	11,182
Total assets	$1,357,270	$869,471
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable		
Trade	$ 14,987	$ 14,726
Affiliates	9,918	2,368
Accrued interest	6,401	3,107
Current maturities of limited recourse term loan	19,000	--
Other current liabilities	4,159	2,171
Total current liabilities	54,465	22,372
Revolving credit facility	300,000	318,000
Long-term debt	425,000	175,000
Limited recourse term loan, less current maturities	76,000	45,000
Other noncurrent liabilities	1,079	394
Total liabilities	856,544	560,766
Commitments and contingencies		
Minority interest	--	(2,366)
Partners' capital		
Limited partners		
Series B preference units; 125,392 units in 2001 and 170,000 units in 2000 issued and outstanding	142,896	175,668
Common units; 39,738,974 units in 2001 and 31,550,314 units in 2000 issued and outstanding	354,019	132,802
Accumulated other comprehensive income allocated to limited partners' interest	(1,259)	--
General partner	5,083	2,601
Accumulated other comprehensive income allocated to general partner's interests	(13)	--
Total partners' capital	500,726	311,071
Total liabilities and partners' capital	$1,357,270	$869,471

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Cash flows from operating activities			
Net income	$ 55,149	$ 20,497	$ 18,817
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	38,649	27,743	30,630
Net loss (gain) on sale of assets	11,367	--	(10,103)
Asset impairment charge	3,921	--	--
Distributed earnings of unconsolidated affiliates			
Earnings from unconsolidated affiliates	(8,449)	(22,931)	(32,814)
Distributions from unconsolidated affiliates	35,062	33,960	46,180
Litigation reserve	--	(2,250)	2,250
Other noncash items	4,308	2,237	1,834
Working capital changes, net of effects of acquisitions and non-cash transactions			
Accounts receivable	(41,954)	(17,351)	2,107
Other current assets	125	1,295	366
Accounts payable, accrued interest and other current liabilities	(259)	5,210	(8,507)
Noncurrent receivable from El Paso Corporation	(10,362)	--	--
Other	(173)	--	--
Net cash provided by operating activities	87,384	48,410	50,760
Cash flows from investing activities			
Acquisition and development of oil and natural gas properties	(2,018)	(172)	(3,218)
Additions to pipelines, platforms and facilities	(576,907)	(90,205)	(30,662)
Investments in unconsolidated affiliates	(1,487)	(8,979)	(59,348)
Cash paid for acquisitions, net of cash acquired	(28,414)	(26,476)	(20,351)
Proceeds from sale of assets	109,126	--	26,122
Distributions related to the formation of Deepwater Holdings	--	--	20,000
Other	--	(381)	322
Net cash used in investing activities	(499,700)	(126,213)	(67,135)
Cash flows from financing activities			
Net proceeds from revolving credit facility	559,994	152,043	141,126
Repayments of revolving credit facility	(581,000)	(125,000)	(226,850)
Net proceeds from issuance of long-term debt	243,032	--	168,878
Net proceeds from limited recourse term loan	49,960	43,554	--
Net proceeds from issuance of common units	286,699	100,634	--
Redemption of Series B preference units	(50,000)	--	--
Redemption of publicly held preference units	--	(804)	--
Contributions from general partner	2,843	2,785	603
Distributions to partners	(106,409)	(79,330)	(66,288)
Net cash provided by financing activities	405,119	93,882	17,469
Net (decrease) increase in cash and cash equivalents	(7,197)	16,079	1,094
Cash and cash equivalents at beginning of year	20,281	4,202	3,108
Cash and cash equivalents at end of year	$ 13,084	$ 20,281	$ 4,202

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(IN THOUSANDS)

SERIES B SERIES B PREFERENCE PREFERENCE PREFERENCE PREFERENCE COMMON COMMON GENERAL UNITS UNITHOLDERS UNITS UNITHOLDERS UNITS UNITHOLDERS PARTNER(1) TOTAL ---------- ---------- ---------- ----------- ------- ----------- ---------- --------- Partners' capital at December 31, 1998........ -- $ -- 1,017 $ 7,351 23,350 $ 90,972 $(15,427) $ 82,896 Cumulative effect of accounting change........ -- -- -- 3,072 -- (18,499) 15,427 -- Net income(2)............. -- -- -- 919 -- 5,769 12,129 18,817 Acquisition of additional interest in Viosca Knoll.................... -- -- -- -- 2,662 59,792 -- 59,792 General partner contribution related to issuance of common units.................... -- -- -- -- -- -- 603 603 Conversion of preference units into common units.................... -- -- (727) (7,454) 727 7,454 -- -- Cash distributions......... -- -- -- (919) -- (52,211) (12,489) (65,619) ------- ------- - ------- --------- ------ -------- -------- --------- Partners' capital at December 31, 1999........ -- -- 290 2,969 26,739 93,277 243 96,489 Net income (loss) (2)....... -- 5,668 -- 241 -- (990) 15,578 20,497 Conversion of preference units into common units.................... -- -- (211) (2,165) 211 2,165 -- -- Redemption of remaining preference units......... -- -- (79) (804) -- -- -- (804) Issuance of common units... -- -- -- -- 4,600 100,634 -- 100,634 General partner contribution related to the issuance of common units.................... -- -- -- -- -- -- 2,785 2,785 Issuance of Series B preference

units......... 170
170,000 -- -- -- -- --
170,000 Cash
distributions.........
(241) -- (62,284)
(16,005) (78,530) ------
- -------- ------- -----
---- ------ -------- ---
----- ---------
Partners' capital at
December 31,
2000........ 170 175,668
-- -- 31,550 132,802
2,601 311,071 Net
income(2)..............
-- 17,228 -- -- --
13,260 24,661 55,149
Accumulated other
comprehensive income
(loss)...................
-- -- -- -- -- (1,259)
(13) (1,272) Issuance of
common units... -- -- --
-- 8,189 286,699 --
286,699 Unamortized unit
option
compensation.............
-- -- -- -- -- 2,161 --
2,161 Redemption of
Series B preference
units......... (45)
(50,000) -- -- -- -- --
(50,000) General partner
contribution related to
the issuance of common
units...................
-- -- -- -- -- -- 2,843
2,843 Cash
distributions......... -
- -- -- -- -- (80,903)
(25,022) (105,925) -----
-- -------- ------- ----
----- ------ -------- --
------ ---------
Partners' capital at
December 31,
2001........ 125
$142,896 -- $ -- 39,739
$352,760 $ 5,070 $
500,726 ======= ========
======= ========= ======
======== ========
=========

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(1) El Paso Energy Partners Company, a wholly owned subsidiary of El Paso
Corporation, owns a one percent general partner interest in us.
(2) Income allocation to our general partner includes both its incentive
distributions and its one percent ownership interest.

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
(IN THOUSANDS)

COMPREHENSIVE INCOME

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Net income	$55,149	$20,497	$18,817
Other comprehensive income (loss)	(1,272)	--	--
Total comprehensive income	$53,877	$20,497	$18,817

ACCUMULATED OTHER COMPREHENSIVE INCOME

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Beginning balance	$ --	$ --	$ --
Unrealized mark-to-market losses arising during period	(1,682)	--	--
Reclassification adjustments for changes in initial value of derivative instruments to settlement date	410	--	--
Ending balance	$(1,272)	$ --	$ --

See accompanying notes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

We are a publicly held Delaware master limited partnership established in 1993 for the purpose of providing midstream energy services, including gathering, transportation, fractionation, storage and other related activities for producers of natural gas and oil, onshore and offshore in the Gulf of Mexico. As of December 31, 2001, we had 39,738,974 common units representing limited partner interests and 125,392 Series B preference units representing preference interests outstanding. On that date, the public owned 29,308,140 common units, or 74 percent of our outstanding common units, and El Paso Corporation, through its subsidiaries, owned 10,430,834 common units, or 26 percent of our outstanding common units, all of the 125,392 Series B preference units (with a liquidation value of $143 million) and our one percent general partner interest.

Basis of Presentation and Principles of Consolidation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. We account for investments in companies where we have the ability to exert significant influence over, but not control over operating and financial policies, using the equity method of accounting. Prior to May 2001, our general partner's approximate one percent non-managing interest in twelve of our subsidiaries represented the minority interest in our consolidated financial statements. In May 2001, we purchased our general partner's one percent non-managing ownership interests. Our consolidated financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications have no impact on reported net income or partners' capital.

Use of Estimates

The preparation of our financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities that exist at the date of our financial statements. While we believe our estimates are appropriate, actual results can, and often do, differ from those estimates.

Accounting for Regulated Operations

Our HIOS interstate natural gas system and our Petal storage facility are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each system operates under separate FERC approved tariffs that establish rates, terms and conditions under which each system provides services to its customers. Our businesses that are subject to the regulations and accounting requirements of FERC have followed the accounting requirements of Statement of Financial Accounting Standard (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation, which may differ from the accounting requirements of our non-regulated entities. Transactions that have been recorded differently as a result of regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects, and other costs and taxes included in, or expected to be included in, future rates.

When the accounting method followed is required by or allowed by the regulatory authority for rate-making purposes, the method conforms to the generally accepted accounting principle of matching costs with the revenues to which they apply.

Cash and Cash Equivalents

We consider short-term investments with little risk of change in value because of changes in interest rates and purchased with an original maturity of less than three months to be cash equivalents.

Allowance for Doubtful Accounts

We have established an allowance for losses on accounts which may become uncollectible. Collectibility is reviewed regularly and the allowance is adjusted as necessary, primarily under the specific identification method. At December 31, 2001 and 2000, the allowance was $1.8 and $0.4 million.

Natural Gas Imbalances

Natural gas imbalances result from differences in gas volumes received from and delivered to our customers and arise when a customer delivers more or less gas into our pipelines than they take out. These imbalances are settled in kind through a fuel gas and unaccounted for gas tracking mechanism, negotiated cash-outs between parties, or are subject to a cash-out procedure. Gas imbalances are reflected in accounts receivable or accounts payable, as appropriate, in our financial statements.

Property, Plant and Equipment

For our regulated interstate system and storage facility we use the composite (group) method to depreciate regulated property, plant and equipment. Under this method, assets with similar lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate approved in our tariff, to the total cost of the group, until its net book value equals its estimated salvage value.

Our non-regulated gathering pipelines, platforms and related facilities, processing facilities and equipment, and storage facilities and equipment are recorded at cost and are depreciated on a straight-line basis over the estimated useful lives which are as follows:

Gathering pipelines..	5-30 years
Platforms and facilities..................................	18-30 years
Processing facilities......................................	25-30 years
Storage facilities...	25-30 years

Repair and maintenance costs are expensed as incurred, while additions, improvements and replacements are capitalized.

We account for our oil and natural gas exploration and production activities using the successful efforts method of accounting. Under this method, costs of successful exploratory wells, developmental wells and acquisitions of mineral leasehold interests are capitalized. Production, exploratory dry hole and other exploration costs, including geological and geophysical costs and delay rentals, are expensed as incurred. Unproved properties are assessed periodically and any impairment in value is recognized currently as depreciation, depletion and amortization expense.

Depreciation, depletion and amortization of the capitalized costs of producing oil and natural gas properties, consisting principally of tangible and intangible costs incurred in developing a property and costs of productive leasehold interests, are computed on the unit-of-production method. Unit-of-production rates are based on annual estimates of remaining proved developed reserves or proved reserves, as appropriate, for each property.

Estimated dismantlement, restoration and abandonment costs and estimated residual salvage values are taken into account in determining depreciation provisions for gathering pipelines, platforms, related facilities and oil and natural gas properties.

Retirements, sales and disposals of assets are recorded by eliminating the related costs and accumulated depreciation, depletion and amortization of the disposed assets with any resulting gain or loss reflected in income.

Asset Impairment

We evaluate the impairment of assets in accordance with SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of. If an adverse event or change in circumstances occurs, we make an estimate of our future cash flows from our assets, grouped together at the lowest level for which separate cash flows can be measured, to determine if the asset is impaired. If the total of the undiscounted future cash flows is less than the carrying amount for the assets, we calculate the fair value of the assets either through reference to similar asset sales, or by estimating the fair value using a discounted cash flow approach. These cash flow estimates require us to make estimates and assumptions for many years into the future for pricing, demand, competition, operating costs, legal, regulatory and other factors. On January 1, 2002, we adopted the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. A discussion of this pronouncement follows at the end of this note.

Capitalization of Interest

Interest and other financing costs are capitalized in connection with construction and drilling activities as part of the cost of the asset and amortized over the related asset's estimated useful life.

Debt Issue Costs

Debt issue costs are capitalized and amortized over the life of the related indebtedness using the effective interest method. Any unamortized debt issue costs are expensed at the time the related indebtedness is repaid or terminated.

Revenue Recognition

Revenue from pipeline transportation of hydrocarbons is recognized upon receipt of the hydrocarbons into the pipeline systems. Revenue from natural gas sales is recognized upon delivery and was $59.7 million and $34.5 million for the years ended December 31, 2001 and 2000. There were no natural gas sales in 1999. Natural gas sales are included in gathering and transportation services revenue on the accompanying statements of income. Natural gas storage revenues and platform access revenues consist primarily of fixed fees for capacity reservation and some of our transportation contracts on our Viosca Knoll system and our Indian Basin lateral also contain a fixed fee to reserve transportation capacity. These fixed fees are recognized during the month in which the capacity is reserved by the customer, regardless of how much capacity is actually used. Revenue from processing services and fractionation services is recognized in the period the services are provided. Interruptible revenues from natural gas storage, which are generated by providing excess storage capacity, are variable in nature and are recognized when the service is provided.

Environmental Costs

Expenditures for ongoing compliance with environmental regulations that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, and which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated.

Accounting for Price Risk Management Activities

Our business activities expose us to a variety of risks, including commodity price risk and interest rate risk. From time to time we use derivative instruments to manage these risks. Beginning in 2001, we record all derivative instruments on the balance sheet at their fair value under the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities.

For those instruments entered into to hedge risk and which qualify as hedges, we apply the provisions of SFAS No. 133, and the accounting treatment depends on each instrument's intended use and how it is designated. In addition to its designation, a hedge must be effective. To be effective, changes in the value of the derivative or its resulting cash flows must substantially offset changes in the value or cash flows of the item being hedged.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategies for undertaking various hedge transactions. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair values of the hedged items. We discontinue hedge accounting prospectively if we determine that a derivative is not highly effective as a hedge.

During 2001, we entered into cash flow hedges that qualify for SFAS No. 133 treatment. Changes in the fair value of a derivative designated as a cash flow hedge are recorded in accumulated other comprehensive income for the portion of the change in value of the derivative that is effective. The ineffective portion of the derivative is recorded in earnings in the current period. Classification in the income statement of the ineffective portion is based on the income classification of the item being hedged.

We may also purchase and sell instruments to economically hedge price fluctuations in the commodity markets. These instruments are not documented as hedges due to their short-term nature, or do not qualify under the provisions of SFAS No. 133 for hedge accounting due to the terms in the instruments. Where such derivatives do not qualify, changes in their fair value are recorded in earnings in the current period.

In 1999 and 2000, we entered into commodity price swap instruments for non-trading purposes to manage our exposure to price fluctuations on anticipated natural gas and crude oil sales transactions. To qualify for hedge accounting, prior to our adoption of SFAS No. 133, the transactions must have reduced the price risk of the underlying hedged items, be designated as hedges at inception, and resulted in cash flows and financial impacts which were inversely correlated to the position being hedged. If correlation ceased to exist, hedge accounting was terminated and mark-to-market accounting was applied. Gains and losses resulting from hedging activities and the termination of any hedging instruments were initially deferred and included as an increase or decrease to oil and natural gas sales in the period in which the hedged production was sold.

During the normal course of our business, we may enter into contracts that qualify as derivatives under the provisions of SFAS No. 133. As a result, we evaluate our contracts to determine whether derivative accounting is appropriate. Contracts that meet the criteria of a derivative and qualify as "normal purchases" and "normal sales", as those terms are defined in SFAS No. 133, may be excluded from SFAS No. 133 treatment.

Income Taxes

As of December 31, 2001, neither we nor any of our subsidiaries are taxable entities. Tarpon Transmission Company, our only taxable entity in 2000 and 1999, was sold in January 2001, and as a result, we incurred no tax liability in 2001. However, the taxable income or loss resulting from our operations will ultimately be included in the federal and state income tax returns of the general and limited partners. Individual partners will have different investment bases depending upon the timing and price of their acquisition of partnership units. Further, each partner's tax accounting, which is partially dependent upon his tax position, may differ from the accounting followed in the consolidated financial statements. Accordingly, there could be significant differences between each individual partner's tax basis and his share of the net assets reported in the consolidated financial statements. We do not have access to information about each individual partner's tax attributes and the aggregate tax bases cannot be readily determined.

We utilized SFAS No. 109, Accounting for Income Taxes, to account for Tarpon's income taxes subject to federal corporate income taxation. The income tax benefit reported in our consolidated statements of income for the years ended 2000 and 1999 relates solely to Tarpon's book loss at the effective statutory income tax rate for the respective period since no material differences exist between book and taxable income. In January 2001, we sold our interest in Tarpon as a result of a FTC order. All of Tarpon's deferred tax liabilities were assumed by the buyer at the time of sale.

Income (Loss) per Unit

Basic income (loss) per unit excludes dilution and is computed by dividing net income (loss) attributable to the limited partners by the weighted average number of common units outstanding during the period. Diluted income (loss) per unit reflects potential dilution and is computed by dividing net income (loss) attributable to the limited partners by the weighted average number of common units outstanding during the period increased by the number of additional common units that would have been outstanding if the potentially dilutive units had been issued.

Basic income (loss) per unit and diluted income (loss) per unit are the same for the years ended December 31, 2001, 2000, and 1999, as the number of potentially dilutive units were so small as not to cause the diluted earnings per unit to be different from the basic earnings per unit. We include the outstanding publicly held preference units in 1999 and 2000 in the basic and diluted net income (loss) per unit calculation as if the publicly held preference units had been converted into common units. As of October 2000, all publicly held preference units have been converted into common units or redeemed.

