AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON AUGUST 26, 1999

REGISTRATION NO. 333-

SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM S-1
REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933

LEVIATHAN GAS PIPELINE PARTNERS, L.P.
(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

DELAWARE	1311	76-0396023
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

BRITTON WHITE, JR.
EL PASO ENERGY BUILDING
1001 LOUISIANA STREET, 30(TH) FLOOR
HOUSTON, TEXAS 77002
(713) 420-2131
(Address, including zip code, and telephone number including area code of registrant's principal executive offices)

GRANT E. SIMS
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Approximate date of commencement of proposed sale of the securities to the public: As soon as practicable following the effectiveness of this registration statement.

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. [ ]

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. [ ] ____________________

If this form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective statement for the same offering. [ ] ____________________

If this form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. [ ] ____________________

If delivery of the prospectus is expected to be made pursuant to Rule 434, please check the following box. [ ]

CALCULATION OF REGISTRATION FEE

TITLE OF EACH CLASS OF SECURITIES TO BE REGISTERED	PROPOSED MAXIMUM AGGREGATE OFFERING PRICE(1)(2)	AMOUNT OF REGISTRATION FEE(2)
Common units representing limited partner interests	$112,125,000	$31,170.75

(1) Includes common units issuable upon underwriters' over-allotment.

(2) Estimated in accordance with Rule 457 solely for purposes of calculating the registration fee, based on the average high and low sale prices for the common units on the New York Stock Exchange on August 25, 1999.

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the registration statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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THE INFORMATION IN THIS PROSPECTUS IS NOT COMPLETE AND MAY BE CHANGED. WE MAY NOT SELL THESE SECURITIES UNTIL THE REGISTRATION STATEMENT FILED WITH THE SECURITIES AND EXCHANGE COMMISSION IS EFFECTIVE. THIS PROSPECTUS IS NOT AN OFFER TO SELL THESE SECURITIES AND IT IS NOT SOLICITING AN OFFER TO BUY THESE SECURITIES IN ANY STATE WHERE THE OFFER OR SALE IS NOT PERMITTED.

SUBJECT TO COMPLETION, DATED AUGUST 26, 1999

PROSPECTUS

4,000,000 COMMON UNITS

LEVIATHAN GAS PIPELINE PARTNERS, L.P.
REPRESENTING LIMITED PARTNER INTERESTS

$ PER UNIT

Leviathan Gas Pipeline Partners, L.P. is selling 4,000,000 common units. The underwriters named in this prospectus may purchase up to 600,000 additional common units from Leviathan under certain circumstances.

The common units are listed for trading on the New York Stock Exchange under the symbol "LEV". The last reported sale price of the common units on the New York Stock Exchange on August 25, 1999, was $23.875 per common unit.

INVESTING IN THE COMMON UNITS INVOLVES CERTAIN RISKS. LIMITED PARTNER INTERESTS ARE INHERENTLY DIFFERENT FROM CAPITAL STOCK OF A CORPORATION. SEE "RISK FACTORS" BEGINNING ON PAGE 14.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

	PER COMMON UNIT	TOTAL
Public Offering Price	$	$
Underwriting Discount	$	$
Proceeds to Leviathan (before expenses)	$	$

The underwriters are offering the units subject to various conditions. The underwriters expect to deliver the units to purchasers on or about , 1999.

SALOMON SMITH BARNEY
GOLDMAN, SACHS & CO.
PAINEWEBBER INCORPORATED
DAIN RAUSCHER WESSELS
A DIVISION OF DAIN
RAUSCHER INCORPORATED
FIRST UNION CAPITAL MARKETS CORP.

, 1999

[MAP]

YOU SHOULD RELY ONLY ON THE INFORMATION CONTAINED IN OR INCORPORATED BY REFERENCE IN THIS PROSPECTUS. WE HAVE NOT AUTHORIZED ANYONE TO PROVIDE YOU WITH DIFFERENT INFORMATION. LEVIATHAN IS NOT MAKING AN OFFER OF THESE SECURITIES IN ANY STATE WHERE THE OFFER IS NOT PERMITTED. YOU SHOULD NOT ASSUME THAT THE INFORMATION PROVIDED BY THIS PROSPECTUS IS ACCURATE AS OF ANY DATE OTHER THAN THE DATE ON THE FRONT OF THIS PROSPECTUS.

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FORWARD-LOOKING STATEMENTS AND OTHER INFORMATION

This prospectus includes and incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These statements relate to analyses and other information which are based on forecasts of future results and estimates of amounts not yet determinable. These statements also relate to our future prospects, developments and business strategies.

These forward-looking statements are identified by their use of terms and phrases such as "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "predict," "project," "will," and similar terms and phrases, including references to assumptions. These statements are contained in the sections entitled "Prospectus Summary," "Risk Factors," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and other sections of this prospectus and in the documents incorporated by reference in this prospectus.

These forward-looking statements involve risks and uncertainties that may cause our actual future activities and results of operations to be materially different from those suggested or described in this prospectus. These risks include the risks that are identified in this prospectus, which are primarily listed in the "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" sections. These risks may also be specifically described in our Annual Report on Form 10-K and Quarterly Reports on Form 10-Q and other documents we have filed with the Securities and Exchange Commission. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future or otherwise. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those expected, estimated or projected.

You should rely only on the information contained in this prospectus. We have not authorized anyone to provide you with different information. Leviathan is not making an offer of these securities in any state where the offer is not permitted. You should not assume that the information provided by this prospectus is accurate as of any date other than the date on the front of this prospectus.

You should not assume that the information in this document or any supplement is current as of any date other than the date on the front page of this prospectus. This document is not an offer to sell nor is it seeking an offer to buy these securities in any state or jurisdiction where the offer or sale is not permitted.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and special reports, proxy statements and other information with the Securities Exchange Commission under the Securities Exchange Act of 1934. You can inspect and/or copy these reports and other information at offices maintained by the SEC, including:

- the principal offices of the SEC located at Judiciary Plaza, 450 Fifth Street, N.W., Room 1024, Washington, D.C. 20549;

- the Regional Offices of the SEC located at Northwestern Atrium Center, 500 West Madison Street, Suite 1400, Chicago, Illinois 60661-2511;

- the Regional Offices of the SEC located at 7 World Trade Center, New York, New York 10048; and

- the SEC's website at http://www.sec.gov.

Further, our common units are listed on the New York Stock Exchange, and you can inspect similar information at the offices of the New York Stock Exchange, located at 20 Broad Street, New York, New York 10005.

PROSPECTUS SUMMARY

This prospectus summary highlights some basic information from this prospectus to help you understand the common units. It likely does not contain all the information that is important to you. You should read the entire prospectus carefully to understand fully the terms of the common units, as well as the tax and other considerations that are important to you in making your investment decision. You should pay special attention to the "Risk Factors" section beginning on page 14 of this prospectus to determine whether an investment in the common units is appropriate for you. For purposes of this prospectus, unless the context otherwise indicates, when we refer to "us," "we," "our," "ours," "Leviathan" or the "partnership," we are describing ourselves, Leviathan Gas Pipeline Partners, L.P., together with our subsidiaries.

THE OFFERING AND USE OF PROCEEDS

We are offering 4,000,000 common units by this prospectus, which will represent an aggregate 12.9% of the interest in the partnership. After this offering, our general partner and its affiliates will own an aggregate 30.3% interest in us, comprised of a 28.3% interest represented by 8,953,764 common units, a 1.0% interest represented by the sole general partner interest and a 1.0% interest represented by a non-managing membership interest in substantially all of our subsidiaries.

We plan to use the estimated $91.6 million of net proceeds from this offering to repay indebtedness under our revolving credit facility. Over the past 12 months, we have borrowed money under our revolving credit facility to fund certain of our pipeline and platform investments, including approximately $165.0 million to increase our ownership interest in several joint ventures and to fund certain capital expenditures. We may reborrow funds available under the revolving credit facility in the future to fund our portion of pipeline construction costs for our new Nemo joint venture; to construct a platform and other infrastructure facilities at our Ewing Bank 958 Unit oil and natural gas property; to construct and purchase pipelines, platforms and other hydrocarbon related facilities; and for general business purposes.

LEVIATHAN

WHO WE ARE

We are a publicly-traded Delaware limited partnership that provides integrated energy services, including natural gas and oil gathering, transportation, midstream and other related services in the U.S. Gulf of Mexico. Either directly or through joint ventures, we own interests in nine operating pipeline systems. These pipeline systems extend approximately 1,500 miles and have a design capacity of 6.8 billion cubic feet of natural gas and 400,000 barrels of oil per day. We also own interests in production handling, dehydration and other energy infrastructure facilities, multi-purpose platforms, and oil and natural gas properties. Our pipeline and infrastructure network currently extends from the shoreline, through the Flextrend (water depths of 600 to 1,500 feet) and up to and, in some places, into the Deepwater (water depths greater than 1,500 feet) in certain areas offshore Louisiana, Texas and Mississippi.

We believe our assets are well-positioned to maintain a stable base of operations and will continue to provide growth opportunities. These assets should allow us to compete for the transportation of new crude oil and natural gas production in our areas of service, especially those assets in the Flextrend and Deepwater regions. Either directly or through joint ventures, we own interests in offshore pipelines and related facilities, including:

- eight offshore natural gas pipeline systems;

- one offshore crude oil gathering system;

- six strategically-located, multi-purpose offshore platforms that serve to interconnect the pipeline grid;

- production handling and dehydration facilities; and

- four oil and natural gas properties associated with infrastructure opportunities.

In addition, we have recently completed the construction of a wholly owned oil pipeline which we expect to become operational in the fourth quarter of 1999 and, with our joint venture partners, we are constructing two natural gas gathering systems.

We conduct a large portion of our business through joint ventures and strategic alliances. We believe these arrangements are particularly well suited for Deepwater operations. We use joint ventures to reduce our capital requirements and risk exposure to individual projects, as well as to realize the benefits from combining resources with our joint venture partners. Our joint venture partners are generally integrated or very large independent energy companies with substantial interests, operations and assets in the Gulf of Mexico. Our current joint venture partners include affiliates of Coastal/ANR, Equilon, Marathon, Shell and Texaco.

Through our network of subsidiary and joint venture owned pipelines and other facilities and businesses, we believe we provide customers with an efficient and cost effective midstream alternative. We offer some customers a unique single point of contact through which they may access a wide range of integrated or independent midstream services, including gathering, transportation, production handling, dehydration and other services. We also provide producers operating in certain Deepwater and Flextrend areas with relatively low-cost access to numerous onshore long-haul pipelines and, accordingly, multiple end-use markets. Additionally, our Deepwater experience and specialized expertise in this area allows us to provide operational solutions to producers looking for economic improvements in their development activities.

OUR GENERAL PARTNER

El Paso Energy Corporation owns our sole general partner, Leviathan Gas Pipeline Company, whose primary assets are its ownership interests in us. El Paso Energy's strategy is to use us, when practical, as its primary growth vehicle for future offshore gathering and transportation activities in the Gulf of Mexico. El Paso Energy is a publicly-traded diversified energy holding company. It is engaged, through its subsidiaries, in the interstate and intrastate transportation, gathering and processing of natural gas; the marketing of natural gas, power and other commodities; power generation; and the development and operation of energy infrastructure facilities worldwide. For the year ended December 31, 1998, El Paso Energy reported operating revenues of approximately $5.8 billion and net income of approximately $225.0 million. El Paso Energy expects to complete its $6.0 billion acquisition of Sonat Inc., a diversified energy holding company, in late 1999. Sonat is engaged, through its subsidiaries and joint ventures, in domestic oil and natural gas exploration and production, the transmission and storage of natural gas, and natural gas and power marketing.