Comprehensive Income

Our comprehensive income is determined based on net income (loss), adjusted for changes in accumulated other comprehensive income (loss) from our cash flow hedging activities at EPIA.

Unit-Based Compensation

We apply the provisions of Accounting Principles Board Opinion (APB) No. 25 and related interpretations in accounting for unit options issued to former employees of our general partner and our board of directors. Accordingly, compensation expense is not recognized for these unit options unless the options were granted at an exercise price lower than the market price of common units on the grant date. We use fixed plan accounting for our restricted unit grants. We apply the provisions of SFAS No. 123, Accounting for Stock-Based Compensation, for unit options issued to employees of affiliates of our general partner. For these options, we amortize the fair value of these options as of the grant date over the vesting period of the grant.

Cumulative Effect of Accounting Change

In the fourth quarter of 1999, we changed our method of allocating net income to our partners' capital accounts from a method where we allocated income based on percentage ownership and proportionate share of cash distributions, to a method where income is allocated to the partners based upon the change from period to period in their respective claims on our book value capital. We believe that the new income allocation method is preferable because it more accurately reflects the income allocation provisions called for under the partnership agreement and the resulting partners' capital accounts are more reflective of a partner's claim on our book value capital at each period end. This change in accounting had no impact on our consolidated net income or our consolidated total partners' capital for any period presented. This change did not impact the declaration of distributions or the individual partner tax basis.

The impact of this change in accounting has been recorded as a cumulative effect adjustment in our income allocation for the year ended December 31, 1999. The effect of adopting this change in accounting, excluding the cumulative adjustment, was to reduce basic and diluted net income per limited partner unit by $0.33 for the year ended December 31, 1999.

Business Combinations

In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, Business Combinations. This statement requires that all transactions that fit the definition of a business combination be accounted for using the purchase method and prohibits the use of the pooling of interests method for all business combinations initiated after June 30, 2001. This statement also established specific criteria for the recognition of intangible assets separately from goodwill and requires unallocated negative goodwill to be written off immediately as an extraordinary item. The accounting for any business combination we undertake in the future will be impacted by this standard. We adopted the provisions of this standard and applied them to each of our acquisitions initiated after June 30, 2001. For transactions initiated prior to June 30, 2001, we applied the provisions of APB Opinion No. 16. Our adoption of SFAS No. 141 did not have a material effect on our financial position or results of operations.

Goodwill and Other Intangible Assets

In July 2001, the FASB issued SFAS No. 142, Goodwill and Other Intangible Assets. This statement requires that goodwill no longer be amortized but intermittently tested for impairment at least on an annual basis. Other intangible assets are to be amortized over their useful life and reviewed for impairment in accordance with the provisions of SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of. An intangible asset with an indefinite useful life can no longer be amortized until its useful life becomes determinable. This statement has various effective dates, the most significant of which is January 1, 2002. Upon adoption of this Statement on January 1, 2002, we will no longer recognize annual amortization expense of approximately $120 thousand on goodwill and indefinite-lived intangible assets. We do not expect the impact of adopting this pronouncement to have a material effect on our financial statements; however, our impairment tests are not yet complete.

Accounting for Asset Retirement Obligations

In July 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. This statement requires companies to record a liability relating to the retirement and removal of assets used in their business. The liability is discounted to its present value, and the related asset value is increased by the amount of the resulting liability. Over the life of the asset, the liability will be accreted to its future value and eventually extinguished when the asset is taken out of service. The provisions of this statement are effective for fiscal years beginning after June 15, 2002. We are currently evaluating the effects of this pronouncement.

Accounting for the Impairment or Disposal of Long-Lived Assets

In October 2001, the FASB issued SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. This statement requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less cost to sell. The standard also expanded the scope of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of this statement are effective for fiscal years beginning after December 15, 2001.

The provisions of this pronouncement will impact any asset dispositions we make after January 1, 2002, including our pending sale of the Prince TLP and the 9 percent overriding royalty interest in the Prince Field.

2. ACQUISITIONS AND DISPOSITIONS

Midstream Businesses

In February 2002, we agreed to acquire midstream businesses from El Paso Corporation. The primary businesses to be acquired include:

- the 9,400 mile EPGT Texas intrastate pipeline, with a capacity of approximately 5 Bcf/d and average throughput of 3,500 MDth/d during 2001;

- 1,300 miles of gathering systems in the Permian Basin gathering system with a capacity of 465 MMcf/d and average throughput of 341 MDth/d during 2001; and

- a 42.3 percent non-operating interest in the Indian Basin gas processing and treating plant and associated gathering lines.

Total consideration for these transactions is approximately $750 million and will include the following consideration to subsidiaries of El Paso Corporation:

- the sale of our Prince TLP and the 9 percent overriding royalty interest in the Prince Field for approximately $190 million after our repayment of the related limited recourse debt of $95 million;

- the issuance of $6 million in common units; and

- a cash payment of $554 million.

These amounts will be adjusted at closing for the value of working capital acquired or sold. We will retain third-party marketing rights for remaining platform capacity and an option to repurchase the TLP at the end of the Prince Field reserve life. We expect to finance the purchase of these businesses through debt and equity financing in accordance with our strategy to maintain a strong balance sheet. The transaction is expected to close in the first quarter of 2002 subject to receiving regulatory approvals and arranging satisfactory financing.

NGL Storage Facilities

In December 2001, we acquired Anse La Butte, a 3.2 million barrel NGL multi-product storage facility near Breaux Bridge, Louisiana and have included it in our operating results from the date acquired. We also acquired in January 2002, a 3.3 million barrel propane storage business and complete leaching operation located in Hattiesburg, Mississippi from Suburban Propane Partners, L.P. The purchase price for these two assets was approximately $10 million.

Deepwater Holdings L.L.C. and Chaco Transaction

In October 2001, we acquired the remaining 50 percent interest that we did not already own in Deepwater Holdings for approximately $81 million, consisting of $26 million cash and $55 million of assumed indebtedness and at the acquisition date also repaid all of Deepwater Holdings $110 million of indebtedness. HIOS and East Breaks became indirect wholly-owned assets through this transaction. In a separate transaction, we also acquired the Chaco cryogenic natural gas processing plant for $198.5 million. The total purchase price was composed of a payment of $77 million to acquire the plant from the bank group that provided the financing for the construction of the facility and a payment of $121.5 million to El Paso Field Services in connection with the execution of a 20-year fee-based processing agreement relating to the processing capacity of the Chaco plant and dedication of natural gas gathered by El Paso Field Services to the Chaco plant. Under the terms of the processing agreement, we receive a fixed fee for each dekatherm of natural gas that we process at the Chaco plant, and we bear all costs associated with the plant's ownership and operations. El Paso Field Services personnel will continue to operate the plant. In accordance with the original construction financing agreements, the Chaco plant is under an operating lease to El Paso Field Services. El Paso Field Services has the right to repurchase the Chaco Plant at the end of the lease term in October 2002 for approximately $77 million. If El Paso Field Services does not exercise this repurchase right, it must pay us a forfeiture penalty. We funded both of these transactions by borrowing from our revolving credit facility. We accounted for these transactions as purchases and have assigned the purchase price to the net assets acquired based upon the estimated fair value of the net assets as of the acquisition date. The values assigned are preliminary and may be revised based on additional information. The operating results associated with Deepwater Holdings are included in earnings from unconsolidated affiliates for the periods prior to October 2001. We have included the operating results of Deepwater Holdings and the Chaco plant in our consolidated financial statements from the acquisition date.

Since the Chaco transaction was an asset acquisition, we have assigned the total purchase price to property, plant and equipment and investment in processing agreement. Since the Deepwater Holdings transaction was an acquisition of additional interests in a business, we are providing summary information related to the acquisition of Deepwater Holdings in the following table (in thousands):

Fair value of assets acquired	$ 81,331
Cash acquired	5,386
Fair value of liabilities assumed	(60,917)
Net cash paid	$ 25,800

EPN Texas

In February 2001, we acquired EPN Texas from a subsidiary of El Paso Corporation for $133 million. We funded the acquisition of these assets by borrowing from our revolving credit facility. These assets include more than 600 miles of NGL gathering and transportation pipelines. The NGL pipeline system gathers and transports unfractionated and fractionated products. We also acquired three fractionation plants with a capacity of approximately 96 MBbls/d. These plants fractionate NGLs into ethane, propane and butane products which are used by refineries and petrochemical plants along the Texas Gulf Coast. We accounted for the acquisition as a purchase and assigned the purchase price to the assets acquired based upon the estimated fair value of the assets as of the acquisition date. We have included the operating results of EPN Texas in our consolidated financial statements from the acquisition date.

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the twelve months ended December 31, 2001 and 2000, as if we acquired EPN Texas, the Chaco plant and the remaining 50 percent interest in Deepwater Holdings on January 1, 2000:

	2001	2000
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)	
Operating revenues	$269,681	$222,080
Operating income	$101,406	$ 96,197
Net income allocated to limited partners	$ 39,157	$ 15,790
Basic and diluted net income per unit	$ 1.14	$ 0.54

Gulf of Mexico Assets

In accordance with an FTC order related to El Paso Corporation's merger with The Coastal Corporation, we, along with Deepwater Holdings, agreed to sell several of our offshore Gulf of Mexico assets to third parties in January 2001. Total consideration received for these assets was approximately $163 million consisting of approximately $109 million for the assets we sold and approximately $54 million for the assets Deepwater Holdings sold. The offshore assets sold include interests in Stingray, UTOS, Nautilus, Manta Ray Offshore, Nemo, Tarpon, and the Green Canyon pipeline assets, as well as interests in two offshore platforms and one dehydration facility. We recognized net losses from the asset sales of approximately $12 million, and Deepwater Holdings recognized losses of approximately $21 million. Our share of Deepwater Holdings losses was approximately $14 million, which has been reflected in earnings from unconsolidated affiliates in the accompanying statements of income.

As additional consideration for the above transactions, El Paso Corporation will make payments to us totaling $29 million. These payments will be made in quarterly installments of $2.25 million for the next three years and $2 million in the first quarter of 2004. From this additional consideration, we realized income of approximately $25 million in the first quarter of 2001, which has been reflected in other income in the accompanying statements of income.

Crystal Gas Storage

In August 2000, we acquired the salt dome natural gas storage businesses of Crystal Gas Storage, Inc., a subsidiary of El Paso Corporation, in exchange for $170 million of Series B 10% Cumulative Redeemable Preference Units. We accounted for the acquisition as a purchase and assigned the purchase price to the assets and liabilities acquired based upon the estimated fair value of those assets and liabilities as of the acquisition date. We have included the operating results of Crystal Gas Storage, Inc. in our consolidated financial statements from the acquisition date. The following is summary information related to the acquisition (in thousands):

Fair value of assets acquired	$170,573
Fair value of liabilities assumed	(573)
Preference units issued	$170,000

El Paso Intrastate-Alabama Pipeline System

In March 2000, we acquired EPIA from a subsidiary of El Paso Corporation for $26.5 million in cash. We accounted for the acquisition as a purchase and assigned the purchase price to the assets and liabilities acquired based upon the estimated fair value of those assets and liabilities as of the acquisition date. We have included the operating results of EPIA in our consolidated financial statements from the acquisition date. The following is summary information related to the acquisition (in thousands):

Fair value of assets acquired	$28,261
Fair value of liabilities assumed	(1,785)
Net cash paid	$26,476

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the years ended December 31, 2000 and 1999, assuming we acquired EPIA and the Crystal natural gas storage businesses on January 1, 1999:

	2000	1999
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)	
Operating revenues	$131,426	$105,930
Operating income	$ 45,171	$ 12,484
Net income allocated to limited partners before accounting change	$ 1,887	$ 5,406
Basic and diluted net income per unit before cumulative effect of accounting change	$ 0.06	$ 0.21

Deepwater Holdings

In June 1999, we acquired additional interests in the HIOS, UTOS and East Breaks systems through our acquisition of Natoco, Inc. and Naloco, Inc. for $51 million. As part of the transaction, we also assumed operations of the Stingray system, the Stingray Offshore separation facility and the West Cameron dehydration facility in November 1999. The purchase price exceeded the book value of net assets acquired by approximately $48 million. This excess cost is being amortized on a straight-line basis over the estimated lives of the acquired assets, which approximates 30 years.

In September 1999, we formed Deepwater Holdings with ANR to reorganize our interests in various joint ventures. In the transaction, both parties contributed their respective interests in various pipeline systems and facilities to Deepwater Holdings. Following this reorganization, Deepwater Holdings owns 100 percent of the East Breaks, HIOS, UTOS, and Stingray systems, along with the West Cameron dehydration facility. In exchange for our contribution, we received a 59.66 percent interest in Deepwater Holdings. We subsequently sold a 9.66 percent members' interest in Deepwater Holdings to ANR for $26.1 million to effect a 50/50 ownership position. We realized a $10.1 million gain associated with the sale. In conjunction with the transaction, we became the full operator of the UTOS, HIOS, and East Breaks systems on June 1, 2000.

In connection with its formation, Deepwater Holdings established a $175 million credit facility to:

- retire existing debt of Stingray and Western Gulf, the parent company of East Breaks and HIOS;

- fund a one-time distribution of $20 million to each of the equity partners;

- provide funds for the remaining construction costs of the East Breaks system and any future system expansions; and

- provide for other working capital needs of Deepwater Holdings.

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the year ended December 31, 1999, assuming the transactions relating to Deepwater Holdings discussed above had occurred on January 1, 1999:

	1999
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)
Operating revenues	$93,071
Operating income	$39,841
Net loss allocated to limited partners before accounting change	$(7,364)
Basic and diluted net loss per unit before cumulative effect of accounting change	$ (0.28)

As a result of El Paso Corporation's January 2001 merger with The Coastal

Corporation, ANR is now our affiliate and Deepwater Holdings no longer has interests in Stingray, UTOS or the West Cameron dehydration facility. As discussed earlier, we acquired the remaining 50 percent interest in Deepwater Holdings that we did not already own in October 2001.

Viosca Knoll

In June 1999, we acquired an additional 49 percent interest in Viosca Knoll from El Paso Field Services. In the transaction, El Paso Field Services contributed $33.4 million to Viosca Knoll and then sold a 49 percent interest to us in exchange for $19.9 million and 2,661,870 common units. We paid closing costs of $0.9 million in connection with the acquisition and our general partner contributed $0.6 million to us in order to maintain its one percent capital account balance. As a result of the acquisition, we began consolidating the operating results of Viosca Knoll in June 1999.

The acquisition was accounted for as a purchase and the purchase price was assigned to the assets and liabilities acquired based upon their estimated fair value as of the acquisition date. The following is summary information related to the acquisition (in thousands):

Fair value of assets acquired	$ 83,105
Cash acquired	434
Fair value of liabilities assumed	(2,962)
Total purchase price	80,577
Issuance of common units	(59,792)
Closing costs paid	(900)
Net cash paid	$ 19,885

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the year ended December 31, 1999, assuming the Viosca Knoll acquisition had occurred on January 1, 1999:

	1999
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)
Operating revenues	$104,951
Operating income	$ 48,710
Net income allocated to limited partners before accounting change	$ 8,675
Basic and diluted net income per unit before cumulative effect of accounting change	$ 0.32

In September 2000, we purchased the remaining one percent of Viosca Knoll from El Paso Field Services for approximately $2.0 million bringing our total investment in Viosca Knoll to 100 percent.

3. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. As of December 31, 2001, the carrying amount of our equity investment exceeded the underlying equity in net assets by approximately $3.0 million. This difference is being amortized on a straight-line basis over the estimated life of the underlying net assets of our investment. With our adoption of SFAS No. 142 on January 1, 2002, we will no longer amortize this excess amount but will intermittently test (no less than annually) these amounts for impairment under the provisions of SFAS No. 142. Summarized financial information for these investments is as follows:

	AS OF OR FOR THE YEAR ENDED DECEMBER 31, 2001				
	DEEPWATER HOLDINGS(A)	POSEIDON	DIVESTED INVESTMENTS(B)	OTHER	TOTAL
	(IN THOUSANDS)				
END OF PERIOD OWNERSHIP INTEREST..........	100%	36%	--	50%	
OPERATING RESULTS DATA:					
Operating revenues......................	$ 40,933	$ 71,516	$1,982	$145	
Other income (loss).....................	--	394	(85)		
Operating expenses......................	(16,740)	(2,701)	(590)	(73)	
Depreciation............................	(8,899)	(10,552)	(953)		
Other (expenses) income.................	(5,868)	(7,668)	222	(22)	
Loss on sale of assets..................	(21,453)	--	--		
Net income (loss).......................	$(12,027)	$ 50,989	$ 576	$ 50	
OUR SHARE:					
Allocated income (loss) (c).............	$ (9,925)	$ 18,356	$ 148	$ 25	
Adjustments(d)..........................	--	(146)	(9)	--	
Earnings (loss) from unconsolidated affiliates..........................	$ (9,925)	$ 18,210	$ 139	$ 25	$ 8,449
Allocated distributions.................	$ 12,850	$ 22,212	$ --	$ --	$35,062
FINANCIAL POSITION DATA:					
Current assets..........................		$ 91,367		$177	
Noncurrent assets.......................		226,570		--	
Current liabilities.....................		80,365		33	
Long-term debt..........................		150,000		--	

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(a) In January 2001, Deepwater Holdings sold its Stingray and West Cameron subsidiaries. Deepwater Holdings sold its interest in its UTOS subsidiary in April 2001. In October 2001, we acquired the remaining 50 percent of Deepwater Holdings and as a result of this transaction, on a going forward basis Deepwater Holdings is consolidated in our financial statements. The information presented for Deepwater Holdings as an equity investment is through October 18, 2001.

(b) Divested Investments contains Manta Ray Offshore Gathering Company, L.L.C. and Nautilus Pipeline Company L.L.C. In January 2001, we sold our 25.67 percent interest in Manta Ray Offshore and our 25.67 percent interest in Nautilus.