PROSPECTS FOR CONTINUED LONG-TERM GROWTH IN THE GULF OF MEXICO

We plan to focus our Gulf of Mexico operations on the more substantial properties being developed in the frontier regions of the Flextrend and Deepwater. Our pipeline and infrastructure network currently extends from the shoreline, through the Flextrend and up to and, in some areas, into the Deepwater. The location of some of our facilities in relation to properties currently being developed, as well as to the onshore long-haul pipelines which producers need in order to access the most attractive markets, should provide us with an economic advantage over some of our competitors. We believe more extensive Deepwater operations will permit us to enhance our financial stability and growth for many reasons, including the substantial reserves associated with Deepwater fields and the large capital commitments and longer-term view required by producers developing these regions. Accordingly, we believe that Deepwater projects are less sensitive to short term changes in natural gas and crude oil prices.

We believe that development and exploration activity in the Gulf of Mexico will continue and that it will continue to be one of the most prolific producing regions in the U.S. The Gulf of Mexico currently represents approximately 20.3% of total domestic production of oil and 25.6% of total domestic production of natural gas. Oil production from the Gulf of Mexico is expected to increase from 1.3 million barrels per day in 1998 to 1.8 million barrels per day in 2003, according to industry sources. Production of natural gas is also expected to increase from 14.0 billion cubic feet per day in 1998 to 16.6 billion cubic feet per day in 2003. The principal source of this growth is expected to be related to production in the Flextrend and Deepwater regions. Recent developments in oil and natural gas exploration and production techniques, such as 3-D seismic analysis, horizontal drilling, remote subsea completions via satellite templates and sea floor wellheads, and non-stationary surface production facilities, have substantially reduced finding, development and production costs, allowing operators to move into deeper hydrocarbon producing regions. By year-end 2003, production from deeper water fields is projected to account for 54.6% and 24.0% of the Gulf of Mexico's oil and natural gas production up from 35.6% and 13.4% in 1998.

We have pipelines, platforms and other infrastructure facilities strategically positioned throughout a large portion of the Flextrend area of the Gulf of Mexico, predominantly offshore Louisiana and Mississippi, extending out to and, in some cases, into the Deepwater. Because of their proximity to oil and natural gas development in the Gulf of Mexico, we expect these assets to play an important role in the development of oil and natural gas in surrounding areas of the Flextrend and Deepwater. We expect the development of new major discoveries, the extension of infrastructure and facilities and advances in exploration technology to result in additional development of the Flextrend and accelerate development of the Deepwater. A number of major discoveries in the Deepwater regions of the Gulf of Mexico have been announced by Shell, Exxon, BP Amoco, Unocal and other energy companies in recent years.

BUSINESS STRATEGY

Our business objective is to maintain and enhance our position as a provider of integrated energy services, to continue to enhance the quality of our cash flow, earnings and other financial results of operations and to provide additional growth opportunities by pursuing the following strategies:

- focus on high potential Deepwater operations, leveraging our existing assets and Deepwater expertise;

- provide independent, multiple market access for the Deepwater and Flextrend regions of the Gulf of Mexico;

- offer a single source alternative for a complete range of midstream services;

- diversify our portfolio with respect to geography, projects, customers and services;

- share capital costs and risks through joint ventures and strategic alliances, principally with partners with substantial financial resources and strategic interests in the Gulf of Mexico;

- design new infrastructure projects based on long-term commitments of dedicated production and/or fixed payments, with the ability to expand capacity and service in the future to capture potential growth opportunities; and

- selectively invest in oil and natural gas properties associated with infrastructure opportunities.

RECENT OPERATIONAL DEVELOPMENTS

WE FORMED A NEW NATURAL GAS DEEPWATER PIPELINE JOINT VENTURE WITH AN AFFILIATE OF SHELL. On August 10, 1999, we formed Nemo Gathering Company, LLC, a joint venture owned 66.1% by Tejas Offshore Pipeline, LLC, a subsidiary of Shell Oil Company, and 33.9% by us, to construct, own and operate a natural gas gathering system. The Nemo System will deliver natural gas production from the Shell-operated Brutus and Glider Deepwater development properties to another of our joint venture pipelines, the Manta Ray Offshore Gathering System. We expect the Nemo System to be placed in service in late 2001 at a total cost of approximately $36.0 million.

WE INCREASED OUR OWNERSHIP INTEREST IN THREE OF OUR EXISTING PIPELINE JOINT VENTURES--UTOS, HIOS AND EAST BREAKS, WHICH IS A NEW DEEPWATER EXPANSION. On June 30, 1999, we increased our ownership interest in three complementary, interconnecting natural gas pipeline systems located offshore Louisiana and the eastern portion of Texas. Through our acquisition of several companies from Natural Gas Pipeline

Company of America for approximately $51.0 million, we increased our ownership interest in the U-T Offshore System to 66.7% from 33.3%, the High Island Offshore System to 60.0% from 40.0%, and the East Breaks System to 60.0% from 40.0%. UTOS is a 30-mile pipeline extending from onshore Louisiana to a point of interconnection with HIOS, and receives substantially all of its throughput from HIOS for redelivery to an onshore production handling facility. HIOS is an expansive 204-mile pipeline system extending through the Flextrend and up to the Deepwater in our service areas. The East Breaks System is an 85-mile expansion currently under construction that will connect HIOS to the Diana and Hoover fields being developed by subsidiaries of Exxon and BP Amoco. Both Exxon and BP Amoco recently committed to the East Breaks System production from their Diana and Hoover properties. These two Deepwater properties are located in over 4,800 feet of water. With a throughput capacity of 400.0 million cubic feet per day of natural gas and the ability to expand its throughput capacity further, the East Breaks System and, therefore, the HIOS and UTOS systems have the ability to compete to gather and transport the substantial reserves associated with properties being, and expected to be, developed in these Deepwater frontier regions. We estimate that construction of the East Breaks System should be completed late in 2000 at a total cost of approximately $90.0 million.

WE ARE CONSTRUCTING A DEEPWATER PLATFORM IN CONNECTION WITH THE DEVELOPMENT OF OUR EWING BANK 958 UNIT. We believe our Ewing Bank 958 Unit development project, formerly known as the Sunday Silence Property, provides us with an opportunity to apply to the Deepwater area several strategies we have successfully implemented in the shallow and Flextrend areas. Similar to three other oil and natural gas properties we have developed, this project is associated with other independent infrastructure opportunities. Although the Ewing Bank 958 Unit development is a stand-alone project, we expect it to position us to play a significant role in the extension of pipeline, platform and other infrastructure facilities and service opportunities in this potential emerging Deepwater region. Currently, we anticipate building gathering extensions off of our Poseidon oil pipeline joint venture and our Manta Ray Offshore Gathering natural gas pipeline joint venture.

Pursuant to our current plan of development for the Ewing Bank 958 Unit, we are constructing a Moses Tension Leg Platform from which we would conduct all activities related to that development, including additional drilling, maintenance, and separation and handling operations. This platform is designed for use in water depths of up to 6,000 feet and will have production handling facilities with a throughput design capacity of 55.0 million cubic feet of natural gas per day and 25,000 barrels of oil per day.

To date there has been no production from the Ewing Bank 958 Unit. We currently own a 100% working interest in our Ewing Bank 958 Unit, which we purchased in October 1998 from a wholly owned, indirect subsidiary of El Paso Energy for $12.2 million. In addition to the initial discovery well drilled in 1994 and the two delineation wells drilled in 1994 and 1998, the Ewing Bank 958 Unit development program may require drilling up to five additional wells, depending on the level of actual production and other factors. As with many of our strategic assets, we continually evaluate various alternatives for the Ewing Bank 958 Unit and the related infrastructure to optimize the amount and quality of our cash flow. Given the size and nature of this project and the various strategic arrangements that might be available with a producer or another industry participant, we believe the Ewing Bank 958 Unit is well suited for a co-ownership, joint venture or other participatory arrangement. If we do not consummate such an arrangement, we may need to raise substantial amounts of additional capital to fund this development project.

WE HAVE CONSTRUCTED OUR ALLEGHENY OIL PIPELINE TO DELIVER CRUDE OIL FROM THE FLEXTREND AND DEEPWATER REGIONS TO OUR POSEIDON JOINT VENTURE. We recently completed construction of the Allegheny oil pipeline, a 100% owned, 40-mile long crude oil pipeline that will connect British Borneo's Allegheny Field in the Green Canyon area of the Gulf of Mexico with our Poseidon oil pipeline joint venture. British Borneo has committed to the Allegheny System production from its Allegheny Field. The Allegheny System, which will have a daily capacity of more than 80,000 barrels of oil per day, is scheduled to begin operating in the fourth quarter of 1999.

WE INCREASED OUR OWNERSHIP INTEREST IN OUR VIOSCA KNOLL JOINT VENTURE, A NATURAL GAS PIPELINE LOCATED PRIMARILY IN THE FLEXTREND WATERS. On June 1, 1999, we acquired an additional 49.0% interest in Viosca Knoll Gathering Company from a subsidiary of El Paso Energy, which resulted in us owning 99.0% of Viosca Knoll with an option to purchase the remaining 1.0%. We formed the Viosca Knoll joint venture in 1994 with a subsidiary of Tenneco Inc. to construct and operate a 125-mile long pipeline system, with an initial throughput capacity of 400.0 million cubic feet of natural gas per day, in an emerging producing region with limited infrastructure. The system design involved the construction of our first multi-purpose hub-platform and included the ability to expand throughput capacity at relatively nominal costs. Due to customer needs, including some recent Deepwater commitments, we have completed two expansion projects. These expansions more than doubled the Viosca Knoll System's capacity to 1.0 billion cubic feet per day. The Viosca Knoll System provides its customers access to interstate pipelines of, among others, El Paso Energy, Columbia Gulf Transmission Company, Sonat, Transco and Destin Pipeline Company.

STRUCTURE AND MANAGEMENT OF LEVIATHAN

Leviathan Gas Pipeline Company, our sole general partner and an indirect, wholly owned subsidiary of El Paso Energy, manages our activities and conducts our business. We and the general partner utilize the employees of, and management services provided by, El Paso Energy and its affiliates under a management agreement. Our principal executive office is located at the El Paso Energy Building, 1001 Louisiana Street, 26th Floor, Houston, Texas, 77002. Our telephone number is (713) 420-2131. The following chart depicts the ownership structure of Leviathan and certain of its affiliates after giving effect to the transactions described in this prospectus.

[CHART]

	OWNERSHIP		OWNERSHIP		OWNERSHIP
S Green Canyon	100.0%	S Viosca Knoll Block 817	100.0%	S Viosca Knoll Block 817	100.0%
S Tarpon	100.0%	S East Cameron Block 373	100.0%	S Ewing Bank 958 Unit	100.0%
S Viosca Knoll	99.0%(3)	S Ship Shoal Block 332	100.0%	S Garden Banks Block 72	50.0%
S UTOS	66.7%	S South Timbalier Block 292	100.0%	S Garden Banks Block 117	50.0%
S HIOS	60.0%	S Ship Shoal Block 331	100.0%	S West Delta Block 35	38.8%
S East Breaks	60.0%	S Garden Banks Block 72	50.0%		
S Stingray	50.0%	S West Cameron Dehy	50.0%		
S Nemo	33.9%				
S Manta Ray Offshore	25.7%				
S Nautilus	25.7%				
S Allegheny	100.0%				
S Poseidon	36.0%				

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(1) Represents ownership interest after giving effect to the offering, assuming the underwriters do not exercise their over-allotment option. Prior to the consummation of this offering, El Paso Energy has a 34.5% effective interest in us.