(c) The income (loss) from Deepwater Holdings is not allocated proportionately with our ownership percentage because the capital contributed by us was a larger amount of the total capital at the time of formation. Therefore, we were allocated a larger amount of amortization of Deepwater Holdings' excess purchase price of its investments. Also, we were allocated a larger portion of Deepwater Holdings' $21 million loss incurred in 2001 due to the sale of Stingray, UTOS, and the West Cameron dehydration facility. Our total share of the losses relating to these sales was approximately $14 million.

(d) We recorded adjustments primarily for differences from estimated year end 2000 earnings reported in our 2000 Annual Report on Form 10-K and actual earnings reported in the 2000 audited annual reports of our unconsolidated affiliates.

AS OF OR FOR THE YEAR ENDED DECEMBER 31, 2000	DEEPWATER HOLDINGS	POSEIDON	DIVESTED INVESTMENTS(A)	OTHER	TOTAL
	(IN THOUSANDS)				
END OF PERIOD OWNERSHIP INTEREST	50%	36%	25.67%	50%	
OPERATING RESULTS DATA:					
Operating revenues	$ 67,122	$ 65,158	$ 26,478	$110	
Other income	532	639	2,301	--	
Operating expenses	(25,279)	(24,398)	(5,205)	(51)	
Depreciation	(18,138)	(10,754)	(10,363)	--	
Other expenses	(10,711)	(11,683)	(432)	(19)	
Net income	$ 13,526	$ 18,962	$ 12,779	$ 40	
OUR SHARE:					
Allocated income	$ 6,763	$ 6,826	$ 3,281	$ 20	
Adjustments(b)	507	5,892	(358)	--	
Earnings from unconsolidated affiliates	$ 7,270	$ 12,718	$ 2,923	$ 20	$22,931
Allocated distributions	$ 13,550	$ 13,532	$ 6,878	$ --	$33,960
FINANCIAL POSITION DATA:					
Current assets	$ 46,128	$125,325	$ 4,375	$111	
Noncurrent assets	237,416	239,030	247,554	--	
Current liabilities	39,962	264,776	1,423	27	
Long-term debt	157,000	--	--	--	
Other noncurrent liabilities	9,517	1,297	--	--	

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(a) Divested Investments contains Manta Ray Offshore Gathering Company, L.L.C. and Nautilus Pipeline Company L.L.C. In January 2001, we sold our 25.67 percent interest in Manta Ray Offshore and our 25.67 percent interest in Nautilus.

(b) We recorded adjustments primarily for differences from estimated year end 1999 earnings reported in our 1999 Annual Report on Form 10-K and actual earnings reported in the 1999 audited annual reports of our unconsolidated affiliates, and for purchase price adjustments under APB Opinion No. 16, "Business Combinations." The adjustment for Poseidon primarily represents the receipt or expected receipt of insurance proceeds to offset our share of the repair costs related to the January 2000 pipeline rupture.

AS OF OR FOR THE YEAR ENDED DECEMBER 31, 1999	DEEPWATER HOLDINGS(A)	POSEIDON	DIVESTED INVESTMENTS(B)	VIOSCA KNOLL(C)	OTHER	TOTAL
	(IN THOUSANDS)					
END OF PERIOD OWNERSHIP INTEREST	50%	36%	25.67%	99%	50%	
OPERATING RESULTS DATA:						
Operating revenue	$ 59,965	$76,160	$ 26,620	$12,338	$ 35	
Other income	2,203	403	2,328	31	--	
Operating expenses	(31,081)	(8,774)	(5,164)	(925)	(18)	
Depreciation	(13,629)	(6,172)	(11,195)	(1,752)	--	
Other expenses	(2,918)	(9,133)	(350)	(1,973)	--	
Net income	$ 14,540	$52,484	$ 12,239	$ 7,719	$ 17	
OUR SHARE:						
Allocated income	$ 6,591	$18,894	$ 3,142	$ 3,860	$ 8	
Adjustments(d)	1,173	(7)	(839)	--	(8)	
Earnings from unconsolidated affiliates	$ 7,764	$18,887	$ 2,303	$ 3,860	$ --	$32,814
Allocated distributions	$ 15,601	$18,191	$ 5,906	$ 6,350	$132	$46,180
FINANCIAL POSITION DATA:						
Current assets	$ 34,334	$171,720	$ 7,934		$376	
Noncurrent assets	208,939	243,971	245,164		--	
Current liabilities	32,727	159,359	5,157		44	
Long-term debt	122,000	150,000	--		--	
Other noncurrent liabilities	41	322	--		--	

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(a) Deepwater Holdings was formed in September 1999 and owned 100 percent of Stingray, HIOS, UTOS, and the West Cameron dehydration facility. The operating results are the pro forma results of Deepwater Holding and each of its subsidiaries, Stingray, HIOS, UTOS and the West Cameron dehydration facility, as if formation of Deepwater Holdings and its acquisitions of Stingray, HIOS, UTOS and the West Cameron dehydration facility had occurred January 1, 1999.
(b) Divested Investments contains Manta Ray Offshore Gathering Company, L.L.C. and Nautilus Pipeline Company L.L.C. In January 2001, we sold our 25.67 percent interest in Manta Ray Offshore and our 25.67 percent interest in Nautilus.
(c) The information presented for Viosca Knoll as an equity investment is through May 31, 1999. On June 1, 1999, we began consolidating the results of Viosca Knoll as a result of acquiring an additional 49 percent interest in the system.
(d) We recorded adjustments primarily for purchase price adjustments in accordance with APB Opinion No. 16, except for Stingray which resulted from changes in estimates of reserves for uncollectable revenues.

4. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

DECEMBER 31,	2001	2000
	(IN THOUSANDS)	
Property, plant and equipment, at cost		
Pipelines	$ 856,335	$239,920
Platforms and facilities	281,600	127,639
Processing plant	138,450	--
Oil and natural gas properties	159,375	156,320
Storage facilities	156,800	147,294
Construction work-in-progress	99,335	127,811
	1,691,895	798,984
Less accumulated depreciation and depletion	588,468	179,746
Total property, plant and equipment, net	$1,103,427	$619,238

Due to the sale of our interest in the Manta Ray Offshore system in January 2001, we lost a primary connecting point to our Manta Ray pipeline. As a result, we abandoned the Manta Ray pipeline and recorded an impairment of approximately $3.9 million in the first quarter of 2001 which is reflected in the Natural Gas Gathering and Transportation segment.

5. INVESTMENT IN PROCESSING AGREEMENT

As part of our October 2001 Chaco transaction, we paid $121.5 million to El Paso Field Services for a 20-year fee-based processing agreement. This amount is being amortized on a straight-line basis over the life of the agreement. Under the processing agreement, all previously uncommitted volumes on El Paso Field Services' San Juan Gathering System are dedicated to the Chaco plant. As part of the agreement, natural gas delivered to the Chaco plant by El Paso Field Services will have a processing priority over other natural gas.

6. FINANCING TRANSACTIONS

In February 2002, our universal shelf registration to offer up to $1 billion of capital securities representing limited partnership interests and debt securities and related guarantees, as filed with the SEC, became effective.

Senior Subordinated Notes

In May 2001, we issued $250 million in aggregate principal amount of 8 1/2% Senior Subordinated Notes. These notes bear interest at a rate of 8 1/2% per year, payable semi-annually in June and December, and mature in June 2011. Proceeds of approximately $243 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility.

In May 1999, we issued $175 million in aggregate principal amount of 10 3/8% Senior Subordinated Notes. These notes bear interest at a rate of 10 3/8% per annum, payable semi-annually in June and December, and mature in June 2009. Proceeds of approximately $169 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility.

Our subsidiaries, except Argo and Argo I L.L.C., have guaranteed our obligations under both issuances of senior subordinated notes. In addition, we could be required to repurchase the senior subordinated notes if certain circumstances relating to change of control or asset dispositions exist. The terms of the senior subordinated notes include, among other things, financial tests and covenants, all of which we currently meet.

Revolving Credit Facility

In May 2001, we amended and restated our revolving credit facility with a syndicate of commercial banks to provide up to $600 million of available credit subject to compliance with financial ratios as specified in the agreement. As of December 31, 2001, we had $300 million outstanding under this facility with the full unused amount available. The average variable interest rate on the debt outstanding was 3.9% and 9.1% at December 31, 2001 and 2000. We pay a variable commitment fee on the unused portion of the credit facility. Our credit facility matures in May 2004; is guaranteed by us and all of our subsidiaries except for our Argo and Argo I subsidiaries; and is collateralized by our management agreement, substantially all of our assets (excluding our Argo and Argo I subsidiaries), and our general partner's one percent general partner interest in us. We may borrow money under this facility for capital expenditures, investment and working capital purposes as well as to make distributions under certain circumstances.

Limited Recourse Term Loan

In August 2000, Argo, L.L.C., one of our unrestricted subsidiaries obtained a $95 million limited recourse project finance loan from a group of commercial lenders to finance a substantial portion of the total cost of the Prince TLP, pipelines and other facilities. The Prince TLP was installed in the Prince Field in July 2001, and we placed it into service in September 2001. In accordance with its terms, the project finance loan was converted into a term loan in December 2001 and will mature in December 2006. The $95 million term loan requires us to pay interest and principal in twenty equal quarterly installments. The first principal payment is due at the end of the first quarter of 2002. The term loan is collateralized by substantially all of Argo's assets. The term loan agreement restricts Argo's ability to pay distributions to us. If Argo defaults on its payment obligations, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Argo up to $30 million. As of December 31, 2001, Argo had $95 million outstanding under this limited recourse term loan and had not paid us, or any of our subsidiaries, any distributions. The average variable interest rate on the debt outstanding for 2001 and 2000 was 4.1% and 8.4% at December 31, 2001 and 2000.

Other Credit Facilities

Poseidon Oil Pipeline Company, L.L.C. is party to a credit agreement under which it has outstanding obligations that may restrict its ability to pay distributions to its owners. Deepwater Holdings, L.L.C. was a party to a credit agreement but, in conjunction with our purchase in October 2001 of the 50 percent interest that we did not already own, the $110 million balance outstanding at the acquisition date was repaid and the credit facility was terminated.

In April 2001, Poseidon amended and restated its credit facility to provide up to $185 million of the construction and expansion of the Poseidon system and for other working capital changes. Poseidon's ability to borrow money under this facility is subject to certain customary terms and conditions, including borrowing base limitations. The facility is collateralized by a substantial portion of Poseidon's assets and matures in April 2004. As of December 31, 2001, Poseidon had $150 million outstanding under its facility with the full unused balance available. The average variable floating interest rate on the debt outstanding at December 31, 2001 and 2000 was 3.8% and 7.9%. In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the interest rate at 3.49% through January 2004 on $75 million of the $150 million outstanding on their credit facility.

Interest Expense

We recognized the interest cost incurred in connection with our financing transactions as follows for each of the years ended:

	2001	2000	1999
	(IN MILLIONS)		
Interest expense incurred	$54.9	$51.1	$37.1
Interest capitalized	11.8	4.0	1.8
Net interest expense	$43.1	$47.1	$35.3

7. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The carrying amounts and estimated fair values of our financial instruments at December 31 are as follows:

	2001		2000	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	(IN MILLIONS)			
Liabilities:				
Revolving credit facility	$300	$300	$318	$318
Limited recourse term loan	95	95	45	45
10 3/8% Senior Subordinated Notes	175	186	175	185
8 1/2% Senior Subordinated Notes	250	253	N/A	N/A
Non-trading derivative instruments				
Commodity swap and forward contracts	$ 1	$ 1	$ --	$ --

The notional amounts and terms of contracts held for purposes other than trading were as follows at December 31:

	2001			2000		
	NOTIONAL VOLUME		MAXIMUM TERM IN YEARS	NOTIONAL VOLUME		MAXIMUM TERM IN YEARS
	BUY	SELL		BUY	SELL	
Commodity						
Natural Gas (MDth)	765	--	<1	--	--	N/A

As of December 31, 2001, and 2000, our carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because of the market based nature of the debt's interest rates. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues.

8. PARTNERS' CAPITAL

General

As of December 31, 2001, we had 39,738,974 common units outstanding. Common units totaling 29,308,140 are owned by the public, representing a 74 percent limited partner interest in us. As of December 31, 2001, El Paso Corporation, through its subsidiaries, owned 10,430,834 common units, or

26 percent of our outstanding common units, 125,392 Series B preference units (with a liquidation value of $143 million) and our one percent general partner interest.

Offering of Common Units

In October 2001, we completed a offering of 5,627,070 common units, which included a public offering of 4,150,000 common units and a private offering, at the same unit price, of 1,477,070 common units to our general partner. We used the net cash proceeds of approximately $212 million to redeem 44,608 of our Series B preference units for their liquidation value of $50 million and to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed $2.1 million in cash to us in order to satisfy its one percent contribution requirement.

In March 2001, we completed a public offering of 2,250,000 common units. We used the net cash proceeds of $66.6 million from the offering to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed $0.7 million to us in order to satisfy its one percent capital contribution requirement.

In July 2000, we completed a public offering of 4,600,000 common units. We used the net cash proceeds of $101 million to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed $1.1 million to us in order to satisfy its one percent capital contribution requirement.

Conversion and Redemption of Preference Units

In May 1998, 1999 and 2000, we notified the holders of our publicly-held preference units of their opportunity to convert their preference units into an equal number of common units. Total preference units of 211,249 were converted to common units after the 90-day conversion period in 2000 and 78,450 preference units remained. In October 2000, we redeemed the remainder of these preference units for approximately $0.8 million representing a cash price of $10.25 per unit. For the converted units, we reallocated the partners' capital accounts in the conversion period to reflect these conversions of preference units into common units.

Series B Preference Units

In August 2000, we issued $170 million of Series B preference units to acquire the natural gas storage businesses of Crystal Gas Storage, Inc. These newly issued preference units are non-voting and have rights to income allocations on a cumulative basis, compounded semi-annually at an annual rate of 10%. We are not obligated to pay cash distributions on these units until 2010. After September 2010, the rate will increase to 12% and preference income allocation after 2010 will be required to be paid on a current basis; accordingly, after September 2010, we will not be able to make distributions on our common units unless all unpaid accruals occurring after September 2010 on our then-outstanding Series B preference units have been paid. These preference units contain no mandatory redemption obligation, but may be redeemed at our option at any time. If our capital was ever liquidated, then these Series B preference units would have priority after our general partner, but before our outstanding common unitholders. In October 2001, we redeemed 44,608 of the Series B preference units for $50 million liquidation value including accrued distributions of approximately $5.4 million, bringing the total number of units outstanding to 125,392. As of December 31, 2001, the liquidation value of the outstanding Series B preference units was approximately $143 million.

Cash Distributions

We make quarterly distributions of 100 percent of our available cash, as defined in the partnership agreement, to our unitholders and to our general partner. Available cash generally consists of all cash receipts plus reductions in reserves less all cash disbursements and net additions to reserves. Our general partner has broad discretion to establish cash reserves for any proper partnership purpose. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt, or, as necessary, reserves to comply with the terms of our agreements or obligations. Beginning in the fourth quarter of 2010, any unpaid accruals on our Series B preference units occurring after September 2010 will be currently payable and must be completely paid, prior to any distributions on our common units.

Cash distributions on common units and to our general partner are discretionary in nature and are not entitled to arrearages of minimum quarterly distributions. The following table reflects our per unit cash distributions to our common unitholders and the total incentive distributions paid to our general partner during the year ended December 31, 2001:

MONTH PAID	COMMON UNIT (PER UNIT)	GENERAL PARTNER (IN MILLIONS)
February	$0.5500	$4.6
May	$0.5750	$5.8
August	$0.5750	$5.8
November	$0.6125	$8.1

In January 2002, we declared a cash distribution of $0.625 per common unit, or $33.7 million in the aggregate, which we paid on February 15, 2002.

For the year ended December 31, 2001, 2000 and 1999, we paid our general partner incentive distributions totaling $24.3 million, $15.5 million, and $12.1 million, respectively, and paid an incentive distribution of $8.6 million in February 2002.

Option Plans

In August 1998, we adopted the 1998 Omnibus Compensation Plan (Omnibus Plan) to provide our general partner with the ability to issue unit options to attract and retain the services of knowledgeable officers and key management personnel. Unit options to purchase a maximum of 3 million common units may be issued pursuant to the Omnibus Plan. Unit options granted to date pursuant to the Omnibus Plan are not immediately exercisable. For unit options granted in 2001, one-half of the unit options are considered vested and exercisable one year after the date of grant and the remaining one-half of the unit options are considered vested and exercisable one year after the first anniversary of the date of grant. These unit options expire ten years from such grant date, but shall be subject to earlier termination under certain circumstances.

In August 1998, we adopted the 1998 Unit Option Plan for Non-Employee Directors (Director Plan) to provide our general partner with the ability to issue unit options to attract and retain the services of knowledgeable directors. Unit options and restricted units to purchase a maximum of 100,000 of our common units may be issued pursuant to the Director Plan. Under the Director Plan, each non-employee director receives a grant of 2,500 unit options upon initial election to the Board of Directors and an annual unit option grant of 2,000 unit options and, beginning in 2001, an annual restricted unit grant equal to the director's annual retainer (including Chairman's retainers, if applicable) divided by the fair market value of the common units on the grant date upon each re-election to the Board of Directors. Each unit option that is granted will vest immediately at the date of grant and will expire ten years from such date, but will be subject to earlier termination in the event that such non-employee director ceases to be a director of our general partner for any reason, in which case the unit options expire 36 months after such date except in the case of death, in which case the unit options expire 12 months after such date. Each director receiving a grant of restricted units is recorded as a unitholder and has all the rights of a unitholder with respect to such units, including the right to distributions on those units. The restricted units are nontransferable during the director's service on the Board of Directors. The restrictions on the restricted units will end and the director will receive one common unit for each restricted unit granted upon the director's termination. The Director Plan is administered by a management committee consisting of the Chairman of the Board of directors of the general partner and such other senior officers of our general partner or its affiliates as the Chairman of the Board may designate. During 2001, we issued 4,090 shares of restricted units with a grant price of $33.00 per unit. The value of these units is determined based on the fair market value on the grant date.

The following table summarizes activity under the Omnibus Plan and Director Plan as of and for the years ended December 31, 2001, 2000 and 1999.

	2001		2000		1999	
	# UNITS OF UNDERLYING OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE	# UNITS OF UNDERLYING OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE	# UNITS OF UNDERLYING OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at beginning of year	925,500	$27.15	937,500	$27.16	933,000	$27.19
Granted	1,016,500	35.00	3,000	25.56	4,500	21.58
Exercised	307,500	27.17	--	--	--	--
Forfeited	--	--	7,500	27.19	--	--
Canceled	20,000	27.19	7,500	27.19	--	--
Outstanding at end of year	1,614,500	$32.09	925,500	$27.15	937,500	$27.16
Options exercisable at end of year	606,500	$27.22	925,500	$27.15	687,500	$27.15

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

ASSUMPTION	2001	2000	1999
Expected term in years	8	8	8
Expected volatility	27.50%	27.97%	28.70%
Expected dividends	9.55%	9.35%	9.20%
Risk-free interest rate	5.05%	5.35%	6.40%

The Black-Scholes weighted average fair value of options granted during 2001, 2000, and 1999 was $2.62, $2.63, and $3.14 per option, respectively.

Options outstanding as of December 31, 2001, are summarized below:

OPTIONS OUTSTANDING

OPTIONS EXERCISABLE

RANGE OF EXERCISE PRICES	NUMBER OUTSTANDING	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE	WEIGHTED AVERAGE EXERCISE PRICE
$19.86 to $27.80	598,000	6.6	$27.18	598,000	$27.18
$27.80 to $39.72	1,016,500	9.7	$34.97	8,500	$32.71
$19.86 to $39.72	1,614,500	8.6	$32.09	606,500	$27.22

If the compensation expense for our stock-based compensation plans, accounted for under APB 25, had been determined applying the provisions of SFAS No. 123, Accounting for Stock Based Compensation, using the Black-Scholes weighted average fair value of options granted, our net income (loss) allocated to the limited partners and net income (loss) per common unit for 2001, 2000, and 1999 would approximate the pro forma amounts below:

	DECEMBER 31, 2001		DECEMBER 31, 2000		DECEMBER 31, 1999	
	AS REPORTED	PRO FORMA	AS REPORTED	PRO FORMA	AS REPORTED	PRO FORMA
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)					
SFAS No. 123 charge, pretax.....	$ --	$ 311	$ --	$ 211	$ --	$ 890
Net income (loss) allocated to the limited partners..........	$13,260	$12,949	$ (749)	$ (960)	$(8,739)	$(9,629)
Basic and diluted income (loss) per unit......................	$ 0.38	$ 0.38	$(0.03)	$(0.03)	$ (0.34)	$ (0.37)

The effects of applying SFAS No. 123 in this pro forma disclosure are not indicative of future amounts.

9. RELATED PARTY TRANSACTIONS

The following table provides summary data for the income statement impacts of our transactions with related parties for the years ended December 31:

	2001	2000	1999
	(IN THOUSANDS)		
Revenues received from related parties:			
Gathering and transportation services....................	$12,674	$ 9,356	$ --
Liquid transportation and handling services..............	32,382	--	--
Platform services..	8,188	146	990
Storage services...	2,324	1,268	--
Oil and natural gas sales................................	672	15,722	29,778
	$56,240	$26,492	$30,768
Expenses paid to related parties:			
Purchased natural gas costs.............................	$34,646	$16,751	$ --
Operating expenses.......................................	34,499	22,817	13,494
	$69,145	$39,568	$13,494
Reimbursements received from related parties:			
Operating expenses.......................................	$11,499	$20,543	$ 2,377

At December 31, 2001 and 2000, our accounts receivable balances due from related parties were approximately $22.9 million and $1.6 million. At December 31, 2001 and 2000, our accounts payable balances due to related parties were approximately $9.9 million and $2.4 million.

In connection with the sale of our Gulf of Mexico assets, El Paso Corporation agreed to make quarterly payments to us of $2.25 million for three years beginning March 2001 and $2 million in the first quarter of 2004. At December 31, 2001, the present value of the amounts due from El Paso Corporation were classified as follows:

	(IN THOUSANDS)
Accounts receivable affiliate	$ 7,745
Other noncurrent assets	10,362

	$18,107
	=======

The following table provides summary data categorized by our related parties for the years ended December 31:

	2001	2000	1999
	-------	-------	-------
	(IN THOUSANDS)		
Revenues received from related parties:			
El Paso Corporation			
Merchant Energy North America Company	$ 9,865	$21,832	$29,778
El Paso Production Company	13,054	4,303	--
Southern Natural Gas Company	156	155	--
Tennessee Gas Pipeline Company	748	56	--
El Paso Field Services	32,382	--	--
Unconsolidated Subsidiaries			
Manta Ray Offshore(1)	35	146	--
Viosca Knoll Gathering Company(2)	--	--	990
	-------	-------	-------
	$56,240	$26,492	$30,768
	=======	=======	=======
Purchased natural gas costs paid to related parties:			
El Paso Corporation			
Merchant Energy North America Company	$28,047	$14,454	$ --
El Paso Production Company	6,412	2,160	--
Southern Natural Gas Company	187	137	--
	-------	-------	-------
	$34,646	$16,751	$ --
	=======	=======	=======
Operating expenses paid to related parties:			
El Paso Corporation			
El Paso Field Services	$33,965	$22,265	$11,726
Unconsolidated Subsidiaries			
Poseidon Oil Pipeline Company	534	552	944
Viosca Knoll Gathering Company(2)	--	--	824
	-------	-------	-------
	$34,499	$22,817	$13,494
	=======	=======	=======
Reimbursements received from related parties:			
Unconsolidated Subsidiaries			
Deepwater Holdings(3)	$ 9,399	$20,344	$ 1,820
Poseidon Oil Pipeline Company	2,100	--	--
Manta Ray Offshore(1)	--	199	515
Viosca Knoll Gathering Company(2)	--	--	42
	-------	-------	-------
	$11,499	$20,543	$ 2,377
	=======	=======	=======

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(1) We sold our interest in Manta Ray Offshore in January 2001 in connection with El Paso Corporation's merger with the Coastal Corporation.

(2) With our purchase of an additional 49 percent interest in Viosca Knoll Gathering Company in 1999, we began consolidating this company into our

financial statements.

(3) In January 2001, Deepwater Holdings sold its Stingray and West Cameron subsidiaries. In April 2001, Deepwater Holdings sold its UTOS subsidiary. In October 2001, we acquired the remaining 50 percent of Deepwater Holdings, and as a result of this transaction, on a going forward basis, Deepwater Holdings is consolidated in our financial statements and our agreement with Deepwater Holdings terminated.

Revenues received from related parties

EPN Texas. In connection with our acquisition of EPN Texas in February 2001, we entered into a 20-year fee-based transportation and fractionation agreement with El Paso Field Services. Pursuant to this agreement, we receive a fixed fee for each barrel of NGL transported and fractionated by our facilities. Approximately 25 percent of our per barrel fee is escalated annually for increases in inflation. For the year ended December 31, 2001, we received revenue of approximately $25.2 million related to this agreement.

Chaco processing plant. In connection with our Chaco transaction in October 2001, we entered into a 20-year fee-based processing agreement with El Paso Field Services. Pursuant to this agreement, we receive a fixed fee for each dekatherm of natural gas that we process at the Chaco plant. For the year ended December 31, 2001, we received revenue of $6.5 million related to this agreement. In accordance with the original construction financing agreements, the Chaco plant is under an operating lease to El Paso Field Services. For the year ended December 31, 2001, we received $0.6 million related to this lease.

Storage facilities. Merchant Energy North America Company and Tennessee Gas Pipeline Company use our storage caverns to store gas from time to time. For the year ended December 31, 2001, and the four months ended December 31, 2000 we received approximately $1.6 million and $1.2 million from Merchant Energy North America Company for natural gas storage fees. For the year ended December 31, 2001, and the four months ended December 31, 2000 we received approximately $0.7 million and $0.1 million from Tennessee Gas Pipeline Company.

Prince TLP. In September 2001, we placed our Prince TLP in service. We receive a monthly demand charge of approximately $1.9 million as well as processing fees from El Paso Production Company related to production on the Prince TLP. For the four months ended December 31, 2001, we received $8.2 million in platform revenue related to this agreement.

Production fields. In prior years we had agreed to sell substantially all of our oil and natural gas production to Merchant Energy North America Company on a month to month basis. The agreement provided fees equal to two percent of the sales value of crude oil and condensate and $0.015 per dekatherm of natural gas for marketing production. During the years ended December 31, 2000 and 1999, oil and natural gas sales related to this agreement totaled approximately $15.7 million and $29.8 million. Beginning in the fourth quarter of 2000, we began selling our oil and natural gas directly to third parties.

In October 1999, we farmed out our working interest in the Prince Field to El Paso Production Company. Under the terms of the farmout agreement, our net overriding royalty interest in the Prince Field increased to a weighted average of approximately nine percent. El Paso Production Company began production on the Prince Field in September 2001. For the year ended December 31, 2001, we recorded approximately $0.7 million in revenues related to our overriding royalty interest in the Prince Field.

EPIA. In March 2000, we acquired EPIA. Several El Paso Corporation subsidiaries buy and transport natural gas on our EPIA system. For the years ended December 31, 2001 and 2000, we received approximately $8.3 million and $4.9 million from Merchant Energy North America Company. For the years ended December 31, 2001 and 2000, we received approximately $4.2 million and $4.3 million from El Paso Production Company. For the years ended December 31, 2001 and 2000, we received approximately $0.2 million and $0.2 million from Southern Natural Gas Company.

Unconsolidated Subsidiaries. For the years ended December 31, 2001 and 2000, we received approximately $0.03 million and $0.1 million from Manta Ray Offshore Gathering as platform access and processing fees related to our South Timbalier 292 platform and our Ship Shoal 332 platform. For the five months ended May 31, 1999, we received from Viosca Knoll Gathering Company approximately $1.0 million for expenses and platform fees related to our Viosca Knoll 817 platform.

Expenses paid to related parties

Purchased natural gas costs. EPIA's purchases of natural gas include transactions with affiliates of our general partner. For the years ended December 31, 2001 and 2000, we had natural gas purchases of approximately $28.0 million and $14.4 million from Merchant Energy North America Company, $6.4 million and $2.2 million from El Paso Production Company and $0.2 million and $0.1 million from Southern Natural Gas Company.

Operating Expenses. Substantially all of the individuals who perform the day-to-day financial, administrative, accounting and operational functions for us, as well as those who are responsible for directing and controlling us, are currently employed by El Paso Corporation. Under a management agreement between a subsidiary of El Paso Corporation and our general partner, a management fee of $775,000 per month is charged to our general partner which is intended to approximate the amount of resources allocated by El Paso Corporation in providing various operational, financial, accounting and administrative services on behalf of our general partner and us. Under the terms of the partnership agreement, our general partner is entitled to reimbursement of all reasonable general and administrative expenses and other reasonable expenses incurred by our general partner and its affiliates for, or on our behalf, including, but not limited to, amounts payable by our general partner to El Paso Corporation under its management agreement. We are also charged for insurance and other costs paid directly by El Paso Field Services on our behalf. The management agreement expires on June 30, 2002, and may be terminated thereafter upon 90 days notice by either party.

As we became operator of each Deepwater Holdings subsidiary, acquired new operations or constructed new facilities, we entered into additional management and operating agreements with El Paso Field Services. All fees paid under these contracts approximate actual costs incurred.

The following table shows the amount El Paso Field Services charged us for each of our agreements for the year ended December 31:

	2001	2000	1999
	(IN THOUSANDS)		
Basic management fee	$ 9,300	$ 9,300	$ 9,300
Insurance and other costs	4,844	2,577	2,426
Deepwater Holdings operating fee	5,618	6,395	--
EPIA operating fee	3,036	2,658	--
EPN Texas operating fee	6,340	--	--
Natural gas storage facilities operating fee	4,004	1,335	--
Indian Basin lateral operating fee	823	--	--
	$33,965	$22,265	$11,726

Poseidon charges were for transportation services related to transporting production from our Garden Banks Block 72 and 117 leases. Viosca Knoll charges in 1999 were for transportation services related to transporting production from our Viosca Knoll 817 Block lease.

Cost Reimbursements. In connection with becoming the operator of Poseidon, we entered into an operating agreement in January 2001. For the years ended December 31, 2000 and 1999, we charged Manta Ray Offshore a management fee pursuant to its management and operations agreements. Under a management agreement between us and Viosca Knoll, prior to our purchase of an additional 49 percent interest in June 1999, we charged Viosca Knoll a base fee of $100,000 annually in exchange for our providing financial, accounting and administrative services on behalf of Viosca Knoll. All fees received under contracts approximate actual costs incurred.

As a result of becoming the operator of Deepwater Holdings' assets during 1999 and 2000, we began receiving reimbursement from Deepwater Holdings for the cost of operating HIOS, UTOS, East Breaks, Stingray, and the West Cameron dehydration facility. This reimbursement is a fixed monthly amount covering normal operating activities that was approved by each subsidiary's management committee and is based on historical operating expenses. We recorded these as a reduction to our operation and maintenance expense. To the extent our costs are more than the monthly reimbursement, our operating expenses will be higher, and to the extent our costs are lower than the monthly reimbursement, our operating expense will be lower. In addition, due to the timing of actual costs, we recognized fluctuations in our results of operations throughout the years.

10. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

We and our subsidiaries and affiliates are named as a defendant in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business. For each of these matters, we evaluate the merits of the case, our exposure to the matter and possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we make the necessary accruals. As new information becomes available, our estimates may change. The impact of these changes may have a material effect on our results of operations. As of December 31, 2001, we had no accruals relating to legal proceedings. Below is a discussion of several of our more significant matters.

We, along with several subsidiaries of El Paso Corporation were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to under report the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties Qui Tam Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss.

We have also been named defendants in Quinque Operating Company, et al v. Gas Pipelines and Their Predecessors, et al, filed in 1999 in the District Court of Stevens County, Kansas. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The Quinque complaint was transferred to the same court handling the Grynberg complaint and has now been sent back to Kansas State Court for further proceedings. A motion to dismiss this case is pending.

While the outcome of the matters discussed above cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters will have a material adverse effect on our financial position, operating results or cash flows.

Environmental

We are subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. We currently do not have any accruals for environmental matters.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will make accruals accordingly.

Regulatory Matters

FERC has jurisdiction over HIOS and the Petal natural gas storage facility with respect to transportation of natural gas, rates and charges, construction of new facilities, extension or abandonment of service and facilities, accounts and records, depreciation and amortization policies, and certain other matters.

HIOS and Petal are currently operating under agreements with their respective customers that provide for rates that have been approved by FERC. HIOS is required to file a rate case with FERC in 2002. Our remaining systems are gathering facilities and, as such, are not currently subject to rate and certificate regulation by FERC.

In September 2001, FERC issued a NOPR that proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. Since HIOS and Petal are interstate facilities as defined by the Natural Gas Act, the proposed regulations, if adopted by FERC, would dictate how HIOS and Petal conduct business and interact with all energy affiliates of El Paso Corporation and us. We cannot predict the outcome of the NOPR, but adoption of the regulations in substantially the form proposed would, at a minimum, place administrative and operational burdens on us. Further, more fundamental changes could be required such as a complete organizational separation or sale of HIOS and Petal.

All of our pipelines are subject to FERC's administration of the "equal access" requirements of the Outer Continental Shelf Lands Act. In addition, the Poseidon and Allegheny systems are subject to regulation under the Hazardous Liquid Pipeline Safety Act. Operations in offshore federal waters are regulated by the United States Department of the Interior.

11. ACCOUNTING FOR HEDGING ACTIVITIES

A majority of our commodity sales and purchases, which relate to sales of oil and natural gas associated with our production operations and purchases and sales of natural gas associated with our EPIA pipeline, are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities. On January 1, 2001, we adopted the provisions of SFAS No. 133, Accounting for Derivatives and Hedging Activities. We did not have any derivative contracts in place at December 31, 2000, and therefore, there was no transition adjustment recorded in our financial statements. During 2001, we entered into cash flow hedges. As of December 31, 2001, the fair value of these cash flow hedges included in accumulated other comprehensive income was an unrealized loss of approximately $1.3 million. We estimate the entire amount will be reclassified from accumulated other comprehensive income to earnings over the next 12 months. Reclassifications occur upon physical delivery of the hedged commodity and the corresponding expiration of the hedge. For the year ended December 31, 2001, there was no ineffectiveness in our cash flow hedges.

In January 2002, Poseidon entered into an interest rate swap to hedge a portion of its debt to reduce its exposure to fluctuations in market interest rates.

12. SUPPLEMENTAL DISCLOSURES TO THE STATEMENT OF CASH FLOWS

Cash paid for interest, net of amounts capitalized were as follows:

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
	(IN THOUSANDS)		
Interest	$41,020	$46,768	$31,696

Noncash investing and financing activities excluded from the statement of cash flows were as follows:

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
	(IN THOUSANDS)		
Acquisition of additional 50 percent interest in Deepwater Holdings			
Working capital acquired	$ 7,494	$ --	$ --
Acquisition of Crystal natural gas storage businesses			
Issuance of Series B preference units	--	170,000	--
Working capital acquired	--	220	--
Acquisition of EPIA			
Working capital acquired	--	(1,673)	--
Acquisition of additional ownership interest in Viosca Knoll			
Issuance of common units	--	--	59,792
Working capital acquired	--	--	(2,400)

13. MAJOR CUSTOMERS

The percentage of our revenue from major customers was as follows:

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
El Paso Field Services	16%	--	--
Alabama Gas Corporation	14%	20%	26%
Shell Offshore	--	13%	--
Kerr-McGee Corporation	--	11%	--
Shell Gas Trading Co.	--	--	21%

The 2001 percentage declines in revenue from some of our major customers in 2000 is primarily attributed to increased revenue from our 2001 operations as a result of acquisitions in 2001, principally the acquisition of the EPN Texas assets and Chaco.