(2) Leviathan Gas Pipeline Company, a wholly owned subsidiary of El Paso Energy, is our general partner. El Paso Energy's 30.3% effective interest in us, which is held by our general partner and its affiliates, includes a 1.0% general partner interest, a 28.3% limited partner interest comprised of 8,953,764 common units, and a 1.0% non-managing member interest in substantially all of our subsidiaries.

(3) The remaining 1.0% interest in Viosca Knoll is held by El Paso Energy. We have an option to acquire this remaining 1.0% from El Paso Energy, exercisable after June 1, 2000.

THE OFFERING

Common units offered....... 4,000,000 common units

4,600,000 common units if the underwriters exercise in full their over-allotment option.

Units to be outstanding after the offering.................

	Number of Units	Percent of Total
Common units.........................	30,737,465	99.1%
Preference units....................	291,299	0.9%
	31,028,764	100.0%

If the underwriters exercise in full their over-allotment option, we will issue an additional 600,000 common units, which will result in 31,337,465 common units outstanding representing a 99.1% interest and 291,299 preference units outstanding representing a 0.9% interest.

To satisfy its obligation under our partnership agreement to maintain a 1.0% general partner interest, our general partner will contribute approximately $925,000 in cash to us upon the consummation of this offering, approximately $1,065,000 in cash if the underwriters exercise in full their over-allotment option.

Use of proceeds............ We plan to use the proceeds from this offering to repay indebtedness under our revolving credit facility. Over the past 12 months, we have borrowed money under our revolving credit facility to fund certain of our pipeline and platform investments, including approximately $165.0 million to increase our ownership interest in several joint ventures and to fund certain capital expenditures. We may reborrow funds available under the revolving credit facility in the future to fund our portion of pipeline construction costs for our new Nemo joint venture; to construct a platform and other infrastructure facilities at our Ewing Bank 958 Unit oil and natural gas property; to construct and purchase pipelines, platforms and other hydrocarbon related facilities; and for general business purposes.

New York Stock Exchange symbol................... LEV

Distributions of available cash..................... Our partnership agreement requires us to distribute, within 45 days after the end of each calendar quarter, all of our "available cash, "as such term is defined in our partnership agreement. Generally, "available cash" means, for the applicable quarter, all cash receipts for such quarter and any reductions in reserves established in prior quarters less all cash disbursements made in such quarter and additions to reserves, as determined by our general partner.

Except to the extent our general partner has earned the right to receive any incentive distributions, we will distribute 98.0% of our available cash constituting cash from operations to our limited partners in respect of their common units and preference units and 2.0% of such available cash to our general partner in respect of its 1.0% general partner interest and its 1.0% non-managing member interest.

Senior, subordinated, non-cumulative distribution rights...... The common unit distribution rights with respect to available cash constituting cash from operations (1) are subordinate to the right of preference units to receive the minimum quarterly distribution amount of $0.275 per preference unit, $1.10 annually per preference unit, including arrearages, and (2) until the common units receive an amount, excluding arrearages, equal to the minimum quarterly distribution amount, are senior to the right of any other unit to receive a share of distributions of available cash constituting cash from operations.

After the holders of our preference units have received distributions of available cash constituting cash from operations during any relevant quarter equal to the minimum quarterly distribution amount plus any arrearages, but before any other units may participate in distributions of such available cash during such quarter, the holders of our common units are entitled to receive during such quarter distributions of such available cash, if any, in an amount up to the minimum quarterly distribution amount. However, our common units do not have cumulative distribution participation rights, and arrearages do not accrue on the common units for any shortfall in the minimum quarterly distribution amount.

Fully participating distribution rights........ The holders of our common units are entitled to fully participate in quarterly distributions of available cash constituting cash from operations, subject to the right of our general partner to receive its regular distribution of 2.0% and any incentive distributions described below, the right of holders of our preference units to receive minimum quarterly distributions and any arrearages, and the right of holders of any securities we issue after this offering to receive any priority distributions attributable to such securities. The holders of our preference units do not have the right to participate in distributions of available cash constituting cash from operations in excess of the minimum quarterly distribution amount plus arrearages, if any.

General partner incentive distributions............ The following table illustrates the percentage allocation of distributions of available cash among the unitholders and our general partner up to the various target distribution levels.

	QUARTERLY DISTRIBUTION AMOUNT PER UNIT UP TO	PERCENT OF MARGINAL AVAILABLE CASH DISTRIBUTED TO	
		COMMON UNITHOLDERS	GENERAL PARTNER
Minimum Quarterly Distribution	$0.275	98%	2%
First Target Distribution	0.325	98%	2%
Second Target Distribution	0.375	85%	15%
Third Target Distribution	0.425	75%	25%
Thereafter	--	50%	50%

Adjustments to minimum quarterly and target distribution amounts..... The minimum quarterly distributions and the specified target levels relating to incentive distributions may be adjusted under certain circumstances in accordance with our partnership agreement.

Interim capital transactions distributions and liquidating distributions............	Because of their unique nature, our partnership agreement specially allocates among our partners distributions of available cash constituting cash from "interim capital transactions" and distributions made in connection with our termination and the liquidation of our assets and businesses. For a detailed explanation, see the section in this prospectus entitled "Description of Common Units" beginning on page 81.
Subsequent issuances.......	We have the ability to issue an unlimited number of additional securities from time to time, which may have rights equal or superior to the rights of our outstanding units.
Lack of dissenter's rights or preemptive rights.....	Holders of common units do not have dissenters' rights of appraisal in the event of a merger or consolidation of the partnership or a sale of substantially all of its assets or preemptive rights.
Limited call right.........	If, at any time, non-affiliates of our general partner own 15.0% or less of the issued and outstanding units of any class (including common units), then our general partner may call, or assign to us or its affiliates our right to call, such remaining publicly-held units at a market-based price.
Voting Rights..............	Our general partner manages and operates our business. Unlike the holders of common stock in a corporation, you will have only very limited voting rights on matters affecting our business. You will have no right to elect our general partner on an annual or other continuing basis.
Restrictions on transfers of units.................	Purchases, sales and other transfers of our units will be effective only if they comply with the requirements of our partnership agreement, including the requirements that the transferee be an eligible U.S. person, make certain representations and warranties and become a party to our partnership agreement.

Information contained in "The Offering" section of this prospectus is a summary and should be read in conjunction with the rest of this prospectus, including the sections entitled "Description of Common Units" beginning on page 81 and "Certain Other Partnership Agreement Provisions" beginning on page 90.

TAX CONSIDERATIONS

The tax consequences to you of an investment in units will depend in part on your own tax circumstances. For a discussion of the principal federal income tax considerations associated with our operations and the purchase, ownership and disposition of units, see "Income Tax Considerations" beginning on page 95. You should consult your own tax advisor about the federal, state, local and foreign tax consequences peculiar to your circumstances.

We estimate that if you purchase a unit in this offering and hold the unit through the record date for the distribution with respect to the final calendar quarter of 2001 (assuming quarterly distributions on the units with respect to that period are equal to the current quarterly distribution rate of $0.525 per unit), you will be allocated an amount of federal taxable income for that period that is less than or equal to approximately 30% of the amount of cash distributed to you with respect to that period.

This estimate is based upon many assumptions regarding our business and operations, including assumptions as to tariffs, capital expenditures, cash flows and anticipated cash distributions. This estimate and the assumptions are subject to, among other things, numerous business, economic, regulatory and competitive uncertainties beyond our control and to certain tax reporting positions that we have adopted. The Internal Revenue Service could disagree with our tax reporting positions, including estimates of the relative fair market values of our assets and the validity of curative allocations. Accordingly, we cannot assure you that the estimate will be correct. The actual percentage of distributions that will constitute taxable income could be higher or lower, and any differences could be material.

RISK FACTORS

You should carefully consider the discussion of risks beginning on page 14 and the other information included in this prospectus prior to investing in our common units. Some of the risks discussed include:

- You will have limited voting rights and will not control our general partner.

- We may issue additional units, diluting your interests.

- Our ability to distribute cash to you depends on factors out of our control, including the rates for, and volume of, production that we handle, and on successful exploration and development of additional oil and natural gas reserves.

- Our substantial indebtedness could adversely affect our financial condition, prevent us from making distributions to you and restrict our ability to operate.

- Our actual project costs could exceed our forecast, and our cash flow from projects may not be immediate.

- The interruption of distributions to us from our subsidiaries and joint ventures may affect our ability to make cash distributions to you.

- Federal Energy Regulatory Commission regulation and a changing regulatory environment could affect our cash flow and, accordingly, distributions.

- The Year 2000 date change may result in decreased revenues for us.

- El Paso Energy and its affiliates may have conflicts of interest with us and, accordingly, you.

- Our partnership agreement purports to limit our general partner's fiduciary duties and certain other obligations relating to us.

- We cannot cause our joint ventures to take or not to take certain actions unless some or all of our joint venture partners agree.

- If we proceed with the development of our Ewing Bank 958 Unit without a partner who will share a significant portion of the costs, we will require more capital than is currently available from our existing sources.

- We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

- A change of control of our general partner may adversely affect you.

- We have not received a ruling or assurances from the IRS on any matters affecting us.

- Our tax treatment depends on our partnership status.

- We can only deduct certain losses.

- Your tax liability resulting from an investment in our units could exceed any cash you receive as a distribution from us or the proceeds from dispositions of those units.

SUMMARY HISTORICAL AND PRO FORMA CONSOLIDATED FINANCIAL DATA

The historical financial data for each of the three years ended December 31, 1996, 1997 and 1998, and as of December 31, 1997 and 1998 was derived from our consolidated financial statements and notes thereto included elsewhere in this prospectus. The historical financial data as of December 31, 1996 has been derived from our historical consolidated financial statements (not included herein). The historical financial data for each of the six months ended June 30, 1998 and 1999 and as of June 30, 1999 was derived from our unaudited consolidated financial statements and notes thereto included elsewhere in this prospectus. The historical financial data as of June 30, 1998 has been derived from our unaudited historical consolidated financial statements (not included herein). We believe that all material adjustments, consisting only of normal recurring adjustments necessary for the fair presentation of our interim results, have been included. Results of operations for any interim period are not necessarily indicative of the results of operations for the entire year due to the seasonal nature of our business. The unaudited pro forma consolidated financial data reflects (1) the issuance of 4,000,000 common units pursuant to this offering, (2) the consummation of the UTOS/HIOS/East Breaks acquisition, (3) the issuance of our subordinated notes, (4) the consummation of the Viosca Knoll transaction, (5) the repayment and cancellation of Viosca Knoll's credit facility, (6) the reduction of our revolving credit facility, and (7) the payment and amortization of transaction costs. The unaudited pro forma consolidated financial data is based on the assumptions described in the notes to the unaudited pro forma consolidated financial statements located on pages F-3 through F-10 and is not necessarily indicative of the results of operations that may be achieved in the future. You should read this information along with "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 32, "Business and Properties" beginning on page 45 and the consolidated financial statements and notes thereto listed on pages F-1 and F-2.

	YEAR ENDED DECEMBER 31,			PRO FORMA YEAR ENDED DECEMBER 31,	SIX MONTHS ENDED JUNE 30,		PRO FORMA SIX MONTHS ENDED
	1996	1997	1998	1998	1998	1999	JUNE 30, 1999
				(UNAUDITED)	(UNAUDITED)		(UNAUDITED)
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)						
STATEMENT OF OPERATIONS:							
Oil and natural gas sales.................	$ 47,068	$ 58,106	$ 31,411	$ 31,939	$ 15,734	$ 15,100	$ 15,141
Gathering, transportation and platform services.....	24,005	17,329	17,320	47,415	7,782	10,798	23,740
Equity in earnings......	20,434	29,327	26,724	21,048	12,571	19,953	17,404
Total revenue.....	91,507	104,762	75,455	100,402	36,087	45,851	56,285
Operating expenses......	9,068	11,352	11,369	14,595	5,546	5,025	6,061
Depreciation, depletion and amortization......	31,731	46,289	29,267	34,797	14,845	13,727	16,315
Impairment, abandonment and other.............	--	21,222	(1,131)	(1,131)	--	--	--
General and administrative expenses and management fee........	8,540	14,661	16,189	16,343	7,503	5,909	5,972
Total operating costs..........	49,339	93,524	55,694	64,604	27,894	24,661	28,348
Operating income........	42,168	11,238	19,761	35,798	8,193	21,190	27,937
Interest income and other.................	1,710	1,475	771	1,821	157	268	799
Interest and other financing costs.......	(5,560)	(14,169)	(20,242)	(29,212)	(8,429)	(13,868)	(17,336)
Minority interest in (income) loss.........	(427)	7	(15)	(321)	(3)	(80)	(216)
Income (loss) before income taxes..........	37,891	(1,449)	275	8,086	(82)	7,510	11,184

	YEAR ENDED DECEMBER 31, 1996	1997	1998	PRO FORMA YEAR ENDED DECEMBER 31, 1998	SIX MONTHS ENDED JUNE 30, 1998	1999	PRO FORMA SIX MONTHS ENDED JUNE 30, 1999
				(UNAUDITED)	(UNAUDITED)		(UNAUDITED)
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)						
Income tax benefit......	801	311	471	471	168	177	177
Net income (loss).........	$ 38,692	$ (1,138)	$ 746	$ 8,557	$ 86	$ 7,687	$ 11,361
Basic and diluted net income (loss) per unit..................	$ 1.57	$ (0.06)	$ 0.02	$ 0.22	$ 0.00	$ 0.25	$ 0.30
CASH DISTRIBUTIONS DECLARED PER UNIT:							
Preference unit.........	$ 1.45	$ 1.85	$ 1.60	$ 1.60	$ 1.05	$ 0.55	$ 0.55
Common unit............	$ 1.45	$ 1.85	$ 2.10	$ 2.10	$ 1.05	$ 1.05	$ 1.05
BALANCE SHEET DATA (AT END OF PERIOD):							
Total assets...........	$453,526	$409,842	$442,726	(1)	$406,087	$625,913	$625,913
Total debt.............	227,000	238,000	338,000	(1)	270,000	481,500	388,975
Partners' capital.......	192,023	143,966	82,896	(1)	113,557	120,036	212,561
OTHER FINANCIAL DATA:							
EBITDA(2)...............	$ 73,899	$ 78,749	$ 47,897	$ 69,464	$ 23,038	$ 34,917	$ 44,252
Adjusted EBITDA(3)......	90,288	76,557	52,344	74,790	23,765	39,072	47,039
Net cash provided by operating activities...........	50,179	67,485	25,677	(1)	12,884	23,640	(1)
Net cash used in investing activities...........	101,721	41,769	65,624	(1)	19,366	92,818	(1)
Net cash provided by (used in) financing activities...........	52,525	(35,775)	36,625	(1)	1,194	69,371	(1)
Capital expenditures included in investing activities...........	101,721	41,957	66,111	(1)	19,366	92,818	(1)

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(1) This information is not included in this table as it is not required.
(2) EBITDA is defined for this purpose as operating income before depreciation, depletion and amortization and impairment, abandonment and other. EBITDA is used as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to net income, as an indicator of our operating performance or as an alternative to cash flows from operating activities as a measure of liquidity. EBITDA may not be a comparable measurement among different companies. EBITDA is presented here to provide additional information about us.
(3) Adjusted EBITDA is defined for this purpose as EBITDA plus cash distributions from equity investments less earnings attributable to equity investments. We believe Adjusted EBITDA is a meaningful disclosure because of the significance of our equity investments. Adjusted EBITDA is used as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to net income, as an indicator of our operating performance or as an alternative to cash flows from operating activities as a measure of liquidity. Adjusted EBITDA may not be a comparable measurement among different companies. Adjusted EBITDA is presented here to provide additional information about us.

RISK FACTORS

LIMITED PARTNER INTERESTS ARE INHERENTLY DIFFERENT FROM CAPITAL STOCK OF A CORPORATION, ALTHOUGH MANY OF THE BUSINESS RISKS TO WHICH WE ARE SUBJECT ARE SIMILAR TO THOSE THAT WOULD BE FACED BY A CORPORATION ENGAGED IN THE SAME BUSINESS. YOU SHOULD CAREFULLY CONSIDER THE FOLLOWING FACTORS BEFORE INVESTING IN COMMON UNITS.

This prospectus includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 including, in particular, the statements about our plans, strategies and prospects under the headings "Prospectus Summary," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Business." Although we believe that our plans, intentions and expectations reflected in or suggested by such forward-looking statements are reasonable, we cannot assure you that we will achieve such plans, intentions or expectations. Important factors that could cause actual results to differ materially from the forward-looking statements we make in this prospectus are set forth below and elsewhere in this prospectus. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the following cautionary statements.

RISKS INHERENT IN AN INVESTMENT IN OUR COMMON UNITS

YOU WILL HAVE LIMITED VOTING RIGHTS AND WILL NOT CONTROL OUR GENERAL PARTNER.

Unlike the holder of capital stock in a corporation, you only have limited voting rights on matters affecting our business. Our general partner, whose directors you do not elect, manages our activities. You will have no right to elect the general partner on an annual or any other continuing basis. If the general partner voluntarily withdraws, however, the holders of a majority of the outstanding units (excluding for purposes of such determination units owned by the withdrawing general partner and its affiliates) may elect its successor.

The general partner may not be removed as our general partner except upon approval by the affirmative vote of the holders of at least 55% of the outstanding units (including units owned by the general partner and its affiliates), subject to the satisfaction of certain conditions. Any removal of the general partner is not effective until the holders of a majority of the outstanding units approve a successor general partner. Before the holders of outstanding units may remove the general partner, they must receive an opinion of counsel that:

- such action will not result in the loss of limited liability of any limited partner or of any member of any of our subsidiaries or cause us or any of our subsidiaries to be taxable as a corporation or to be treated as an association taxable as a corporation for federal income tax purposes; and

- all required consents by any regulatory authorities have been obtained.

The general partner has agreed not to withdraw voluntarily as our general partner on or before December 31, 2002 (with limited exceptions), unless the holders of at least a majority of the outstanding units (excluding units owned by the general partner and its affiliates) approve the withdrawal. The withdrawal or removal of the general partner as general partner of the partnership would effectively result in its concurrent withdrawal or removal as the manager of our subsidiaries.

WE MAY ISSUE ADDITIONAL UNITS, DILUTING YOUR INTERESTS.

We can issue additional limited partner interests and other equity securities, including equity securities with rights to distributions and allocations or in liquidation equal or superior to the common units, for any amount and on any terms and conditions established by the general partner. If we issue more units or other equity securities, it will reduce your proportionate ownership interest in us. This could cause the market price of your units to fall and reduce the cash distributions paid to you as a common unitholder. Further, we have the ability to issue partnership interests with voting rights superior to yours. If we issued any such securities, it could adversely affect your already limited voting power.

YOU MAY NOT HAVE LIMITED LIABILITY IN THE CIRCUMSTANCES DESCRIBED BELOW AND MAY BE LIABLE FOR THE RETURN OF WRONGFUL DISTRIBUTIONS.

You will not be liable for assessments in addition to your initial capital investment in the common units. However, you may be required to repay to us amounts wrongfully returned or distributed to you under some circumstances. Under Delaware law, a limited partnership may not make a distribution to a partner to the extent that at the time of the distribution, after giving effect to the distribution, all liabilities of the partnership (other than liabilities to partners on account of their partnership interests and nonrecourse liabilities) exceed the fair value of the assets of the limited partnership. Delaware law provides that a limited partner who receives such a distribution and knew at the time of the distribution that the distribution violated the law will be liable to the limited partnership for the amount of the distribution for three years from the date of the distribution. Under Delaware law, an assignee who becomes a substitute limited partner of a limited partnership is liable for the obligations of his assignor to make contributions to the partnership, except the assignee is not obligated for liabilities that were unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

Our limited partners have the right to take certain limited actions, including the removal of the general partner, under our partnership agreement. If it were determined under Delaware law such actions constituted "control" of our business, then you could be held personally liable for our obligations to the same extent as the general partner.

COMMON UNITS ARE SUBJECT TO RESTRICTIONS ON TRANSFER.

All purchasers of common units who wish to become unitholders of record must deliver an executed transfer application in which the purchaser or transferee must certify that, among other things, he, she or it is eligible to purchase the units before the purchaser or transferee of the units will be registered on our records and before cash distributions can be made and federal income tax information furnished to the purchaser or transferee. A person purchasing units who does not execute a transfer application and certify that the purchaser is eligible to purchase the units acquires no rights in the units other than the right to resell the units. Further, our general partner may request each record holder of a unit to furnish certain information about the holder's nationality, citizenship or other related status. If the record holder fails to furnish the information or if the general partner determines, on the basis of the information furnished by the holder in response to the request, that the cancellation or forfeiture of any property in which we have an interest may occur, the general partner may be substituted as a unitholder for the record holder, who will then be treated as a non-citizen assignee, and we will have the right to redeem the units held by the record holder. As a result of these restrictions, your ability to transfer your units may be adversely affected. See "Description of Common Units--Transfer of Units."

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

If at any time our general partner and its affiliates hold 85% or more of the issued and outstanding common units, the general partner will have the right to purchase all, but not less than all, of the outstanding common units held by nonaffiliates. This purchase would take place as of a record date which would be selected by the general partner, on at least 30 but not more than 60 days' notice. The general partner may assign and transfer this call right to any of its affiliates or to us. If the general partner (or its assignee) exercises this call right, it must purchase the common units at the higher of (1) the highest cash price paid by the general partner or its affiliates for any common unit purchased within the 90 days preceding the date the general partner mails notice of the election to call the common units or (2) the average of the last reported sales price per common unit over the 20 trading days preceding the date five days before the general partner mails such notice. Accordingly, under certain circumstances you may be required to sell your common units against your will and the price you receive for those common units may be less than you would like to receive. Upon consummation of this offering, our general partner and its affiliates will hold an effective 30.3% interest in us.

RISKS RELATED TO OUR BUSINESS

OUR ABILITY TO DISTRIBUTE CASH TO YOU DEPENDS ON FACTORS OUT OF OUR CONTROL, INCLUDING THE RATES FOR, AND VOLUME OF, PRODUCTION THAT WE HANDLE.

We do not guarantee that we will make cash distributions to you. Our ability to make cash distributions, as well as our ability to make payments on our indebtedness and to fund future working capital, capital expenditures and other general corporate requirements will depend on our ability to generate cash in the future. This, to a certain extent, is subject to economic, financial, competitive, legislative, regulatory and other factors that are beyond our control.