14. BUSINESS SEGMENT INFORMATION:

We segregate our business activities into five distinct operating segments:

- Natural Gas Gathering and Transportation;

- Liquid Transportation and Handling;

- Platforms;

- Natural Gas Storage; and

- Oil and Natural Gas Production.

As a result of our acquisition of EPN Texas in February 2001, we began providing NGL transportation and fractionation services and have shown these activities as a separate segment called Liquid Transportation and Handling. This segment also includes the liquid transportation services of the Allegheny and Poseidon oil pipelines which were previously reflected in the Natural Gas Gathering and Transportation segment and our Chaco cryogenic gas processing plant, which we acquired in October 2001.

With the July 2001 installation of the Prince TLP facility in the Prince Field, we began managing our platform operations separately from our gathering and transportation operations. Accordingly, we have shown our platforms as a separate segment called Platforms. The Prince TLP processes oil and natural gas from the Prince Field. First production flowed through the facility in September 2001. This segment also includes the East Cameron 373, Viosca Knoll 817, Garden Banks 72, and Ship Shoal 331 and 332 platforms which were previously reflected in the Natural Gas Gathering and Transportation segment.

We have restated the prior periods, to the extent practicable, in order to conform to the current business segment presentation. The results of operations for the restated periods are not necessarily indicative of the results that would have been achieved had the revised business structure been in effect during the period.

The accounting policies of the individual segments are the same as those described in Note 1. Since earnings from unconsolidated affiliates can be a significant component of earnings in several of our segments, we have chosen to evaluate segment operating performance based on EBIT instead of operating income. We record intersegment revenues at rates that approximate market. Each of our segments are business units that offer different services and products. They are managed separately, as each requires different technology and marketing strategies. We also measure segment performance using performance cash flows, or an asset's ability to generate cash flow. Performance cash flows should not be considered an alternate to EBIT, or other financial measures as an indicator of operating performance. The following are results as of and for the periods ended December 31:

LIQUID NATURAL GAS TRANSPORTATION NATURAL OIL AND INTERSEGMENT GATHERING & & HANDLING PLATFORM GAS NATURAL GAS ELIMINATIONS TRANSPORTATION SERVICES SERVICES STORAGE PRODUCTION & OTHER(1) TOTAL -------------- --- ----------- -------- --- ----- ---------- ------ ------ ---------- (IN THOUSANDS) FOR THE YEAR ENDED DECEMBER 31, 2001 Revenue from external customers.............. $ 93,550 $ 39,460 $ 23,538 $ 19,373 $26,310 $ -- $ 202,231 Intersegment revenue..... 381 -- 12,620 -- -- (13,001) -- Depreciation, depletion and amortization....... 10,207 7,284 7,142 5,605 7,567 844 38,649 Asset impairment charge................. 3,921 -- -- -- -- -- 3,921 Operating income......... 21,870 25,466 25,582 9,548 2,376 (12,271) 72,571 Earnings (loss) from unconsolidated affiliates............ (9,761) 18,210 -- -- -- -- 8,449 EBIT..................... 26,985 43,676 24,950 9,568 2,376 (9,176) 98,379 Performance cash flows(2).............. 49,549 54,962 32,726 15,173 9,943 (913) 161,440 Assets................... 365,976 393,408 267,864 226,991 45,345 57,686 1,357,270 FOR THE YEAR ENDED DECEMBER 31, 2000 Revenue from external customers.............. $ 63,499 $ 8,307 $ 13,875 $ 6,182 $20,552 $ -- $ 112,415 Intersegment revenue..... 629 -- 12,958 -- -- (13,587) -- Depreciation, depletion and amortization....... 8,062 1,391 4,445 1,868 11,280 697 27,743 Operating income (loss)................. 26,183 6,876 22,491 2,190 (6,956) (8,733) 42,051 Earnings from unconsolidated affiliates............ 10,213 12,718 -- -- -- -- 22,931 EBIT..................... 37,004 21,322 22,491

2,193 (6,956) (8,695)
67,359 Performance cash
flows(2)...............
54,823 28,528 24,686
4,061 2,705 (7,698)
107,105
Assets...................
345,309 65,734 200,166
176,420 53,417 28,425
869,471 FOR THE YEAR
ENDED DECEMBER 31, 1999
Revenue from external
customers..............
$ 20,282 $ 2,029 $
11,383 $ -- $29,965 $ --
$ 63,659 Intersegment
revenue..... 693 --
12,500 -- -- (13,193) --
Depreciation, depletion
and amortization.......
6,335 643 4,082 --
18,894 676 30,630
Operating income
(loss).................
9,694 1,155 15,962 --
(6,545) (9,639) 10,627
Earnings from
unconsolidated
affiliates.............
13,927 18,887 -- -- -- -
- 32,814
EBIT.....................
33,730 20,042 15,962 --
(6,545) (9,287) 53,902
Performance cash
flows(2)...............
44,018 19,989 22,294 --
13,967 (8,963) 91,305
Assets...................
319,345 57,893 123,382 -
- 67,885 15,080 583,585

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(1) Represents intersegment eliminations and other income or assets not associated with our segment activities.

(2) Performance cash flows are determined by taking EBIT and adding or subtracting, as appropriate, cash distributions from unconsolidated affiliates; depreciation, depletion and amortization; earnings from unconsolidated affiliates; and other items. The calculation of performance cash flows for the 2001 period excludes the income recognized from El Paso Corporation's additional consideration related to the sales of our Gulf of Mexico assets, losses incurred on the sales of these assets and the impairment of our Manta Ray pipeline and includes the cash payments we have received from El Paso Corporation in accordance with the sales of our Gulf of Mexico assets. The calculation of performance cash flows for the 2000 period excludes the reversal of a litigation reserve and hedging items and includes the cash received related to insurance proceeds for Poseidon's pipeline rupture. The calculation of performance cash flows for the 1999 period excludes the establishment of a litigation reserve and hedging items.

15. GUARANTOR FINANCIAL INFORMATION

In May 2001, we purchased our general partner's 1.01 percent non-managing ownership interest in twelve of our subsidiaries for $8 million. As a result of this acquisition, all of our subsidiaries, but not our joint ventures, are wholly owned by us. Our revolving credit facility is guaranteed by each of our subsidiaries (excluding our Argo, L.L.C. and Argo I, L.L.C. subsidiaries) and is collateralized by our management agreement, substantially all of our assets, and our general partner's one percent general partner interest. In addition, all of our senior subordinated notes are guaranteed by all of our subsidiaries except Argo and Argo I. We are providing the following condensed consolidating financial information of us (as the issuer) and our subsidiaries as if our current organizational structure were in place for all periods presented. The consolidating eliminations column on our balance sheets eliminate our investment in consolidated subsidiaries, intercompany payables and receivables and other transactions between subsidiaries.

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2001

	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)			
Operating revenues				
Gathering and transportation services.......	$ --	$ --	$ 93,550	$ 93,550
Liquid transportation and handling..........	--	--	39,460	39,460
Platform services..........................	--	8,153	15,385	23,538
Natural gas storage services...............	--	--	19,373	19,373
Oil and natural gas sales..................	--	--	26,310	26,310
	--	8,153	194,078	202,231
Operating expenses				
Cost of natural gas.......................	--	--	51,542	51,542
Operations and maintenance, net............	(200)	2,269	33,479	35,548
Depreciation, depletion and amortization....	323	2,988	35,338	38,649
Asset impairment charge....................	--	--	3,921	3,921
	123	5,257	124,280	129,660
Operating income (loss)......................	(123)	2,896	69,798	72,571
Other income (loss)				
Earnings from unconsolidated affiliates.....	--	--	8,449	8,449
Net loss on sales of assets................	(10,941)	--	(426)	(11,367)
Other income..............................	28,492	--	234	28,726
	17,551	--	8,257	25,808
Income before interest, income taxes and other charges....................................	17,428	2,896	78,055	98,379
Interest and debt income (expense)...........	15,328	(1,588)	(56,870)	(43,130)
Minority interest............................	--	--	(100)	(100)
Net income..................................	$ 32,756	$ 1,308	$ 21,085	$ 55,149

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(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2000

	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)			
Operating revenues				
Gathering and transportation services	$ --	$ --	$ 63,499	$ 63,499
Liquid transportation and handling	--	--	8,307	8,307
Platform services	--	--	13,875	13,875
Natural gas storage services	--	--	6,182	6,182
Oil and natural gas sales	--	--	20,552	20,552
	--	--	112,415	112,415
Operating expenses				
Cost of natural gas	--	--	28,160	28,160
Operations and maintenance, net	(323)	--	14,784	14,461
Depreciation, depletion and amortization	151	--	27,592	27,743
	(172)	--	70,536	70,364
Operating income	172	--	41,879	42,051
Other income				
Earnings from unconsolidated affiliates	--	--	22,931	22,931
Other income	311	--	2,066	2,377
	311	--	24,997	25,308
Income before interest, income taxes and other charges	483	--	66,876	67,359
Interest and debt expense	(70)	(252)	(46,750)	(47,072)
Minority interest	--	--	(95)	(95)
Income tax benefit	--	--	305	305
Net income (loss)	$ 413	$(252)	$ 20,336	$ 20,497

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(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 1999

	ISSUER	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)		
Operating revenues			
Gathering and transportation services	$ --	$ 20,282	$ 20,282
Liquid transportation and handling	--	2,029	2,029
Platform services	--	11,383	11,383
Oil and natural gas sales	--	29,965	29,965
	--	63,659	63,659
Operating expenses			
Operations and maintenance, net	--	22,402	22,402
Depreciation, depletion and amortization	28	30,602	30,630
	28	53,004	53,032
Operating income (loss)	(28)	10,655	10,627
Other income			
Earnings from unconsolidated affiliates	--	32,814	32,814
Net gain on sales of assets	--	10,103	10,103
Other income	218	140	358
	218	43,057	43,275
Income before interest, income taxes and other charges	190	53,712	53,902
Interest and debt expense	--	(35,323)	(35,323)
Minority interest	--	(197)	(197)
Income tax benefit	--	435	435
Net income	$190	$ 18,627	$ 18,817

CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2001

	ISSUER	NON-GUARANTOR SUBSIDIARIES	GUARANTOR SUBSIDIARIES(1)	CONSOLIDATING ELIMINATIONS	CONSOLIDATED TOTAL
	(IN THOUSANDS)				
Current assets					
Cash and cash equivalents	$ 7,406	$ 2,571	$ 3,107	$ --	$ 13,084
Accounts receivable, net					
Trade	--	191	32,971	--	33,162
Affiliate	970,933	2,130	2,150	(952,350)	22,863
Other current assets	2,375	264	(2,082)	--	557
Total current assets	980,714	5,156	36,146	(952,350)	69,666
Property, plant and equipment, net	2,371	152,734	948,322	--	1,103,427
Investment in processing agreement	--	--	119,981	--	119,981
Investments in unconsolidated affiliates	--	--	34,442	--	34,442
Investments in consolidated affiliates	51,960	--	45,849	(97,809)	--
Other noncurrent assets	196,777	1,089	1,887	(169,999)	29,754
Total assets	$1,231,822	$158,979	$1,186,627	$(1,220,158)	$1,357,270
Current liabilities					
Accounts payable					
Trade	$ 587	$ 3,859	$ 10,541	$ --	$ 14,987
Affiliate	--	13,568	948,700	(952,350)	9,918
Accrued interest	5,698	703	--	--	6,401
Current maturities of limited recourse term loan	--	19,000	--	--	19,000
Other current liabilities	(189)	--	4,348	--	4,159
Total current liabilities	6,096	37,130	963,589	(952,350)	54,465
Revolving credit facility	300,000	--	--	--	300,000
Long-term debt	425,000	--	--	--	425,000
Limited recourse term loan, less current maturities	--	76,000	--	--	76,000
Other					

noncurrent liabilities...... --
-- 171,078 (169,999) 1,079
Partners'
capital.................
500,726 45,849 51,960 (97,809)
500,726 ---------- -------- ---
------- ----------- ----------
Total liabilities and partners'
capital..... $1,231,822
$158,979 $1,186,627
$(1,220,158) $1,357,270
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(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2000

	ISSUER	NON-GUARANTOR SUBSIDIARIES	GUARANTOR SUBSIDIARIES(1)	CONSOLIDATING ELIMINATIONS	CONSOLIDATED TOTAL
	(IN THOUSANDS)				
Current assets					
Cash and cash equivalents	$ 18,865	$ 1,416	$ --	$ --	$ 20,281
Accounts receivable, net					
Trade	--	--	39,270	(5,469)	33,801
Affiliate	620,780	(875)	1,602	(619,905)	1,602
Other current assets	390	--	243	--	633
Total current assets	640,035	541	41,115	(625,374)	56,317
Property, plant and equipment, net	1,798	88,356	529,084	--	619,238
Investments in unconsolidated affiliates	--	--	182,734	--	182,734
Investments in consolidated affiliates	156,175	--	44,542	(200,717)	--
Other noncurrent assets	9,498	1,445	239	--	11,182
Total assets	$807,506	$90,342	$797,714	$(826,091)	$869,471
Current liabilities					
Accounts payable					
Trade	$ 1,585	$ 508	$ 18,102	$ (5,469)	$ 14,726
Affiliate	--	--	622,273	(619,905)	2,368
Accrued interest	2,815	292	--	--	3,107
Other current liabilities	(965)	--	3,136	--	2,171
Total current liabilities	3,435	800	643,511	(625,374)	22,372
Revolving credit facility	318,000	--	--	--	318,000
Long-term debt	175,000	--	--	--	175,000
Limited recourse term loan	--	45,000	--	--	45,000
Other noncurrent liabilities	--	--	394	--	394
Minority interest	--	--	(2,366)	--	(2,366)
Partners' capital	311,071	44,542	156,175	(200,717)	311,071
Total liabilities and partners' capital	$807,506	$90,342			

$797,714 $(826,091) $869,471
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(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW
YEAR ENDED DECEMBER 31, 2001

	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)			
Cash flows from operating activities				
Net income	$ 32,756	$ 1,308	$ 21,085	$ 55,149
Adjustments to reconcile net income to net cash provided by operating activities				
Depreciation, depletion and amortization	323	2,988	35,338	38,649
Net loss on sales of assets	10,941	--	426	11,367
Asset impairment charge	--	--	3,921	3,921
Distributed earnings of unconsolidated affiliates				
Earnings from unconsolidated affiliates	--	--	(8,449)	(8,449)
Distributions from unconsolidated affiliates	--	--	35,062	35,062
Other noncash items	3,155	318	835	4,308
Working capital changes, net of effects of acquisitions and non-cash transactions	(9,740)	385	(43,268)	(52,623)
Net cash provided by operating activities	37,435	4,999	44,950	87,384
Cash flows from investing activities				
Acquisitions and development of oil and natural gas properties	--	--	(2,018)	(2,018)
Additions to pipelines, platforms and facilities	(896)	(67,367)	(508,644)	(576,907)
Investments in unconsolidated affiliates	--	--	(1,487)	(1,487)
Cash paid for acquisitions, net of cash acquired	--	--	(28,414)	(28,414)
Proceeds from sale of assets	89,162	--	19,964	109,126
Net cash provided by (used in) investing activities	88,266	(67,367)	(520,599)	(499,700)
Cash flows from financing activities				
Net proceeds from revolving credit facility	559,994	--	--	559,994
Repayments of revolving credit facility	(581,000)	--	--	(581,000)
Net proceeds from issuance of long-term debt	243,032	--	--	243,032
Net proceeds from limited recourse term loan	--	49,960	--	49,960
Advances with affiliates	(492,805)	13,563	479,242	--
Net proceeds from issuance of common units	286,699	--	--	286,699
Redemption of Series B preference units	(50,000)	--	--	(50,000)
Contributions from general partner	2,843	--	--	2,843
Distributions to partners	(105,923)	--	(486)	(106,409)
Net cash provided by (used in) financing activities	(137,160)	63,523	478,756	405,119
Net (decrease) increase in cash and cash				

equivalents.....................................
$ (11,459) $ 1,155 $ 3,107 (7,197) =========
======== ========= Cash and cash equivalents
at beginning of
year...
20,281 --------- Cash and cash equivalents at
end of year........ $ 13,084 =========

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

(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW
YEAR ENDED DECEMBER 31, 2000

	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)			
Cash flows from operating activities				
Net income (loss)	$ 413	$ (252)	$ 20,336	$ 20,497
Adjustments to reconcile net income to net cash provided by operating activities				
Depreciation, depletion and amortization	151	--	27,592	27,743
Distributed earnings of unconsolidated affiliates				
Earnings from unconsolidated affiliates	--	--	(22,931)	(22,931)
Distributions from unconsolidated affiliates	--	--	33,960	33,960
Litigation reserve	(2,250)	--	--	(2,250)
Other noncash items	2,964	--	(727)	2,237
Working capital changes, net of effects of acquisitions and non-cash transactions	(285)	800	(11,361)	(10,846)
Net cash provided by operating activities	993	548	46,869	48,410
Cash flows from investing activities				
Acquisitions and development of oil and natural gas properties	--	--	(172)	(172)
Additions to pipelines, platforms and facilities	(1,811)	(88,356)	(38)	(90,205)
Investments in unconsolidated affiliates	--	--	(8,979)	(8,979)
Cash paid for acquisitions, net of cash acquired	--	--	(26,476)	(26,476)
Other	(402)	--	21	(381)
Net cash used in investing activities	(2,213)	(88,356)	(35,644)	(126,213)
Cash flows from financing activities				
Net proceeds from revolving credit facility	152,043	--	--	152,043
Repayments of revolving credit facility	(125,000)	--	--	(125,000)
Net proceeds from limited recourse term loan	--	43,554	--	43,554
Net proceeds from issuance of common units	100,634	--	--	100,634
Advances with affiliates	(34,765)	45,670	(10,905)	--
Redemption of publicly held preference units	(804)	--	--	(804)
Contribution from general partner	2,785	--	--	2,785
Distributions to partners	(78,529)	--	(801)	(79,330)
Net cash provided by (used in) financing activities	16,364	89,224	(11,706)	93,882
Net increase in cash and cash equivalents	$ 15,144	$ 1,416	$ (481)	16,079
Cash and cash equivalents at beginning of year				4,202
Cash and cash equivalents at end of year				$ 20,281