Our future performance and, therefore, our ability to make cash distributions, will largely depend on the volume of, and rates for, the natural gas and oil handled by our pipelines, platforms and other infrastructure. Many factors outside of our control can affect these volumes and rates. The following factors, among others, affect the rates that our pipelines may charge:

- commodity prices for the production handled;

- competition from other pipelines; and

- the maximum rates established by the FERC for our regulated pipelines.

Any decrease in the rates charged or volumes handled by any of our pipelines and other facilities could reduce our available cash. Accordingly, we cannot assure you that we will be able to continue to generate enough cash flow to satisfy our existing commitments and make cash distributions to you.

Based on our current and anticipated level of operations and revenue growth, we believe our cash flow from operations, available cash and available borrowings under our revolving credit facility will be adequate to conduct our businesses as they currently exist and make cash distributions at our current rate for the foreseeable future. We cannot assure you, however, that these or other sources of capital will be available to us in amounts sufficient to enable us to pay our indebtedness or to fund our other liquidity needs, including the purchase, construction or other acquisition of assets or businesses in the future, let alone make cash distributions to you.

IF WE PROCEED WITH THE DEVELOPMENT OF OUR EWING BANK 958 UNIT WITHOUT A PARTNER WHO WILL SHARE A SIGNIFICANT PORTION OF THE COSTS, WE WILL REQUIRE MORE CAPITAL THAN IS CURRENTLY AVAILABLE FROM OUR EXISTING SOURCES.

The development plan we filed with the U.S. Department of Interior Minerals Management Service ("MMS") estimates that it will cost approximately $100.0 million in drilling costs, including amounts to drill, complete and tie-back the producing wells, and $150.0 million in infrastructure costs, including amounts to design, construct and install the producing platform and export pipelines. These estimates are inherently uncertain, and the drilling costs in particular could exceed materially our forecast because of the uncertainties and difficulties associated with Deepwater drilling operations.

We currently do not have, and may not be able to obtain, the capital required to undertake 100% of the development of our Ewing Bank 958 Unit and the related infrastructure. While we expect to have a partner in this project pursuant to an exchange, sale, farmout, joint venture or similar arrangement, we cannot assure you that we will be successful in structuring such an arrangement. If no such arrangement exists, we will have to raise additional capital through another source or we will not be able to proceed with this development as currently planned. We cannot assure you that any such source of capital would be available to complete this project or that this project will be completed as contemplated, if at all.

OUR FUTURE PERFORMANCE, AND THUS OUR ABILITY TO MAKE CASH DISTRIBUTIONS, DEPENDS ON SUCCESSFUL EXPLORATION AND DEVELOPMENT OF ADDITIONAL OIL AND NATURAL GAS RESERVES.

The natural gas and oil reserves available to our pipelines and other infrastructure from existing wells naturally decline over time. In order to offset this natural decline, our pipelines and other infrastructure must access additional reserves. This means that our long-term prospects depend upon the successful exploration and development of additional reserves by third parties in areas accessible to our pipelines and other infrastructure.

Finding and developing new natural gas and oil reserves from offshore properties is very expensive. The Flextrend and Deepwater areas, especially, will require large capital expenditures by third party producers for exploration, development drilling, installation of production facilities and pipeline extensions to reach the new wells.

Many economic and business factors out of our control can adversely affect the decision by any third party producer to explore for and develop new reserves. These factors include relatively low natural gas and oil prices, cost and availability of equipment, capital budget limitations or the lack of available capital. For example, because of the decline in hydrocarbon prices during 1998 and the first quarter of 1999, the level of overall oil and natural gas activity in the Gulf of Mexico has declined from recent years. If hydrocarbon prices decline again or capital spending by the energy industry continues to decrease or remains at low levels for prolonged periods, our results of operations and cash flow could suffer. Consequently, we cannot assure you that additional reserves will be discovered or developed in the near future, or that they exist at all.

PRICE AND VOLUME VOLATILITY IS SUBSTANTIALLY OUT OF OUR CONTROL AND IT COULD HAVE AN ADVERSE AFFECT ON OUR PRODUCTION BUSINESS.

Our business and, to a certain extent, our ability to make cash distributions will be substantially affected by our future production from our oil and natural gas properties. The level of success of our future production from such properties is largely dependent on factors out of our control, such as the volume of, and prices realized for, the natural gas and oil produced from our oil and natural gas properties. In 1998, oil and natural gas prices dramatically declined, and although prices have increased in 1999, we cannot assure you that there will not be further declines in commodity prices. Based on 1998 production levels of our currently producing properties which are depleting assets, for every $0.10 decline in the average price for natural gas and every $1.00 decline in the average price for oil we actually realized, our cash flow from operations would be reduced by $1.1 million and $0.5 million, respectively.

OUR SUBSTANTIAL INDEBTEDNESS COULD ADVERSELY AFFECT OUR FINANCIAL CONDITION AND PREVENT US FROM MAKING DISTRIBUTIONS TO YOU.

We have a significant amount of indebtedness and the ability to incur more indebtedness. In May 1999, we issued $175.0 million of 10 3/8% senior subordinated notes due in 2009, which are supported by guarantees of our subsidiaries. We are also party to a $375.0 million revolving credit facility, which is collateralized by a pledge of the equity of our subsidiaries and supported by guarantees of our subsidiaries. As of August 9, 1999, we had $300.0 million outstanding under this revolving credit facility and would have been permitted to borrow up to an additional $44.5 million. Our substantial indebtedness could have important consequences to you. For example, it could:

- increase our vulnerability to general adverse economic and industry conditions;

- limit our ability to make distributions to you, or to fund future working capital, capital expenditures and other general partnership requirements, future acquisition, construction or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness;

- limit our flexibility in planning for, or reacting to, changes in our businesses and the industries in which we operate; and

- place us at a competitive disadvantage as compared to our competitors that have less debt.

OUR INDEBTEDNESS MAY RESTRICT OUR ABILITY TO OPERATE.

We must comply with various affirmative and negative covenants contained in the indenture related to our senior subordinated notes and our revolving credit facility, which is secured by substantially all of our assets. Among other things, these covenants limit our ability to:

- incur additional indebtedness or liens;
- make payments in respect of or redeem or acquire any debt or equity issued by us;
- sell assets;
- make loans or investments;
- acquire or be acquired by other companies; and
- amend certain contractual arrangements.

The restrictions under our indebtedness may prevent us from engaging in certain transactions which might otherwise be considered beneficial to us. Our indebtedness also requires us to make mandatory repayments under certain circumstances, including when we sell certain assets, fail to achieve or maintain certain financial targets or experience a change in control. In addition, we cannot prepay the balance outstanding under our senior subordinated notes without incurring substantial penalties.

If we incur additional indebtedness in the future, it would be under our existing credit agreement or under arrangements which, we believe, would have terms and conditions at least as restrictive as those contained in our existing credit agreement. Failure to comply with the terms and conditions of any existing or future indebtedness would constitute an event of default. If an event of default occurs, the lenders will have the right to accelerate the maturity of such indebtedness and foreclose upon the collateral, if any, securing that indebtedness. Such an event could limit our ability to make cash distributions to you, and could affect the market price of the common units.

WE WILL FACE COMPETITION FROM THIRD PARTIES TO HANDLE ANY NEW PRODUCTION.

Even if additional reserves exist in the areas accessed by our pipelines and are ultimately produced, we cannot assure you that any of these reserves will be gathered, transported, processed or otherwise handled by any of our pipelines and other infrastructure. We would compete with others, including producers of oil and natural gas, for any such production on the basis of many factors, including:

- geographic proximity to the production;
- costs of connection;
- available capacity;
- rates; and
- access to onshore markets.

POTENTIAL FUTURE EXPANSIONS MAY ADVERSELY AFFECT OUR BUSINESS BY SUBSTANTIALLY INCREASING THE LEVEL OF OUR INDEBTEDNESS AND CONTINGENT LIABILITIES AND INCREASING OUR RISKS OF BEING UNABLE TO EFFECTIVELY INTEGRATE THESE NEW OPERATIONS.

We intend to continue to construct and purchase assets, including entire businesses, that we believe will present opportunities to realize synergies, expand our role in the energy infrastructure business and/or increase our market position. This strategy may require substantial capital, and we may not be able to raise the necessary funds on satisfactory terms or at all.

We regularly engage in discussions with respect to potential acquisition and investment opportunities. If we consummate any future acquisitions, our capitalization and results of operations may change significantly and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds.

We are currently considering some specific future acquisitions or investments, although we cannot assure you that we will be able to reach agreement with respect to any of these opportunities. If consummated, any acquisition would likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and amortization expenses related to goodwill and other intangible assets, which could have a material adverse effect upon our business.

Acquisitions and business expansions involve numerous risks, including difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments and the diversion of management's attention from other business concerns. For all of these reasons, if any acquisitions or expansions occur, our business could be adversely affected.

OUR ACTUAL PROJECT COSTS COULD EXCEED OUR FORECAST, AND OUR CASH FLOW FROM PROJECTS MAY NOT BE IMMEDIATE.

Our forecast contemplates significant expenditures for the acquisition, construction and expansion of our pipelines and related infrastructure. Underwater operations, especially those in water depths in excess of 600 feet, are very expensive and involve much more uncertainty and risk than other operations. Further, if a problem occurs, the solution, if one exists, may be very expensive and time consuming. Accordingly, there is an increase in the frequency and amount of cost overruns related to underwater operations, especially in depths in excess of 600 feet. We cannot assure you that we will be able to complete our projects at the costs currently estimated. If we experience material cost overruns, we would have to finance these overruns using one or more of the following methods:

- borrowing from our revolving credit facility;

- using cash from operations;

- delaying other planned projects;

- issuing additional debt or equity.

Any or all of these methods may not be available when needed or could adversely affect our future results of operations.

Our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction will occur over an extended period of time and we may not receive any material increase in revenue from that project until after the reserves committed to it are developed and produced. If our revenues do not increase at projected levels because of substantial unanticipated delays of any future projects, we might not meet our obligations as they become due.

FERC REGULATION AND A CHANGING REGULATORY ENVIRONMENT COULD AFFECT OUR CASH FLOW.

The FERC extensively regulates certain of our pipelines. This regulation extends to such matters as:

- rate structures;

- rates of return on equity;

- the services that our regulated pipelines are permitted to perform;

- their ability to seek recovery of various categories of costs;

- the acquisition, construction and disposition of assets; and

- to an extent, the level of competition in the interstate pipeline industry.

Given the extent of this regulation, the extensive changes in FERC policy over the last several years, the evolving nature of regulation and the possibility for additional changes, we cannot assure you that the current regulatory regime will remain unchanged or of the effect any changes in that regime would have on our financial position, results of operations or cash flows.

All but one of our regulated pipelines is over 20 years old. As a result, each such pipeline has depreciated significant portions of its initial capital expenditures. Unless those pipelines make additional capital expenditures, they could be fully depreciated within a couple of years. This would reduce the rate base and increase the likelihood that FERC would reduce the approved rates for each of those pipelines.

A NATURAL DISASTER, CATASTROPHE OR OTHER INTERRUPTION EVENT COULD DAMAGE OUR PIPELINES AND OTHER INCOME-PRODUCING ASSETS, CURTAIL THEIR OPERATIONS AND, POSSIBLY, ADVERSELY AFFECT OUR CASH FLOW.

If one or more of our pipelines or other income-producing assets is damaged by severe weather or any other natural disaster, accident, catastrophe or other event, our operations could be significantly interrupted. Similar interruptions could result from damage to production facilities or other production stoppages arising from factors beyond our control. These interruptions might range from a week or less for a minor incident to six months or a year or more for a major interruption. Any event that interrupts the fees generated by our pipelines or other income-producing assets, or which causes us to make significant expenditures not covered by insurance, could adversely impact the market price of, and the amount of cash available for distribution to, the common units. Further, although we carry business interruption insurance that we consider to be appropriate, we cannot assure you that it would cover all types of interruptions that might occur, and in the future we may not be able to obtain other desirable insurance on commercially reasonable terms.

ENVIRONMENTAL COSTS AND LIABILITIES AND CHANGING ENVIRONMENTAL REGULATION COULD AFFECT OUR CASH FLOW.

Our operations are subject to extensive federal, state and local regulatory requirements relating to environmental affairs, health and safety, waste management and chemical products. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including civil fines, injunctions or both. Third parties may also have the right to pursue legal actions to enforce compliance. We will probably make expenditures in connection with environmental matters as part of normal capital expenditure programs. However, future environmental law developments, such as stricter laws, regulations or enforcement policies, could significantly increase our cost of handling, manufacture, use, emission or disposal of substances or wastes. Moreover, as with other companies engaged in similar or related businesses, our operations always have some risk of environmental costs and liabilities because we handle petroleum products. We cannot assure you that we will not incur material environmental costs and liabilities.

THE YEAR 2000 DATE CHANGE MAY RESULT IN DECREASED REVENUES FOR US.

We have established a project team that works with the El Paso Energy Year 2000 executive steering committee to coordinate the phases of our Year 2000 project. We have substantially completed the awareness, assessment, remediation, testing, implementation and contingency planning phases of our Year 2000 program. However, the responses that we have received from third parties, including partners, third party customers and vendors and operators of joint ventures in which we have an interest, regarding their Year 2000 efforts, although generally encouraging, are inconclusive. Further, certain of our systems and processes may be interrelated with systems outside of our control.

Unsuccessful Year 2000 efforts, either on our part or on the part of third parties, may adversely affect our financial position, results of operations and/or cash flows. A significant portion of the oil and natural gas handled by our pipelines is owned by third parties. Accordingly, failure by the owners of oil and natural gas to be ready for the Year 2000 could significantly disrupt the flow of the hydrocarbons to customers. However, in many cases, the owners have no direct contractual relationship with us, and we are relying on our customers to verify the Year 2000 readiness of the producers from whom they purchase oil and natural gas. A portion of our revenue is based upon fees paid by our customers for the reservation of capacity and a portion of the revenue is based upon the volume of actual throughput. As such, short-term disruptions in throughput caused by factors beyond our control may have a financial impact on us and could cause operational problems for our customers. Longer-term disruptions could materially impact our operational and financial condition, and therefore affect the market price of, and our ability to make distributions to, the common units.

CONFLICTS OF INTEREST

EL PASO ENERGY AND ITS AFFILIATES MAY HAVE CONFLICTS OF INTEREST WITH US AND, ACCORDINGLY, YOU.

El Paso Energy is a New York Stock Exchange-traded company whose principal operations include the interstate and intrastate transportation, gathering and processing of natural gas; the marketing of natural gas, power, and other energy-related commodities; power generation and the development and operation of energy infrastructure facilities worldwide. Through its subsidiaries and before giving effect to this offering, El Paso Energy has an effective 34.5% ownership interest in us that it acquired for consideration totalling approximately $482.0 million. El Paso Energy paid approximately $422.0 million in 1998 to acquire an effective 27.3% interest in us, including all of our general partner interests. Then, in June 1999, El Paso Energy acquired $59.8 million in our common units in connection with the Viosca Knoll transaction. Following this offering, El Paso Energy will have an effective 30.3% interest in us. With respect to future investments, El Paso Energy's strategy is for us, when practical, to serve as its primary offshore gathering and transportation growth vehicle in the Gulf of Mexico, although El Paso Energy is not precluded from retaining gathering and transportation opportunities for itself.

El Paso Energy (through a wholly owned subsidiary) elects all of the general partner's directors, who in turn select all of our executive officers and those of the general partner. In addition, El Paso Energy's beneficial ownership of 30.3% of our outstanding units could have a substantial effect on the outcome of some actions requiring unitholder approval.

Although El Paso Energy controls our general partner and has financial incentives to protect its investment by encouraging our success, and it plans to use us when practical as its principal offshore gathering and transportation growth vehicle in the Gulf of Mexico, El Paso Energy is not contractually bound to do so and may reconsider at any time, without notice. Additionally, El Paso Energy is not required to pursue a business strategy that will favor our business opportunities over the business opportunities of El Paso Energy or any of its affiliates (or any other competitor of ours acquired by El Paso Energy). In fact, El Paso Energy may have financial motives to favor our competitors. El Paso Energy and its subsidiaries (many of which are wholly owned) operate in some of the same lines of business and in some of the same geographic areas in which we operate. Although we acquired the remaining interest in Viosca Knoll from El Paso Energy excluding a 1.0% interest in profits and capital, El Paso Energy continues to own pipelines and related facilities located in the Gulf of Mexico, including the Bluewater and Seahawk Shoreline systems. In addition, shareholders of El Paso Energy and Sonat Inc. recently approved a planned merger that is expected to close in late 1999. Sonat also owns pipelines and related assets in the Gulf of Mexico, as well as numerous oil and natural gas properties, including properties in the Gulf of Mexico. To the extent we continue to acquire interests in oil and natural gas properties and if the merger between El Paso Energy and Sonat is completed, our activities may compete with the exploration, development and marketing activities of Sonat conducted by El Paso Energy.

In addition, we have, and we expect to enter into other, significant business relationships with El Paso Energy, our general partner and their affiliates. For instance, in June 1999, we purchased substantially all of El Paso Energy's interest in the Viosca Knoll gathering system, and in October 1998, we purchased the Ewing Bank 958 Unit from El Paso Energy. See "Certain Relationships and Related Transactions" beginning on page 78 and "Business--Recent Developments, Acquisitions and New Projects" beginning on page 48 for a further discussion of the Viosca Knoll and Ewing Bank 958 Unit transactions.

We and our general partner and its affiliates share and, therefore, will compete for, the time and effort of general partner personnel who provide services to us. Officers of the general partner and its affiliates do not, and will not be required to, spend any specified percentage or amount of time on our business. Since these shared officers function as both our representatives and those of our general partner and its affiliates, conflicts of interest could arise between our general partner and its affiliates, on the one hand, and us or you, on the other.

In most instances in which an actual or potential conflict of interest arises between us, on the one hand, and our general partner or its affiliates, on the other hand, there will be a benefit to our general partner or its affiliates in which neither we nor you will share. Such conflicts may arise in situations which include (1) compensation paid to the general partner, which includes incentive distributions and reimbursements for reasonable general and administrative expenses; (2) payments to the general partner and its affiliates for any services rendered to us or on our behalf; (3) our general partner's determination of which direct and indirect costs we must reimburse; (4) decisions to enter into and the terms of transactions between us and our general partner or any of its affiliates, including transactions involving joint ventures, acquisitions and gathering and transportation; (5) the acquisition or operation of businesses by our general partner or its affiliates that would compete with us; and (6) our general partner's determination to establish cash reserves under certain circumstances and thereby decrease cash available for distributions to you.

OUR GENERAL PARTNER RECEIVES MANY FORMS OF COMPENSATION.

Our general partner receives the following compensation:

- distributions in respect of its general and limited partner interests in the partnership;

- distributions in respect of its 1.01% interest in each of our subsidiaries organized as a limited liability company;

- the incentive distributions described in the section entitled "Description of Common Units" beginning on page 81; and

- reimbursements for reasonable general and administrative expenses, and other reasonable expenses, incurred by the general partner and its affiliates for or on our behalf.

Our partnership agreement was not, and many of the other agreements, contracts and arrangements between us, on the one hand, and the general partner and its affiliates, on the other hand, were not and may not be the result of arm's-length negotiations. In addition, we expect to enter into other significant business relationships with the general partner and its affiliates.

OUR GENERAL PARTNER HAS BROAD DISCRETION WITH RESPECT TO OUR MANAGEMENT.

Our general partner, in its capacity as general partner, will make all decisions relating to us. Our general partner's directors and officers have fiduciary duties to manage the general partner, including its investments in its subsidiaries and affiliates, in a manner beneficial to the stockholders of the general partner. In general, the general partner has a fiduciary duty to manage the partnership in a manner beneficial to us and to you. However, the partnership agreement contains provisions that allow the general partner broad discretion in managing our operations and to take into account the interests of parties in addition to us and you in resolving conflicts of interest. By purchasing a common unit, you are deemed to have executed the partnership agreement. Under the partnership agreement, you agree that certain actions by the general partner and its officers and directors, including specifically those identified in this prospectus, are deemed not to breach any duty owed by them to us or to you. Accordingly, if those provisions of the partnership agreement are enforced, the general partner and its officers and directors may not be liable to us or to you for certain actions or omissions that might otherwise be deemed to be a breach of fiduciary duty under Delaware or other applicable state law.

CASH RESERVES, EXPENDITURES AND OTHER MATTERS WITHIN THE DISCRETION OF THE GENERAL PARTNER MAY AFFECT DISTRIBUTIONS.

Our general partner has broad discretion to establish and make additions to cash reserves for any proper partnership purpose, including reserves for the purpose of:

- providing for future capital expenditures;

- stabilizing distributions of cash to unitholders; and

- complying with the terms of any agreement or obligation of ours.

The timing and amount of additions to discretionary reserves could significantly reduce potential distributions that you could receive.

OUR PARTNERSHIP AGREEMENT PURPORTS TO LIMIT OUR GENERAL PARTNER'S FIDUCIARY DUTIES AND CERTAIN OTHER OBLIGATIONS RELATING TO US.

Although our general partner owes certain fiduciary duties to us and will be liable for all our debts, other than non-recourse debts, to the extent not paid by us, certain provisions of our partnership agreement contain exculpatory language purporting to limit the liability of the general partner to us and you. For example, the partnership agreement provides that:

- borrowings of money by us, or the approval thereof by the general partner, will not constitute a breach of any duty of the general partner to us or you whether or not the purpose or effect of the borrowing is to permit distributions on common units or to result in or increase incentive distributions to the general partner;

- any action taken by the general partner consistent with the standards of reasonable discretion set forth in certain definitions in our partnership agreement will be deemed not to breach any duty of the general partner to us or to you; and

- in the absence of bad faith by the general partner, the resolution of conflicts of interest by the general partner will not constitute a breach of the partnership agreement or a breach of any standard of care or duty.

Provisions of the partnership agreement also purport to modify the fiduciary duty standards to which the general partner would otherwise be subject under Delaware law, under which a general partner owes its limited partners the highest duties of good faith, fairness and loyalty. The duty of loyalty would generally prohibit the general partner from taking any action or engaging in any transaction as to which it had a conflict of interest. The partnership agreement permits the general partner to exercise the discretion and authority granted to it in that agreement in managing us and in conducting its retained operations, so long as its actions are not inconsistent with our interests. The general partner and its officers and directors may not be liable to us or to you for certain actions or omissions which might otherwise be deemed to be a breach of fiduciary duty under Delaware or other applicable state law. Further, the partnership agreement requires us to indemnify the general partner to the fullest extent permitted by law, which indemnification, in light of the exculpatory provisions in the partnership agreement, could result in us indemnifying the general partner for negligent acts. Neither El Paso Energy nor any of its other affiliates, other than our general partner, owes fiduciary duties to us.