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(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW
YEAR ENDED DECEMBER 31, 1999

	ISSUER	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)		
Cash flows from operating activities			
Net income	$ 190	$ 18,627	$ 18,817
Adjustments to reconcile net income to net cash (used in) provided by operating activities			
Depreciation, depletion and amortization	28	30,602	30,630
Gain on sales of assets	--	(10,103)	(10,103)
Distributed earnings of unconsolidated affiliates			
Earnings from unconsolidated affiliates	--	(32,814)	(32,814)
Distributions from unconsolidated affiliates	--	46,180	46,180
Litigation reserve	2,250	--	2,250
Other noncash items	2,072	(238)	1,834
Working capital changes, net of effects of acquisitions and non-cash transactions	(6,172)	138	(6,034)
Net cash provided by (used in) operating activities	(1,632)	52,392	50,760
Cash flows from investing activities			
Acquisitions and development of oil and natural gas properties	--	(3,218)	(3,218)
Additions to pipelines, platforms and facilities	(203)	(30,459)	(30,662)
Investments in unconsolidated affiliates	--	(59,348)	(59,348)
Cash paid for acquisitions, net of cash acquired	--	(20,351)	(20,351)
Proceeds from sale of assets	--	26,122	26,122
Distributions related to the formation of Deepwater Holdings	--	20,000	20,000
Other	(130)	452	322
Net cash used in investing activities	(333)	(66,802)	(67,135)
Cash flows from financing activities			
Net proceeds from revolving credit facility	141,126	--	141,126
Repayments of revolving credit facility	(226,850)	--	(226,850)
Advances with affiliates	(15,560)	15,560	--
Net proceeds from issuance of long-term debt	168,878	--	168,878
Contribution from general partner	603	--	603
Distributions to partners	(65,619)	(669)	(66,288)
Net cash provided by financing activities	2,578	14,891	17,469
Net increase in cash and cash equivalents	$ 613	$ 481	1,094
Cash and cash equivalents at beginning of year			3,108
Cash and cash equivalents at end of year			$ 4,202

16. SUPPLEMENTAL OIL AND NATURAL GAS INFORMATION (UNAUDITED):

Oil and Natural Gas Reserves

The following table represents our net interest in estimated quantities of proved developed and proved undeveloped reserves of crude oil, condensate and natural gas and changes in such quantities at year end 2001, 2000 and 1999. Estimates of our reserves at December 31, 2001, 2000 and 1999, have been made by the independent engineering consulting firm, Netherland, Sewell & Associates, Inc. except for the Prince Field for 2001, which was prepared by El Paso Production Company, our affiliate and operator of the Prince Field. Net proved reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our policy is to recognize proved reserves only when economic producibility is supported by actual production. As a result, no proved reserves were booked with respect to any of our producing fields in the absence of actual production. Proved developed reserves are proved reserve volumes that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserve volumes that are expected to be recovered from new wells on undrilled acreage or from existing wells where a significant expenditure is required for recompletion. Reference Rules 4-10(a)(2)(i), (ii), (iii), (3) and (4) of Regulation S-X, for detailed definitions of proved reserves, which can be found at the SEC's website, http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas.

Estimates of reserve quantities are based on sound geological and engineering principles, but, by their very nature, are still estimates that are subject to substantial upward or downward revision as additional information regarding producing fields and technology becomes available.

	OIL/CONDENSATE MBBLS(1)	NATURAL GAS MMCF(1)
Proved reserves -- January 1, 1999	1,578	28,884
Revision of previous estimates	251	623
Extension, Discoveries, and other Additions	1	218
Production	(357)	(12,211)
Proved reserves -- December 31, 1999	1,473	17,514
Revision of previous estimates	23	1,171
Production	(295)	(7,185)
Proved reserves -- December 31, 2000	1,201	11,500
Revision of previous estimates(2)	1,852	5,913
Production(2)	(345)	(4,172)
Proved reserves -- December 31, 2001	2,708	13,241
Proved developed reserves December 31, 1999	1,473	15,061
December 31, 2000	1,201	9,126
December 31, 2001(2)	2,350	10,384

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(1) Includes our overriding royalty interest in proved reserves on Garden Banks Block 73 and the Prince Field.

(2) Includes our overriding royalty interest in proved reserves of 1,341 MBbls of oil and 1,659 MMcf of natural gas on our Prince Field, which began production in 2001. These reserves were not included in proved reserves prior to 2001 because, consistent with our policy, economic producibility had not been supported by actual production. Also, we had increases in estimated proved reserves relating to our producing properties, primarily at our West Delta 35 field. Actual production in the Prince Field for 2001 was 37 MBbls of oil and 32 MMcf of natural gas.

The following are estimates of our total proved developed and proved undeveloped reserves of oil and natural gas by producing property as of December 31, 2001.

	OIL (BARRELS)		NATURAL GAS (MCF)	
	PROVED DEVELOPED	PROVED UNDEVELOPED	PROVED DEVELOPED	PROVED UNDEVELOPED
	(IN THOUSANDS)			
Garden Banks Block 72	277	--	1,900	--
Garden Banks Block 117	1,065	--	1,556	--
Viosca Knoll Block 817	12	--	2,216	2,437
West Delta Block 35	13	--	3,473	--
Prince Field	983	358	1,239	420
Total	2,350	358	10,384	2,857

In general, estimates of economically recoverable oil and natural gas reserves and of the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the subject properties, the assumed effects of regulation by governmental agencies and assumptions concerning future oil and natural gas prices, future operating costs and future plugging and abandonment costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net revenue expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The meaningfulness of such estimates is highly dependent upon the assumptions upon which they are based.

Estimates with respect to proved undeveloped reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves. A significant portion of our reserves is based upon volumetric calculations.

Future Net Cash Flows

The standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves is calculated and presented in accordance with SFAS No. 69, Disclosures About Oil and Gas Producing Activities. Accordingly, future cash inflows were determined by applying year-end oil and natural gas prices, as adjusted for fixed price contracts in effect, to our estimated share of future production from proved oil and natural gas reserves. The average prices utilized in the calculation of the standardized measure of discounted future net cash flows at December 31, 2001, were $16.75 per barrel of oil and $2.62 per Mcf of natural gas. Actual future prices and costs may be materially higher or lower. Future production and development costs were computed by applying year-end costs to future years. As we are not a taxable entity, no future income taxes were provided. A prescribed 10 percent discount factor was applied to the future net cash flows.

In our opinion, this standardized measure is not a representative measure of fair market value, and the standardized measure presented for our proved oil and natural gas reserves is not representative of the reserve value. The standardized measure is intended only to assist financial statement users in making comparisons between companies. In the table following, the amounts of future production costs have been restated to include platform access fees paid to our platform segment. See note 2 to the table for further discussion of the impact of such fees on our consolidated standardized measure of discounted future net cash flows.

	DECEMBER 31, 2001 (RESTATED)	2000 (RESTATED)	1999 (RESTATED)
	(IN THOUSANDS)		
Future cash inflows(1)	$ 80,603	$136,658	$ 69,719
Future production costs(2)	(19,252)	(28,933)	(35,730)
Future development costs	(10,530)	(11,531)	(10,681)
Future net cash flows	50,821	96,194	23,308
Annual discount at 10% rate	(11,761)	(18,488)	(5,479)
Standardized measure of discounted future net cash flows	$ 39,060	$ 77,706	$ 17,829

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(1) Our future cash inflows include estimated future receipts from our overriding royalty interest in our Prince Field and Garden Banks Block 73. Since these are overriding royalty interests, we do not participate in the production or development costs for these fields, but do include their proved reserves, production volumes and future cash inflows in our data.

(2) Our future production costs include platform access fees paid by our oil and natural gas production business to affiliated entities included in our platforms segment. Such platform access fees are eliminated in our consolidated financial statements. The future platform access fees paid to our platform segment were $4,960 for 2001, $13,080 for 2000 and $21,200 for 1999. On a consolidated basis, our standardized measure of discounted future net cash flows was $43,789 for 2001, $89,749 for 2000, and $36,518 for 1999.

Estimated future net cash flows for proved developed and proved undeveloped reserves as of December 31, 2001, are as follows:

	PROVED DEVELOPED (RESTATED)	PROVED UNDEVELOPED (RESTATED)	TOTAL
	(IN THOUSANDS)		
Undiscounted estimated future net cash flows from proved reserves before income taxes	$40,518	$10,303	$50,821
Present value of estimated future net cash flows from proved reserves before income taxes, discounted at 10%	$31,003	$ 8,057	$39,060

The following are the principal sources of change in the standardized measure:

	2001 (RESTATED)	2000 (RESTATED)	1999 (RESTATED)
	(IN THOUSANDS)		
Beginning of year	$ 77,706	$ 17,829	$ 26,672
Sales and transfers of oil and natural gas produced, net of production costs	(34,834)	(33,203)	(22,154)
Net changes in prices and production costs	(55,657)	119,457	29,901
Extensions, discoveries and improved recovery, less related costs	--	--	544
Oil and natural gas development costs incurred during the year	2,018	172	615
Changes in estimated future development costs	535	(511)	(1,098)
Revisions of previous quantity estimates	38,090	7,846	5,124
Accretion of discount	7,771	1,783	2,666
Changes in production rates, timing and other	3,431	(35,667)	(24,441)
End of year	$ 39,060	$ 77,706	$ 17,829

Development, Exploration, and Acquisition Expenditures

The following table details certain information regarding costs incurred in our development, exploration, and acquisition activities during the years ended December 31:

	2001	2000	1999
	(IN THOUSANDS)		
Development costs	$2,018	$172	$3,018
Capitalized interest	--	--	200
Total capital expenditures	$2,018	$172	$3,218

In each of the years presented, we elected not to incur any costs to develop our proved undeveloped reserves. However, we expect to incur approximately $2.6 million within the next three years to develop these reserves.

Capitalized Costs

Capitalized costs relating to our natural gas and oil producing activities and related accumulated depreciation, depletion and amortization were as follows as of December 31:

	2001	2000
	(IN THOUSANDS)	
Oil and natural gas properties		
Proved properties	$ 54,609	$ 53,572
Wells, equipment, and related facilities	104,766	102,748
	159,375	156,320
Less accumulated depreciation, depletion and amortization	108,307	101,161
	$ 51,068	$ 55,159

Results of operations

Results of operations from producing activities by fiscal year were as follows at December 31:

	2001	2000	1999
	(IN THOUSANDS)		
Natural gas sales	$18,248	$12,819	$24,829
Oil, condensate, and liquid sales	8,062	7,733	5,136
Total operating revenues	26,310	20,552	29,965
Production costs(1)	16,367	16,228	17,616
Depreciation, depletion and amortization	7,567	11,280	18,894
Results of operations from producing activities	$ 2,376	$(6,956)	$(6,545)

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(1) These production costs include platform access fees paid to affiliated entities included in our platforms segment. Such platform access fees, which were approximately $10 million in each of the years presented, are eliminated in our consolidated financial statements.

17. SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION:

In previous years, we have reported earnings from unconsolidated affiliates as part of operating revenues. We have changed this presentation as of December 31, 2000, to include earnings from unconsolidated affiliates as other income. This change has been reflected for all periods presented.

	QUARTER ENDED (UNAUDITED)				
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31	YEAR
	(IN THOUSANDS, EXCEPT PER UNIT DATA)				
2001					
Operating revenues	$54,502	$44,987	$43,126	$59,616	$202,231
Operating income	13,609	16,312	18,107	24,543	72,571
Net income	12,973	11,844	12,037	18,295	55,149
Net income allocated to general partner	4,695	5,904	5,814	8,248	24,661
Net income allocated to Series B preference unitholders	4,322	4,464	4,538	3,904	17,228
Net income allocated to limited partners	3,956	1,476	1,685	6,143	13,260
Basic and diluted net income per unit	0.12	0.04	0.05	0.17	0.38
Distributions declared per common unit	0.5500	0.5750	0.5750	0.6125	2.3125
Weighted average number of units outstanding	32,471	34,070	34,245	36,209	34,376
2000					
Operating revenues	$18,950	$26,812	$29,642	$37,011	$112,415
Operating income	9,394	13,419	10,032	9,206	42,051
Net income	1,939	8,367	4,862	5,329	20,497
Net income allocated to general partner	3,232	3,622	4,114	4,610	15,578
Net income allocated to Series B preference unitholders	--	--	1,417	4,251	5,668
Net (loss) income allocated to limited partners	(1,293)	4,745	(669)	(3,532)	(749)
Basic and diluted net (loss) income per unit	(0.05)	0.18	(0.02)	(0.11)	(0.03)
Distributions declared per common unit	0.5250	0.5375	0.5375	0.5500	2.1500
Distributions declared per preference unit	0.2750	0.2750	0.2750	--	0.8250
Weighted average number of units outstanding	27,029	27,029	31,229	31,550	29,077

REPORT OF INDEPENDENT ACCOUNTANTS

To the Unitholders of El Paso Energy Partners, L.P.
and the Board of Directors and Stockholder of
El Paso Energy Partners Company, as General Partner:

In our opinion, the consolidated financial statements listed in the index appearing under Item 14(a)1. on page 111 present fairly, in all material respects, the financial position of El Paso Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As disclosed in Note 1 to the consolidated financial statements, the Partnership changed its method for allocating net income to its partners in 1999.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 28, 2002

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) THE FOLLOWING DOCUMENTS ARE FILED AS PART OF THIS ANNUAL REPORT OR INCORPORATED BY REFERENCE:

1. Financial Statements

Our consolidated financial statements are included in Part II, Item 8 of this report:

PAGE ----
Consolidated Statements of Income.......................... 15
Consolidated Balance Sheets................................. 16
Consolidated Statements of Cash Flows...................... 17
Consolidated Statements of Partners' Capital................ 18
Consolidated Statements of Comprehensive Income and Changes in Accumulated Other Comprehensive Income................. 19
Notes to Consolidated Financial Statements.................. 20
Report of Independent Accountants.......................... 64

The following financial statements of our equity investment is included on the following pages of this report:

PAGE ----
POSEIDON OIL PIPELINE COMPANY, L.L.C.
Reports of Independent Accountants....................... 67
Statements of Income.................................... 69
Balance Sheets.. 70
Statements of Cash Flows................................ 71
Statements of Members' Capital.......................... 72
Notes to Financial Statements........................... 73

2. Financial statement schedules and supplementary information required to be submitted.

None. All financial statement schedules are omitted because the information is not required, is not material or is otherwise included in the consolidated financial statements or notes thereto included elsewhere in this Annual Report.

3. Exhibit list.. 78

POSEIDON OIL PIPELINE COMPANY, L.L.C.

FINANCIAL STATEMENTS
WITH REPORT OF INDEPENDENT ACCOUNTANTS
DECEMBER 31, 2001

REPORT OF INDEPENDENT ACCOUNTANTS

To the Members of Poseidon Oil Pipeline Company, L.L.C.:

In our opinion, the accompanying balance sheet and the related statements of income, members' capital and cash flows present fairly, in all material respects, the financial position of Poseidon Oil Pipeline Company, L.L.C. (the "Company") at December 31, 2001, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion. The financial statements of the Company as of December 31, 2000 and for the two years in the period ended December 31, 2000 were audited by other independent accountants whose report dated March 16, 2001 expressed an unqualified opinion on those statements.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 28, 2002

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Members of
Poseidon Oil Pipeline Company, L.L.C.:

We have audited the accompanying balance sheet of Poseidon Oil Pipeline Company, L.L.C. (a Delaware limited liability company), as of December 31, 2000, and the related statements of income, members' equity and cash flows for the years ended December 31, 2000 and 1999. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Poseidon Oil Pipeline Company, L.L.C., as of December 31, 2000, and the results of its operations and its cash flows for the years ended December 31, 2000 and 1999, in conformity with accounting principles generally accepted in the United States.