OUR GENERAL PARTNER AND ITS AFFILIATES MAY SELL UNITS IN THE TRADING MARKET, WHICH COULD REDUCE THE MARKET PRICE OF YOUR COMMON UNITS.

Our general partner and its affiliates currently own 8,953,764 common units. If they were to sell a substantial number of these units in the trading markets, it could reduce the market price of your common units. Our partnership agreement, and other agreements to which we are party, allow our general partner and certain of its affiliates to cause us to register for sale the common units held by such persons. These registration rights allow our general partner and its affiliates to request registration of those common units and to include any of those common units in a registration of other units by us.

RISKS RELATED TO OUR LEGAL STRUCTURE

THE INTERRUPTION OF DISTRIBUTIONS TO US FROM OUR SUBSIDIARIES AND JOINT VENTURES MAY AFFECT OUR ABILITY TO MAKE CASH DISTRIBUTIONS TO YOU.

Leviathan is a holding company. As such, our primary assets are the capital stock and other equity interests in our subsidiaries and joint ventures. Consequently, our ability to make cash distributions depends upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of that cash to us. Distributions from our joint ventures are subject to the discretion of their respective management committees. In addition, several of our joint ventures have credit arrangements that contain various restrictive covenants. Among other things, those covenants limit or restrict such joint ventures' ability to make distributions to us under certain circumstances. Further, the joint venture charter documents typically vest in their management committees sole discretion regarding distributions. We cannot assure you that our joint ventures will continue to make distributions to us at current levels or at all.

Moreover, pursuant to some of the joint venture credit arrangements, we have agreed to return a limited amount of the distributions made to us by the applicable joint venture if certain conditions exist. See "Management's Discussion and Analysis of Financial Condition and Results of Operations--Liquidity and Capital Resources--Sources of Cash" beginning on page 37.

WE CANNOT CAUSE OUR JOINT VENTURES TO TAKE OR NOT TO TAKE CERTAIN ACTIONS UNLESS SOME OR ALL OF OUR JOINT VENTURE PARTNERS AGREE.

Due to the nature of joint ventures, each partner (including Leviathan) in each of our joint ventures has made substantial contributions and other commitments to that joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each partner with the opportunity to protect its investment in that joint venture, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These protective features include a corporate governance structure which requires at least a majority in interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100%) to authorize more significant activities. Depending on the particular joint venture, these more significant activities might involve large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money, transactions with affiliates of a joint venture partner, litigation and/or transactions not in the ordinary course of business, among others. Thus, without the concurrence of joint venture partners with enough voting interests, we cannot cause any of our joint ventures to take or not to take certain actions, even though such actions may be in the best interest of the particular joint venture or Leviathan.

WE DO NOT HAVE THE SAME FLEXIBILITY AS OTHER TYPES OF ORGANIZATIONS TO ACCUMULATE CASH AND EQUITY TO PROTECT AGAINST ILLIQUIDITY IN THE FUTURE.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts reserved for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our common units will decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

CHANGES OF CONTROL OF OUR GENERAL PARTNER MAY ADVERSELY AFFECT YOU.

Our results of operations and, thus, our ability to make cash distributions could be adversely affected if there is a change in management resulting from a change of control of our general partner. Although such an action would result in a change of control under the terms of the indenture governing our publicly-held debt, El Paso Energy is not restricted from selling the general partner or any of the common units it holds. As a result, El Paso Energy could sell control of our general partner to another company with less familiarity and experience with our businesses and with different business philosophies and objectives. We cannot assure you that any such acquiror would continue our current business strategy, or even a business strategy economically compatible with our current business strategy.

TAX RISKS

For general discussion of the expected federal income tax consequences of owning and disposing of common units, see "Income Tax Considerations" beginning on page 95.

WE HAVE NOT RECEIVED A RULING OR ASSURANCES FROM THE IRS ON ANY MATTERS AFFECTING US.

We have not requested, and will not request, any ruling from the Internal Revenue Service with respect to our classification, or the classification of any of our subsidiaries which are organized as limited liability companies or partnerships, as a partnership for federal income tax purposes or any other matter affecting us or our subsidiaries. Accordingly, the IRS may propose positions that differ from the conclusions expressed by our counsel in this prospectus. It may be necessary to resort to administrative or court proceedings in an effort to sustain some or all of those conclusions, and some or all of those conclusions ultimately may not be sustained. The common unitholders and the general partner will bear, directly or indirectly, the costs of any contest with the IRS.

OUR TAX TREATMENT DEPENDS ON OUR PARTNERSHIP STATUS.

Based upon the continued accuracy of the representations of the general partner set forth in "Income Tax Considerations--Partnership Status" on page 96, our counsel believes that under current law and regulations we and our subsidiaries which are limited liability companies or partnerships have been and will be classified as partnerships for federal income tax purposes. However, as stated above, we have not requested, and will not request, any ruling from the IRS as to this status, and our counsel's opinion is not binding on the IRS. In addition, you cannot be sure that those representations will continue to be accurate. If the IRS were to challenge our federal income tax status or the status of one of our subsidiaries, such a challenge could result in (1) an audit of your entire tax return, and (2) adjustments to items on that return that are unrelated to the ownership of common units. In addition, you would bear the cost of any expenses incurred in connection with an examination of your personal tax return. Except as specifically noted, this discussion assumes that we and our subsidiaries which are organized as limited liability companies or partnerships have been and are treated as partnerships for federal income tax purposes.

If we or any of our subsidiaries which are organized as limited liability companies were taxable as a corporation for federal income tax purposes in any taxable year, its income, gain, losses and deductions would be reflected on its tax return rather than being passed through (proportionately) to you, and its net income would be taxed at corporate rates. In addition, some or all of the distributions made to you would be treated as dividend income and would be reduced as a result of the federal, state and local taxes paid by us or our subsidiaries.

WE MAINTAIN UNIFORMITY OF COMMON UNITS THROUGH NONCONFORMING DEPRECIATION CONVENTIONS.

Since we cannot match transferors and transferees of common units, we must maintain uniformity of the economic and tax characteristics of the common units to their purchasers. To maintain uniformity and for other reasons, we have adopted certain depreciation conventions which do not conform with all aspects of certain proposed and final Treasury Regulations. The IRS may challenge those conventions and, if such a challenge were sustained, the uniformity or the value of common units may be affected. For example, non-uniformity could adversely affect the amount of tax depreciation available to you and could have a negative impact on the value of your common units.

WE CAN ONLY DEDUCT CERTAIN LOSSES.

Any losses that we generate will be available to offset future income (except certain portfolio net income) that we generate and cannot be used to offset income from any other source, including other passive activities or investments.

YOUR PARTNERSHIP TAX INFORMATION MAY BE AUDITED.

We will furnish you a substitute Schedule K-1 that sets forth your allocable share of income, gains, losses and deductions. In preparing this schedule, we will use various accounting and reporting conventions and various depreciation and amortization methods we have adopted. You cannot be sure that this schedule will yield a result that conforms to statutory or regulatory requirements or to administrative pronouncements of the IRS. Further, our tax return may be audited, and any such audit could result in an audit of your individual tax return as well as increased liabilities for taxes because of adjustments resulting from the audit.

YOUR TAX LIABILITY RESULTING FROM AN INVESTMENT IN OUR UNITS COULD EXCEED ANY CASH YOU RECEIVE AS A DISTRIBUTION FROM US OR THE PROCEEDS FROM DISPOSITIONS OF THOSE UNITS.

You will be required to pay federal income tax and, in certain cases, state and local income taxes on your allocable share of our income, whether or not you receive any cash distributions from us. You cannot be sure that you will receive cash distributions equal to your allocable share of taxable income from us. In fact, you may incur tax liability in excess of the amount of cash distribution we make to you or the cash you receive on the sale of your units.

TAX-EXEMPT ORGANIZATIONS AND CERTAIN OTHER INVESTORS SHOULD CAREFULLY CONSIDER OWNERSHIP OF COMMON UNITS.

Investment in common units by tax-exempt organizations and regulated investment companies raises issues unique to such persons.

WE ARE REGISTERED AS A TAX SHELTER. ANY IRS AUDIT WHICH ADJUSTS OUR RETURNS WOULD ALSO ADJUST YOURS.

We have been registered with the IRS as a "tax shelter." The tax shelter registration number is 93084000079. As a result, you cannot be sure that we will not be audited by the IRS or that tax adjustments will not be made. If you own less than a 1% profit interest in us, your right to participate in the income tax audit process is limited. Further, any adjustments in our tax returns will lead to adjustments in your returns and may lead to audits of your returns and adjustments of items unrelated to us. You would bear the cost of any expenses incurred in connection with an examination of your personal tax return.

USE OF PROCEEDS

We expect to realize approximately $91.6 million in net proceeds from the sale of common units offered by this prospectus. We plan to use the net proceeds, including any related to the exercise of the underwriters' over-allotment option, to repay indebtedness under our revolving credit facility. We may reborrow funds available under the revolving credit facility in the future to fund our portion of pipeline construction costs for our new Nemo joint venture; to construct a platform and other infrastructure facilities at our Ewing Bank 958 Unit oil and natural gas property; to construct and purchase pipelines, platforms and other hydrocarbon related facilities; and for general business purposes.

As of August 9, 1999, we had $300.0 million outstanding under our revolving credit facility bearing interest at an average floating rate of 7.7% per annum with a final maturity of May 2002. Over the past 12 months, we used borrowings under our revolving credit facility to, among other things, (1) finance the UTOS/HIOS/East Breaks acquisition (approximately $51.0 million), (2) finance a portion of the acquisition and development of our non-producing oil and gas property, the Ewing Bank 958 Unit ($30.0 million), (3) finance the construction and installation of a new platform and production handling facilities at East Cameron Block 373 ($9.4 million), (4) pay amounts related to the abandonment of the Ewing Bank flowlines ($2.9 million), (5) finance the construction of the Allegheny oil pipeline ($22.8 million), (6) pay employee benefits costs related to El Paso Energy's acquisition of our general partner ($8.6 million), (7) pay transaction costs and (8) fund general working capital requirements. In addition to the expenditures from borrowings under our revolving credit facility listed above, we used a portion of the proceeds from our May 1999 offering of our senior subordinated notes to repay indebtedness under our revolving credit facility, to finance a portion of the Viosca Knoll transaction (approximately $19.9 million), and to repay indebtedness under the Viosca Knoll credit facility (approximately $33.4 million).

Over the next 12 months, we expect our capital expenditures for budgeted projects to range from $30.0 to $100.0 million, depending on the number and types of projects in which we participate and the level and nature of that participation. We may use borrowings under our revolving credit facility to fund these projects. We currently are reviewing a large number of potential natural gas and oil pipeline, platform, development and other infrastructure opportunities with a total capital cost estimated to be in excess of $200 million. We expect to pursue many of these projects, including some in which we currently own a 100% interest, through joint ventures, strategic alliances or other participatory arrangements. Often, we structure these joint ventures, in which we usually own an interest of 50.0% or less, so they may independently access capital, like non-recourse or limited recourse project financing.