/s/ ARTHUR ANDERSEN LLP

Houston, Texas
March 16, 2001

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF INCOME
(IN THOUSANDS)

	FOR THE YEARS ENDED DECEMBER 31,		
	2001	2000	1999
Operating revenues			
Transportation and crude oil sales....................	$1,196,840	$1,466,086	$1,108,124
Operating expenses			
Crude oil purchases..................................	1,125,324	1,400,928	1,034,330
Transportation costs..................................	1,115	1,793	3,452
Operation and maintenance.............................	1,586	4,487	4,188
Repair expenses..	--	18,118	--
Depreciation and amortization.........................	10,552	10,754	6,172
	1,138,577	1,436,080	1,048,142
Operating income..	58,263	30,006	59,982
Other income (expense)..................................			
Interest income..	394	639	404
Interest and debt expense.............................	(7,668)	(11,683)	(9,133)
Net income..	$ 50,989	$ 18,962	$ 51,253

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

BALANCE SHEETS
AS OF DECEMBER 31, 2001 AND 2000
(IN THOUSANDS)

	2001	2000
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,095	$ 2,532
Accounts receivable, trade	51,497	66,917
Accounts receivable, affiliate	36,563	53,291
Other current assets	2,212	2,585
Total current assets	91,367	125,325
Property, plant and equipment, net	222,363	232,791
Debt reserve fund	3,499	6,239
Other noncurrent assets	708	--
Total assets	$317,937	$364,355
LIABILITIES AND MEMBERS' CAPITAL		
Current liabilities		
Accounts payable, trade	$ 43,574	$ 62,494
Accounts payable, affiliate	36,791	52,282
Current maturities of revolving credit facility	--	150,000
Total current liabilities	80,365	264,776
Revolving credit facility	150,000	--
Reserve for revenue refund	--	1,297
Commitments and contingencies		
Members' capital	87,572	98,282
Total liabilities and members' capital	$317,937	$364,355

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	FOR THE YEARS ENDED DECEMBER 31,		
	2001	2000	1999
Cash flows from operating activities			
Net income	$ 50,989	$ 18,962	$ 51,253
Adjustments to reconcile net income to cash provided by operating activities			
Depreciation and amortization	10,552	10,754	6,172
Changes in operating assets and liabilities			
Decrease (increase) in accounts receivable	32,148	48,828	(128,640)
Decrease (increase) in other current assets	373	(2,993)	395
(Decrease) increase in accounts payable	(34,411)	(44,491)	119,731
(Decrease) increase in reserve for revenue refund	(1,297)	975	322
Decrease in other current liabilities	--	(93)	(505)
Net cash provided by operating activities	58,354	31,942	48,728
Cash flows from investing activities			
Capital expenditures	(124)	(3,323)	(16,606)
Construction advances to operator, net	--	4	1,230
Net cash used in investing activities	(124)	(3,319)	(15,376)
Cash flows from financing activities			
Proceeds from issuance of debt	--	--	20,000
Repayments of long-term debt	--	--	(1,000)
Debt issue costs	(708)	--	--
Cash contributions	--	10,900	--
Distributions to partners	(61,699)	(37,588)	(50,531)
Decrease (increase) in debt reserve fund	2,740	(1,456)	(454)
Net cash used in financing activities	(59,667)	(28,144)	(31,985)
Increase (decrease) in cash and cash equivalents	(1,437)	479	1,367
Cash and cash equivalents:			
Beginning of period	2,532	2,053	686
End of period	$ 1,095	$ 2,532	$ 2,053
Supplemental disclosure of cash flow information			
Cash paid for interest, net of amounts capitalized	$ 6,423	$ 11,683	$ 8,730

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF MEMBERS' CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999
(IN THOUSANDS)

	EQUILON ENTERPRISES, L.L.C. (36%)	MARATHON OIL COMPANY (36%)	POSEIDON PIPELINE COMPANY, L.L.C. (28%)	TOTAL
Balance at December 31, 1998..........	$ 37,903	$ 37,903	$ 29,480	$105,286
Cash distributions..................	(18,191)	(18,191)	(14,149)	(50,531)
Net income..........................	18,451	18,451	14,351	51,253
Balance at December 31, 1999..........	38,163	38,163	29,682	106,008
Cash contributions..................	3,924	3,924	3,052	10,900
Cash distributions..................	(13,532)	(13,532)	(10,524)	(37,588)
Net income..........................	6,826	6,826	5,310	18,962
Balance at December 31, 2000..........	35,381	35,381	27,520	98,282
Cash distributions..................	(22,212)	(22,212)	(17,275)	(61,699)
Net income..........................	18,356	18,356	14,277	50,989
Balance at December 31, 2001..........	$ 31,525	$ 31,525	$ 24,522	$ 87,572

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

NOTES TO FINANCIAL STATEMENTS

NOTE 1 -- ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Poseidon Oil Pipeline Company, L.L.C. is a Delaware limited liability company, formed in February 1996, to design, construct, own and operate the unregulated Poseidon Pipeline extending from the Gulf of Mexico to onshore Louisiana.

Our current members are Equilon Enterprises, L.L.C. (Equilon), Poseidon Pipeline Company, L.L.C. (Poseidon), a subsidiary of El Paso Energy Partners, L.P., and Marathon Pipeline Company (MPLC), which own 36 percent, 36 percent, and 28 percent in us.

Equilon was our operator from January 1, 1998 to December 31, 2000. Effective January 1, 2001, Manta Ray Gathering Company, L.L.C., a subsidiary of El Paso Energy Partners became our operator.

We are in the business of transporting crude oil in the Gulf of Mexico in accordance with various purchase and sale contracts with producers served by our pipeline. We buy crude oil at various points along the pipeline and resell the crude oil at a destination point in accordance with each individual contract. Our margin is earned based upon the differential between the sales price and the purchase price and represents our earnings from providing transportation services. Differences between measured purchased and sold volumes in any period are recorded as changes in exchange imbalances with producers. In addition, we transport crude oil for a fee.

Basis of Presentation

Our financial statements are prepared on the accrual basis of accounting in conformity with accounting principles generally accepted in the United States. Our financial statements for previous periods include reclassifications that were made to conform to the current year presentation. Those reclassifications have no impact on reported net income or members' capital.

Cash and Cash Equivalents

We consider short-term investments with little risk of change in value because of changes in interest rates and purchased with an original maturity of less than three months to be considered cash equivalents.

Debt Reserve Fund

In connection with our revolving credit facility, we are required to maintain a debt reserve account as collateral on the outstanding balances. At December 31, 2001 and 2000, the balance in the account was approximately $3.5 million and $6.2 million, and consisted of funds earning interest at 1.7% and 6.1%.

Allowance for Doubtful Accounts

Collectibility of accounts receivable is reviewed regularly and an allowance is recorded as necessary, primarily under the specific identification method. At December 31, 2001 and 2000, no allowance for doubtful accounts was recorded.

Property, Plant and Equipment

Contributed property, plant and equipment is recorded at fair value as agreed to by the members at the date of contribution. Acquired property, plant and equipment is recorded at cost. Pipeline equipment is depreciated using a composite, straight-line method over the estimated useful lives of 3 to 30 years. Line-fill is not depreciated, as our management believes the cost of all barrels is fully recoverable. Repair and maintenance costs are expensed as incurred, while additions, improvements and replacements are capitalized. No gain or loss is recognized on normal asset retirements under the composite method.

Asset Impairment

We evaluate the impairment of assets in accordance with SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of. If an adverse event or change in circumstances occurs, we make an estimate of our future cash flows from our assets, grouped together at the lowest level for which separate cash flows can be measured, to determine if the asset is impaired. If the total of the undiscounted future cash flows is less than the carrying amount for the assets, we calculate the fair value of the assets either through reference to similar asset sales, or by estimating the fair value using a discounted cash flow approach. These cash flow estimates require us to make estimates and assumptions for many years into the future for pricing, demand, competition, operating costs, legal, regulatory and other factors. On January 1, 2002, we adopted the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. A discussion of this pronouncement follows at the end of this note.

Debt Issue Costs

Debt issue costs are capitalized and amortized over the life of the related indebtedness. Any unamortized debt issue costs are expensed at the time the related indebtedness is repaid or terminated.

Fair Value of Financial Instruments

The estimated fair values of all financial instruments approximate their carrying amounts in the accompanying balance sheet due to the short-term maturity of these instruments.

Revenue Recognition

Revenue from crude oil sales is recognized upon delivery. Revenue from pipeline transportation of hydrocarbons is recognized upon receipt of the hydrocarbons into the pipeline system.

Crude Oil Imbalances

In the course of providing transportation services for customers, we may receive different quantities of crude oil than the quantities delivered. These transactions result in imbalances that are settled in kind the following month.

Environmental Costs

Expenditures for ongoing compliance with environmental regulations that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, and which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated.

Accounting for Price Risk Management Activities

We have adopted SFAS No. 133 beginning January 1, 2001, which requires us to measure all derivative instruments at their fair value, and classify them as either assets or liabilities on our balance sheet, with corresponding offset to income or other comprehensive income depending on their designation, their intended use, or their ability to qualify as hedges under the standard. We have determined that there is no impact on us as of December 31, 2001.

Income Taxes

We are organized as a Delaware limited liability company and treated as a partnership for income tax purposes, and as a result, the income or loss resulting from our operations for income tax purposes is includable in the federal and state tax returns of our members. Accordingly, no provision for income taxes has been recorded in the accompanying financial statements.

Management's Use of Estimates

The preparation of our financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that effect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities that exist at the date of our financial statements. While we believe our estimates are appropriate, actual results can, and often do, differ from those estimates.

Cash Distributions

At times, we may make cash distributions to our members in amounts determined by our Management Committee, which is responsible for conducting our affairs in accordance with our limited liability agreement. Our income is allocated to our members based on their ownership percentages.

Limitations of Member's Liability

As a limited liability company, our members or their affiliates are not personally liable for any of our debts, obligations or liabilities simply because they are our members.

Recent Pronouncements

In July 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. This statement requires companies to record a liability relating to the retirement and removal of assets used in their business. The liability is discounted to its present value, and the related asset value is increased by the amount of the resulting liability. Over the life of the asset, the liability will be accreted to its future value and eventually extinguished when the asset is taken out of service. The provisions of this statement are effective for fiscal years beginning after June 15, 2002. We are currently evaluating the effects of this pronouncement.

In October 2001, the FASB issued SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. This statement requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less cost to sell. The standard also expanded the scope of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of this statement are effective for fiscal years beginning after December 15, 2001. The provisions of this pronouncements will impact any asset dispositions we make after January 1, 2002.

NOTE 2 -- PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

	DECEMBER 31, 2001	DECEMBER 31, 2000
	(IN THOUSANDS)	
Pipeline and equipment, at cost	$266,614	$266,614
Construction work in progress	706	582
	267,320	267,196
Less accumulated depreciation	(44,957)	(34,405)
Total property, plant and equipment, net	$222,363	$232,791

During 2001 and 2000, we did not capitalize interest costs into property, plant and equipment.

NOTE 3 -- LONG-TERM DEBT

In April 2001, we amended and restated our revolving credit facility to provide up to $185 million for construction and expansion of our system and for other working capital changes. Our ability to borrow money under this facility is subject to certain customary terms and conditions, including borrowing base limitations. This facility is collateralized by a substantial portion of our assets and matures in April 2004. As of December 31, 2001, we had $150 million outstanding under this facility with the full unused amount available. The average variable floating interest rate was 3.9% and 7.9% at December 31, 2001 and 2000. We pay a variable commitment fee on the unused portion of the credit facility. The fair value of our revolving credit facility with variable interest rates approximates its carrying value because of the market based nature of our debt's interest rates.

In January 2002, we entered into a two-year interest rate swap to fix the interest rate on $75 million of our variable rate revolving credit facility at 3.49 percent through January 2004. This swap will be accounted for in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, beginning in the first quarter 2002.

NOTE 4 -- MAJOR CUSTOMERS

The percentage of our transportation services and crude oil sales revenues from major customers were as follows:

	FOR THE YEAR ENDED DECEMBER 31, 2001	2000	1999
	% OF TOTAL REVENUES	% OF TOTAL REVENUES	% OF TOTAL REVENUES
Marathon Oil Company	20%	17%	31%
Amerada Hess Company	16%	19%	12%
Equiva Trading Company	15%	16%	12%
Texon L.P.	10%	12%	--
Anadarko	10%	--	--
British-Borneo USA, Inc.	--	11%	--

NOTE 5 -- RELATED PARTY TRANSACTIONS

We derive a portion of our gross sales and gross purchases from our members and their affiliated companies. We generated approximately $489 million in gross affiliated sales and approximately $489 in gross affiliated purchases for 2001. During 2000 and 1999, we generated approximately $30 million and $41 million of net margin from related parties. The decline in margin for 2001 is due to us purchasing more oil from our related parties than we actually sold to our related parties. The excess purchases were sold to third party customers.

We paid Manta Ray Gathering Company, L.L.C., a subsidiary of El Paso Energy Partners approximately $2.1 million for management, administrative and general overhead in 2001. Prior to Manta Ray Gathering Company, L.L.C., taking over as operator, Equilon received approximately $1.1 million and $1.2 million in 2000 and 1999, respectively, for management, administrative and general overhead. During 2000, we paid Equilon an additional management fee of approximately $1.7 million associated with the repair of our ruptured pipeline.

NOTE 6 -- COMMITMENTS AND CONTINGENCIES

In the normal course of business, we are involved in various legal actions arising from our operations. In the opinion of management, the outcome of these legal actions will not have a significant adverse effect on our financial position or results of operations.

We are subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will make accruals accordingly.

We are subject to regulation under the Outer Continental Shelf Lands Act, which calls for nondiscriminatory transportation on pipelines operating in the outer continental shelf region of the Gulf of Mexico and regulation under the Hazardous Liquid Pipeline Safety Act. Operations in offshore federal waters are regulated by the United States Department of the Interior.

In February 1998, we entered into an oil purchase and sale agreement with Pennzoil Exploration and Production (Pennzoil). The agreement provides that if Pennzoil delivers at least 7.5 million barrels by September 2003, we will refund $0.51 per barrel for all barrels delivered plus interest at 8 percent. Based on barrels delivered through December 31, 2001 and our estimates through September 2003, we believe Pennzoil will not meet its minimum delivery requirement. Accordingly, we reversed our accrual for revenue refund of $1.7 million at December 31, 2001 and recorded it as a component of operating revenue.

In January 2000, an anchor from a submersible drilling unit of Transocean 96 (Transocean) in tow ruptured our 24-inch crude oil pipeline north of the Ship Shoal 332 platform. The accident resulted in the release of approximately 2,200 barrels of crude oil in the waters surrounding our system, caused damage to the Ship Shoal 332 platform, and resulted in the shutdown of our system. Our cost to repair the damaged pipeline and clean up the crude oil released into the Gulf of Mexico was approximately $18 million and was charged to repair expenses in the year ended December 31, 2000. By the end of the first quarter 2000, our pipeline was repaired and placed back into service. We have filed a lawsuit against Transocean for damages to the pipeline. The outcome of this litigation is still pending.

EL PASO ENERGY PARTNERS, L.P.

EXHIBIT LIST
DECEMBER 31, 2001

Each exhibit identified below is filed as a part of this amendment to Annual Report on Form 10-K/A. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

EXHIBIT NUMBER DESCRIPTION
----------- -----------
3.A -- Amended and Restated Certificate of Limited Partnership dated February 14, 2002. (Exhibit 3.A to our Annual Report on Form 10-K dated March 7, 2002).
3.B -- Second Amended and Restated Agreement of Limited Partnership effective as of August 31, 2000 (Exhibit 3.B to our Report on Form 8-K dated March 6, 2001).
4.A -- A/B Exchange Registration Rights Agreement dated as of May 27, 1999 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors, Donaldson, Lufkin & Jenrette Securities Corporation, and Chase Securities Inc. (Exhibit

4.7 to our Registration Statement on Form S-4, filed on June 21, 1999, File Nos. 333-81143 through 333-81143-17). 4.B -- A/B Exchange Registration Rights Agreement dated as of May 17, 2001 between El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors listed on Schedule A thereto, Credit Suisse First Boston Corporation, Goldman, Sachs & Co., and J.P. Morgan Securities Inc. (Exhibit 4.3 to our Registration Statement on Form S-4, filed on June 25, 2001, Registration Nos. 333-63800 through 333-63800-20). 4.C -- Registration Rights Agreement dated as of August 28, 2000 by and between Crystal Gas Storage, Inc. and El Paso Energy Partners, L.P. (Exhibit 4.3 to our 2000 Form 10-K). 4.D -- Indenture dated as of May 27, 1999 among

El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors and Chase Bank of Texas, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4, filed on June 24, 1999, File Nos. 333-81143 through 333-81143-17); First Supplemental Indenture dated as of June 30, 1999 (Exhibit 4.2 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999 File Nos. 333-81143 through 333-81143-17); Second Supplemental Indenture dated as of July 27, 1999 (Exhibit 4.3 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999, File Nos. 333-81143 through 333-81143-17); Third Supplemental Indenture dated as of March 21, 2000, to the Indenture dated as of May 27, 1999, (Exhibit 4.7.1 to our 2000

Second Quarter Form 10-Q); Fourth Supplemental Indenture dated as of July 11, 2000. (Exhibit 4.2.1 to our 2001 Third Quarter Form 10-Q); Fifth Supplemental Indenture dated as of August 30, 2000 (Exhibit 4.2.2 to our 2001 Third Quarter Form 10-Q). 4.E -- Indenture dated as of May 11, 2000 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, The Subsidiary Guarantors named therein and The Chase Manhattan Bank, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4 filed June 25, 2001, Registration Nos. 333-63800 through 333-63800-20). 4.F -- Letter agreement dated March 5, 2002, between Crystal Gas Storage, Inc. and El Paso Energy Partners, LP. (Exhibit 4.F to our Annual Report on Form 10-K dated March 7, 2002).

EXHIBIT NUMBER DESCRIPTION - ------------------------

10.A -- First Amended and Restated Management Agreement, dated June 27, 1994 and effective as of July 1, 1992, between DeepTech International Inc. and the General Partner (Exhibit 10.1 to DeepTech's 1994 Form 10-K); First Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.76 to DeepTech's Registration Statement on Form S-1, filed on January 23, 1995, File No. 33-88688); Second Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.18 to our 1995 Form 10-K); Third Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.4 to our Registration Statement on Form S-4, filed on June 21, 1999, File No. 333-81143); Fourth Amendment to

First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.1 to our 1997 Second Quarter Form 10-Q); Fifth Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.1 our 1997 Third Quarter Form 10-Q); Sixth Amendment to First Amended and Restated Management Agreement between DeepTech International Inc. and the General Partner (Exhibit 10.2 to our 1998 Form 10-K).

10.B -- Fifth Amended and Restated Credit Agreement dated as of March 23, 1995, as amended and restated through May 16, 2001 by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, Credit Lyonnais New York Branch and First Union National Bank as Co-Syndication Agents, Fleet National Bank and Fortis Capital Corp., as Co-Documentation Agents, The Chase Manhattan Bank, as Administrative Agent, and the several banks and other financial institutions signatories thereto. (Exhibit 10.2 to our 2001 Third Quarter Form 10-Q); First Amendment to Fifth Amended and Restated Credit Agreement dated as of October 10, 2001 (Exhibit 10.2.1 to our 2001 Third Quarter Form 10-Q). 10.C -- Credit Agreement dated as of August 23, 2000 by and among Argo, L.L.C., the lenders party thereto, the Chase Manhattan Bank, as administrative agent, First Union National Bank, as syndication agent, Bank One, N.A., as documentation agent, and Chase Securities Inc., as arranger (Exhibit 10.14 to our 2000 Third Quarter Form 10-Q). 10.D -- Sponsor Agreement dated as of August 23, 2000, by El Paso Energy Partners, L.P., and the Chase Manhattan Bank, as administrative agent (Exhibit 10.15 to our 2000 Third Quarter Form 10-Q). 10.E -- Redemption Agreement dated February 27, 1998 between Tatham Offshore, Inc. and

Flextrend Development Company, L.L.C., a subsidiary of El Paso Energy Partners, L.P. (Exhibit 10.1 our 1998 Third Quarter Form 10-Q). 10.F -- Farmout Agreement dated October 25, 1999 by and between Flextrend Development Company, L.L.C. and El Paso Production GOM, Inc. (Exhibit 10.15 to our Report on Form 8-K, filed on November 15, 1999). 10.G -- Limited Liability Company Agreement for Poseidon Oil Pipeline Company, L.L.C. dated February 14, 1996; First Amendment to the Limited Liability Company Agreement for Poseidon Oil Pipeline Company, L.L.C. dated February 14, 1996. (Exhibit 10.14 to our 2000 Second Quarter Form 10-Q). 10.H -- Fabrication Agreement dated as of July 16, 1999 by and between Delos Offshore Company and MODEC International LLC; Amendment No. 1 to the Fabrication Agreement dated as of August 31, 1999 by and between Delos Offshore Company and MODEC International

LLC. (Exhibit 10.20 to our 2000 Second Quarter Form 10-Q).

EXHIBIT NUMBER DESCRIPTION
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-- 10.I -- Purchase and Sale Agreement dated as of September 27, 2001 by and between American Natural Offshore Company, Texas Offshore Pipeline System, Inc., Unitex Offshore Transmission Company and ANR Western Gulf Holdings, L.L.C. as Sellers and El Paso Energy Partners Deepwater, L.L.C., as Buyer (Exhibit 2.1 to our Report on Form 8-K dated October 25, 2001). 10.J -- Assignment, Acceptance and Amendment dated October 4, 2001 by and between Delos Offshore Company, L.L.C., a Delaware limited liability company, The Chase Manhattan Bank, KBC Bank N.V., The Sumitomo Bank, Limited, Royal Bank of Canada, The Bank of New York, Societe Generale, Southwest Agency, Societe Generale Financial

Corporation, The Industrial Bank of Japan, Limited New York Branch, El Paso New Chaco Company, L.L.C., El Paso Natural Gas Company, El Paso Corporation, The Chase Manhattan Bank, in its capacity as Agent, and the State Street Bank and Trust Company, not in its individual capacity but solely as trustee for the Chaco Liquids Plant Trust (Exhibit 2.2 to our Report on Form 8-K dated October 25, 2001). 10.K -- Tolling Agreement dated as of October 1, 2001 between El Paso Field Services, L.P., and Delos Offshore Company, L.L.C. (Exhibit 2.3 to our Report on Form 8-K dated October 25, 2001). 10.L+ -- 1998 Unit Option Plan for Non-Employee Directors Amended and Restated effective as of April 18, 2001. (Exhibit 10.1 to our 2001 Second quarter Form 10-Q). 10.M+ -- 1998 Omnibus Compensation Plan, Amended and Restated, effective as of January 1, 1999 (Exhibit 10.9 to our 1998 Form 10-K); Amendment No. 1 dated as of December 1, 1999. (Exhibit 10.8.1 our 2000 Second Quarter Form 10-Q). 21. -- Subsidiaries of El Paso Energy Partners, L.P. (Exhibit 21. to our Annual Report on Form 10-K dated March 7, 2002.) 23.A -- Consent of Independent Accountants. (Exhibit 23.A to our Annual Report on Form 10-K dated March 7, 2002.) 23.B -- Consent of Independent Petroleum Engineers. (Exhibit 23.B to our Annual Report on Form 10-K dated March 7, 2002.) *99.A -- Certification of the Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. *99.B -- Certification of the Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the

Sarbanes-
Oxley Act of
2002.

(b) REPORTS ON FORM 8-K

- We filed a current report on Form 8-K dated October 4, 2001, announcing that we had entered into a series of transactions to acquire midstream assets for $284 million and would raise the annual distribution to $2.45 per common unit.

- We filed a current report on Form 8-K dated October 19, 2001, in order (a) to include in our current risk factors a discussion of the potential effect of regulations proposed by the Federal Energy Regulatory Commission, or FERC, as well as risks associated with our newly-acquired Chaco cryogenic natural gas processing plant and (b) to disclose our authorization of the issuance of unit options.

- We filed a current report on Form 8-K dated October 19, 2001, providing unaudited pro forma condensed consolidated and combined financials for our acquisition of the remaining 50 percent interest in Deepwater Holdings, L.L.C., and our acquisition of the Chaco cryogenic natural gas processing plant; our acquisition of the Crystal natural gas storage business and the natural gas liquids transportation and fractionation assets; our sale of several Gulf of Mexico assets; and our issuance of 5,627,070 common units, which includes 1,477,070 common units to be purchased by our general partner.

- We filed a current report on Form 8-K dated October 25, 2001, to announce our acquisition of (a) title to and other interests in the Chaco cryogenic natural gas processing plant in northern New Mexico's San Juan Basin and (b) the remaining 50 percent indirect interest that we did not already own in Deepwater Holdings, L.L.C., through which the High Island Offshore System and East Breaks natural gas gathering system became indirectly wholly-owned assets.

- We filed a current report on Form 8-K dated October 25, 2001, to file consents from experts with respect to reports incorporated by reference into our Registration Statement on Form S-3 (File No. 333-85987).

- We filed a current report on Form 8-K dated October 30, 2001, to announce that we entered into an Underwriting Agreement with our General Partner and the underwriters named therein in connection with our public offering of up to 4,772,500 common units representing limited partner interests.

- We filed a current report on Form 8-K/A dated November 8, 2001, providing unaudited proforma financial statements for our acquisition of the remaining 50 percent interest in Deepwater Holdings, L.L.C., and our acquisition of title to and other interests in the Chaco cryogenic natural gas processing plant; our acquisition of the Crystal natural gas storage business and the natural gas liquids transportation and fractionation assets; and our sale of several Gulf of Mexico assets. We also provided unaudited Deepwater Holdings, L.L.C. financial statements as of and for the periods ended June 30, 2001 and 2000.

- We filed a current report on Form 8-K dated December 14, 2001, announcing our 2001 earnings expectations and the anticipated acquisition of additional midstream businesses from El Paso Corporation, including the EPGT Texas Pipeline, in early 2002.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, El Paso Energy Partners, L.P. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 2nd day of January 2003.

EL PASO ENERGY PARTNERS, L.P.
(Registrant)

By: EL PASO ENERGY PARTNERS COMPANY,
its General Partner

By: /s/ ROBERT G. PHILLIPS
Robert G. Phillips
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of El Paso Energy Partners, L.P. and in the capacities and on the dates indicated:

NAME TITLE DATE ---- ----- ---- /s/ ROBERT G. PHILLIPS Chief Executive Officer and January 2, 2003 - --- ---------- ---------- ---------- ---------- ---------- Chairman of the Board and Robert G. Phillips Director /s/ JAMES H. LYTAL President and Director January 2, 2003 - --- ---------- ---------- ---------- ---------- ---------- James H. Lytal /s/ KEITH B. FORMAN Chief Financial Officer and January 2, 2003 - --- ---------- ---------- ---------- ---------- ---------- Vice President Keith B. Forman /s/ D. MARK LELAND

Senior
Vice
President
and
January 2,
2003 - ---

Controller
(Principal
D. Mark
Leland
Accounting
Officer)
/s/
MICHAEL B.
BRACY
Director
January 2,
2003 - ---

Michael B.
Bracy /s/
H. DOUGLAS
CHURCH
Director
January 2,
2003 - ---

H. Douglas
Church /s/
KENNETH L.
SMALLEY
Director
January 2,
2003 - ---

Kenneth L.
Smalley

CERTIFICATION

I, Robert G. Phillips, certify that:

1. I have reviewed this amendment to our annual report on Form 10-K/A of El Paso Energy Partners, L.P.;

2. Based on my knowledge, this amendment to our annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this amendment to our annual report; and

3. Based on my knowledge, the financial statements, and other financial information included in this amendment to our annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this amendment to our annual report.

Date: January 2, 2003

/s/ ROBERT G. PHILLIPS

Robert G. Phillips
Chief Executive Officer
El Paso Energy Partners Company,
general partner of El Paso Energy
Partners, L.P.

CERTIFICATION

I, Keith B. Forman, certify that:

1. I have reviewed this amendment to our annual report on Form 10-K/A of El Paso Energy Partners, L.P.;

2. Based on my knowledge, this amendment to our annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this amendment to our annual report; and

3. Based on my knowledge, the financial statements, and other financial information included in this amendment to our annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this amendment to our annual report.

Date: January 2, 2003

/s/ KEITH B. FORMAN

Keith B. Forman
Chief Financial Officer
El Paso Energy Partners Company,
general partner of El Paso Energy
Partners, L.P.

EL PASO ENERGY PARTNERS, L.P.

INDEX TO EXHIBITS
DECEMBER 31, 2001

Each exhibit identified below is filed as a part of this amendment to Annual Report on Form 10-K/A. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

EXHIBIT NUMBER DESCRIPTION
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3.A -- Amended and Restated Certificate of Limited Partnership dated February 14, 2002. (Exhibit 3.A to our Annual Report on Form 10-K dated March 7, 2002).
3.B -- Second Amended and Restated Agreement of Limited Partnership effective as of August 31, 2000 (Exhibit 3.B to our Report on Form 8-K dated March 6, 2001).
4.A -- A/B Exchange Registration Rights Agreement dated as of May 27, 1999 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors, Donaldson, Lufkin & Jenrette Securities Corporation, and Chase Securities Inc. (Exhibit

4.7 to our Registration Statement on Form S-4, filed on June 21, 1999, File Nos. 333-81143 through 333-81143-17). 4.B -- A/B Exchange Registration Rights Agreement dated as of May 17, 2001 between El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors listed on Schedule A thereto, Credit Suisse First Boston Corporation, Goldman, Sachs & Co., and J.P. Morgan Securities Inc. (Exhibit 4.3 to our Registration Statement on Form S-4, filed on June 25, 2001, Registration Nos. 333-63800 through 333-63800-20). 4.C -- Registration Rights Agreement dated as of August 28, 2000 by and between Crystal Gas Storage, Inc. and El Paso Energy Partners, L.P. (Exhibit 4.3 to our 2000 Form 10-K). 4.D -- Indenture dated as of May 27, 1999 among

El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors and Chase Bank of Texas, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4, filed on June 24, 1999, File Nos. 333-81143 through 333-81143-17); First Supplemental Indenture dated as of June 30, 1999 (Exhibit 4.2 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999 File Nos. 333-81143 through 333-81143-17); Second Supplemental Indenture dated as of July 27, 1999 (Exhibit 4.3 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999, File Nos. 333-81143 through 333-81143-17); Third Supplemental Indenture dated as of March 21, 2000, to the Indenture dated as of May 27, 1999, (Exhibit 4.7.1 to our 2000

Second Quarter Form 10-Q); Fourth Supplemental Indenture dated as of July 11, 2000. (Exhibit 4.2.1 to our 2001 Third Quarter Form 10-Q); Fifth Supplemental Indenture dated as of August 30, 2000 (Exhibit 4.2.2 to our 2001 Third Quarter Form 10-Q). 4.E -- Indenture dated as of May 11, 2000 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, The Subsidiary Guarantors named therein and The Chase Manhattan Bank, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4 filed June 25, 2001, Registration Nos. 333-63800 through 333-63800-20). 4.F -- Letter agreement dated March 5, 2002, between Crystal Gas Storage, Inc. and El Paso Energy Partners, LP. (Exhibit 4.F to our Annual Report on Form 10-K dated March 7, 2002).

EXHIBIT NUMBER DESCRIPTION - ------------------------

10.A -- First Amended and Restated Management Agreement, dated June 27, 1994 and effective as of July 1, 1992, between DeepTech International Inc. and the General Partner (Exhibit 10.1 to DeepTech's 1994 Form 10-K); First Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.76 to DeepTech's Registration Statement on Form S-1, filed on January 23, 1995, File No. 33-88688); Second Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.18 to our 1995 Form 10-K); Third Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.4 to our Registration Statement on Form S-4, filed on June 21, 1999, File No. 333-81143); Fourth Amendment to

First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.1 to our 1997 Second Quarter Form 10-Q); Fifth Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.1 our 1997 Third Quarter Form 10-Q); Sixth Amendment to First Amended and Restated Management Agreement between DeepTech International Inc. and the General Partner (Exhibit 10.2 to our 1998 Form 10-K).
10.B -- Fifth Amended and Restated Credit Agreement dated as of March 23, 1995, as amended and restated through May 16, 2001 by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, Credit Lyonnais New York Branch and First Union National Bank as Co-Syndication Agents, Fleet National Bank and Fortis Capital Corp., as Co-Documentation Agents, The Chase Manhattan Bank, as Administrative Agent, and

the several banks and other financial institutions signatories thereto. (Exhibit 10.2 to our 2001 Third Quarter Form 10-Q); First Amendment to Fifth Amended and Restated Credit Agreement dated as of October 10, 2001 (Exhibit 10.2.1 to our 2001 Third Quarter Form 10-Q). 10.C -- Credit Agreement dated as of August 23, 2000 by and among Argo, L.L.C., the lenders party thereto, the Chase Manhattan Bank, as administrative agent, First Union National Bank, as syndication agent, Bank One, N.A., as documentation agent, and Chase Securities Inc., as arranger (Exhibit 10.14 to our 2000 Third Quarter Form 10-Q). 10.D -- Sponsor Agreement dated as of August 23, 2000, by El Paso Energy Partners, L.P., and the Chase Manhattan Bank, as administrative agent (Exhibit 10.15 to our 2000 Third Quarter Form 10-Q). 10.E -- Redemption Agreement dated February 27, 1998 between Tatham Offshore, Inc. and

Flextrend Development Company, L.L.C., a subsidiary of El Paso Energy Partners, L.P. (Exhibit 10.1 our 1998 Third Quarter Form 10-Q). 10.F -- Farmout Agreement dated October 25, 1999 by and between Flextrend Development Company, L.L.C. and El Paso Production GOM, Inc. (Exhibit 10.15 to our Report on Form 8-K, filed on November 15, 1999). 10.G -- Limited Liability Company Agreement for Poseidon Oil Pipeline Company, L.L.C. dated February 14, 1996; First Amendment to the Limited Liability Company Agreement for Poseidon Oil Pipeline Company, L.L.C. dated February 14, 1996. (Exhibit 10.14 to our 2000 Second Quarter Form 10-Q). 10.H -- Fabrication Agreement dated as of July 16, 1999 by and between Delos Offshore Company and MODEC International LLC; Amendment No. 1 to the Fabrication Agreement dated as of August 31, 1999 by and between Delos Offshore Company and MODEC International

LLC. (Exhibit 10.20 to our 2000 Second Quarter Form 10-Q).

EXHIBIT NUMBER DESCRIPTION
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-- 10.I -- Purchase and Sale Agreement dated as of September 27, 2001 by and between American Natural Offshore Company, Texas Offshore Pipeline System, Inc., Unitex Offshore Transmission Company and ANR Western Gulf Holdings, L.L.C. as Sellers and El Paso Energy Partners Deepwater, L.L.C., as Buyer (Exhibit 2.1 to our Report on Form 8-K dated October 25, 2001). 10.J -- Assignment, Acceptance and Amendment dated October 4, 2001 by and between Delos Offshore Company, L.L.C., a Delaware limited liability company, The Chase Manhattan Bank, KBC Bank N.V., The Sumitomo Bank, Limited, Royal Bank of Canada, The Bank of New York, Societe Generale, Southwest Agency, Societe Generale Financial

Corporation, The Industrial Bank of Japan, Limited New York Branch, El Paso New Chaco Company, L.L.C., El Paso Natural Gas Company, El Paso Corporation, The Chase Manhattan Bank, in its capacity as Agent, and the State Street Bank and Trust Company, not in its individual capacity but solely as trustee for the Chaco Liquids Plant Trust (Exhibit 2.2 to our Report on Form 8-K dated October 25, 2001). 10.K -- Tolling Agreement dated as of October 1, 2001 between El Paso Field Services, L.P., and Delos Offshore Company, L.L.C. (Exhibit 2.3 to our Report on Form 8-K dated October 25, 2001). 10.L+ -- 1998 Unit Option Plan for Non-Employee Directors Amended and Restated effective as of April 18, 2001. (Exhibit 10.1 to our 2001 Second quarter Form 10-Q). 10.M+ -- 1998 Omnibus Compensation Plan, Amended and Restated, effective as of January 1, 1999 (Exhibit 10.9 to our 1998 Form 10-K); Amendment No. 1 dated as of December 1, 1999. (Exhibit 10.8.1 our 2000 Second Quarter Form 10-Q). 21. -- Subsidiaries of El Paso Energy Partners, L.P. (Exhibit 21. to our Annual Report on Form 10-K dated March 7, 2002). 23.A -- Consent of Independent Accountants. (Exhibit 23.A to our Annual Report on Form 10-K dated March 7, 2002). 23.B -- Consent of Independent Petroleum Engineers. (Exhibit 23.B to our Annual Report on Form 10-K dated March 7, 2002). *99.A -- Certification of the Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. *99.B -- Certification of the Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the

Sarbanes-
Oxley Act of
2002.

EXHIBIT 99.A

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K/A for the year ending December 31, 2001 of El Paso Energy Partners, L.P. (the "Company") as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert G. Phillips, Chief Executive Officer of El Paso Energy Partners Company, general partner of El Paso Energy Partners, L.P., certify (i) that the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ ROBERT G. PHILLIPS

Robert G. Phillips
Chief Executive Officer
El Paso Energy Partners Company, general
partner of El Paso Energy Partners, L.P.

January 2, 2003

EXHIBIT 99.B

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K/A for the year ending December 31, 2001 of El Paso Energy Partners, L.P. (the "Company") as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Keith B. Forman, Chief Financial Officer of El Paso Energy Partners Company, general partner of El Paso Energy Partners, L.P., certify (i) that the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ KEITH B. FORMAN

Keith B. Forman
Chief Financial Officer
El Paso Energy Partners Company, general
partner of El Paso Energy Partners, L.P.

January 2, 2003