We used the $33.4 million that El Paso Energy contributed to Viosca Knoll at the closing of that acquisition and $33.4 million of the proceeds from our senior subordinated note offering to repay in full and terminate the Viosca Knoll credit facility on June 1, 1999. Over the past 12 months, Viosca Knoll used borrowings under its credit facility for the addition of compression facilities to and expansion of the Viosca Knoll system and for other working capital needs. For additional information on the Viosca Knoll transaction, see "Business--Natural Gas and Oil Pipelines--Viosca Knoll System" beginning on page 53.

MARKET PRICE OF AND DISTRIBUTIONS ON UNITS

MARKET INFORMATION

The common units and preference units are listed on the NYSE, which is the principal trading market for these securities. The common units are listed under the symbol "LEV" and the preference units are listed under the symbol "LEV.P". On August 25, 1999, the last reported per unit sales prices of the common units and preference units on the NYSE were $23.875 and $24.00, respectively. The following table sets forth the high and low sales prices for the common units and preference units as reported on the NYSE and the cash distributions declared per common unit and preference unit for the periods indicated.

	PRICE RANGE				DISTRIBUTIONS DECLARED PER UNIT	
	COMMON UNITS		PREFERENCE UNITS			
	HIGH	LOW	HIGH	LOW	COMMON UNIT	PREFERENCE UNIT
Year ended December 31, 1999						
Second Quarter..............	$24.750	$21.375	$23.250	$20.500	$0.525	$0.275
First Quarter...............	23.125	19.500	20.875	17.625	0.525	0.275
Year ended December 31, 1998						
Fourth Quarter..............	$28,500	$19.750	$25.000	$17.375	$0.525	$0.275
Third Quarter*..............	27.875	21.500	29.750	21.250	0.525	0.275
Second Quarter..............	*	*	34.000	25.500	0.525	0.525
First Quarter...............	*	*	33.625	27.000	0.525	0.525
Year ended December 31, 1997						
Fourth Quarter..............	*	*	$33.125	$28.000	$0.500	$0.500
Third Quarter...............	*	*	28.750	23.250	0.475	0.475
Second Quarter..............	*	*	26.375	20.375	0.450	0.450
First Quarter...............	*	*	24.250	19.000	0.425	0.425
Year ended December 31, 1996						
Fourth Quarter..............	*	*	$ 22.81	$ 20.75	$0.400	$0.400
Third Quarter...............	*	*	21.19	18.00	0.375	0.375
Second Quarter..............	*	*	18.00	15.69	0.350	0.350
First Quarter...............	*	*	16.19	13.75	0.325	0.325

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* At the close of business on August 5, 1998, we issued replacement common units to the holders of then outstanding preference units that elected to convert their preference units into common units. The holders of approximately 94% of preference units elected to convert. Trading commenced for the common units on the NYSE on August 6, 1998. Prior to such date, there was no active trading market for the common units.

HOLDERS

As of March 5, 1999, there were approximately 468 and 125 holders of record of common units and preference units, respectively.

DISTRIBUTIONS

Our partnership agreement requires us to distribute, within 45 days after the end of each calendar quarter, all of our "available cash," as such term is defined in our partnership agreement. Generally, "available cash" means, for the applicable quarter, all cash receipts for such quarter and any reductions in reserves established in prior quarters less all cash disbursements made in such quarter and additions to reserves, as determined by our general partner. Our partnership agreement characterizes available cash into two categories -- "cash from operations" and "cash from interim capital contributions," each of which is described in the section "Description of Common Units." To date, we have only distributed available cash constituting cash from operations, and we do not anticipate making distributions of available cash constituting cash from interim capital transactions in the next six months.

CAPITALIZATION

The following table sets forth our consolidated capitalization on a historical basis as of June 30, 1999 and our unaudited consolidated capitalization as adjusted to reflect (1) sale of the common units offered pursuant to this prospectus and (2) the capital contribution by our general partner in order to maintain its 1% general partner interest in us as a result of issuing additional common units. See "Use of Proceeds" beginning on page 27. You should read this table along with "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 32.

	AS OF JUNE 30, 1999	
	ACTUAL	AS ADJUSTED
	(IN THOUSANDS)	
Long-term debt:		
Revolving credit facility	$306,500	$213,975
Senior subordinated notes due 2009	175,000	175,000
Total long-term debt	481,500	388,975
Minority interest	(249)	(249)
Partners' capital	120,036	212,561
Total capitalization	$601,287	$601,287

SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The historical financial information for each of the three years ended December 31, 1996, 1997 and 1998 and as of December 31, 1997 and 1998 was derived from our consolidated financial statements and notes thereto included elsewhere in this prospectus. The historical financial information for the years ended December 31, 1994 and 1995 and as of December 31, 1994, 1995 and 1996 has been derived from our historical consolidated financial statements (not included herein). The historical financial data for each of the six months ended June 30, 1998 and 1999 and as of June 30, 1999 was derived from our historical unaudited consolidated financial statements and notes thereto included elsewhere in this prospectus. The historical financial data as of June 30, 1998 has been derived from our unaudited historical consolidated financial statements (not included herein). We believe that all material adjustments, consisting only of normal recurring adjustments necessary for the fair presentation of our interim results, have been included. Results of operations for any interim period are not necessarily indicative of the results of operations for the entire year due to the seasonal nature of our business. You should read this information along with "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 32, "Business and Properties" beginning on page 45 and the consolidated financial statements and notes thereto listed on pages F-1 and F-2.

	YEAR ENDED DECEMBER 31,					(UNAUDITED) SIX MONTHS ENDED JUNE 30,	
	1994	1995	1996	1997	1998	1998	1999
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)						
STATEMENT OF OPERATIONS:							
Oil and natural gas sales	$ 796	$ 1,858	$ 47,068	$ 58,106	$ 31,411	$ 15,734	$ 15,100
Gathering, transportation and platform services	18,554	20,547	24,005	17,329	17,320	7,782	10,798
Equity in earnings	14,786	19,588	20,434	29,327	26,724	12,571	19,953
Total revenue	34,136	41,993	91,507	104,762	75,455	36,087	45,851
Operating expenses	1,876	4,092	9,068	11,352	11,369	5,546	5,025
Depreciation, depletion and amortization	5,085	8,290	31,731	46,289	29,267	14,845	13,727
Impairment, abandonment and other	--	--	--	21,222	(1,131)	--	--
General and administrative expenses and management fee	5,408	7,069	8,540	14,661	16,189	7,503	5,909
Total operating costs	12,369	19,451	49,339	93,524	55,694	27,894	24,661
Operating income	21,767	22,542	42,168	11,238	19,761	8,193	21,190
Interest income and other	1,293	1,884	1,710	1,475	771	157	268
Interest and other financing costs	(912)	(833)	(5,560)	(14,169)	(20,242)	(8,429)	(13,868)
Minority interest in (income) loss	(216)	(251)	(427)	7	(15)	(3)	(80)
Income (loss) before income taxes	21,932	23,342	37,891	(1,449)	275	(82)	7,510
Income tax benefit	136	603	801	311	471	168	177
Net income (loss)	$ 22,068	$ 23,945	$ 38,692	$ (1,138)	$ 746	$ 86	$ 7,687
Basic and diluted net income (loss) per unit	$ 1.02	$ 0.97	$ 1.57	$ (0.06)	$ 0.02	$ 0.00	$ 0.25
CASH DISTRIBUTIONS DECLARED PER UNIT:							
Preference unit	$ 1.20	$ 1.20	$ 1.45	$ 1.85	$ 1.60	$ 1.05	$ 0.55
Common unit	$ 1.20	$ 1.20	$ 1.45	$ 1.85	$ 2.10	$ 1.05	$ 1.05

	YEAR ENDED DECEMBER 31,					SIX MONTHS ENDED JUNE 30,	
	1994	1995	1996	1997	1998	1998	1999
						(UNAUDITED)	
	(IN THOUSANDS)						
BALANCE SHEET DATA (AT END OF PERIOD):							
Property and equipment, net	$126,802	$285,275	$286,555	$200,639	$241,992	$201,503	$381,210
Equity investments	80,560	82,441	107,838	182,301	186,079	186,147	219,732
Total assets	231,043	398,696	453,526	409,842	442,726	406,087	625,913
Total debt	8,000	135,780	227,000	238,000	338,000	270,000	481,500
Total partners' capital	192,431	186,841	192,023	143,966	82,896	113,557	120,036
OTHER FINANCIAL DATA:							
EBITDA(1)	$ 26,852	$ 30,832	$ 73,899	$ 78,749	$ 47,897	$ 23,038	$ 34,917
Adjusted EBITDA(2)	27,136	35,886	90,288	76,557	52,344	23,765	39,072
Net cash provided by operating activities	51,716	74,886	50,179	67,485	25,677	12,884	23,640
Net cash used in investing activities	98,285	172,382	101,721	41,769	65,624	19,366	92,818
Net cash provided by (used in) financing activities	57,744	95,580	52,525	(35,775)	36,625	1,194	69,371
Capital expenditures included in investing activities	98,398	173,632	101,721	41,957	66,111	19,366	92,818

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(1) EBITDA is defined for this purpose as operating income before depreciation, depletion and amortization and impairment, abandonment and other. EBITDA is used as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to net income, as an indicator of our operating performance or as an alternative to cash flows from operating activities as a measure of liquidity. EBITDA may not be a comparable measurement among different companies. EBITDA is presented here to provide additional information about us.

(2) Adjusted EBITDA is defined for this purpose as EBITDA plus cash distributions from equity investments less earnings attributable to equity investments. We believe Adjusted EBITDA is a meaningful disclosure because of the significance of our equity investments. Adjusted EBITDA is used as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to net income, as an indicator of our operating performance or as an alternative to cash flows from operating activities as a measure of liquidity. Adjusted EBITDA may not be a comparable measurement among different companies. Adjusted EBITDA is presented here to provide additional information about us.

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

You should read the following discussion in conjunction with (1) our consolidated financial statements and the notes thereto incorporated into this prospectus by reference and (2) the information set forth under the heading "Selected Historical Consolidated Financial Data." The following discussion should assist your understanding of our financial position and results of operations for the six months ended June 30, 1999 and 1998 and for each of the years ended December 31, 1998 and 1997. Unless the context otherwise requires, all references below to "we," "us" or "our" are also references to our subsidiaries.

OVERVIEW

We are a provider of integrated energy services, including natural gas and oil gathering, transportation, midstream and other related services in the Gulf of Mexico. Either directly or through our joint ventures, we own interests in eight natural gas pipeline systems, an oil gathering system, six strategically-located multi-purpose offshore platforms, production handling and dehydration facilities and five oil and natural gas properties.

Our natural gas pipelines, located primarily offshore Louisiana and Mississippi, gather and transport natural gas for producers, marketers, pipelines and end-users for a fee. Our current interests in operating natural gas pipelines consist of: a 100% interest in each of Green Canyon and Tarpon; a 99.0% interest in Viosca Knoll; a 50.0% interest in Stingray; a 60.0% interest in HIOS; a 66.7% interest in UTOS; and an effective 25.7% interest in each of Manta Ray Offshore and Nautilus. Our natural gas pipelines include 1,200 miles of pipeline with a throughput capacity of 6.8 billion cubic feet ("Bcf") of natural gas per day.

We own a 36.0% interest in the Poseidon oil pipeline. The Poseidon oil pipeline is located primarily offshore Louisiana and consists of approximately 300 miles of pipeline with a throughput capacity of 400,000 barrels of oil per day.

We operate and own interests in six strategically-located, multi-purpose platforms in the Gulf of Mexico, including a 100% interest in five platforms--Viosca Knoll Block 817, East Cameron Block 373, Ship Shoal Block 332, South Timbalier Block 292 and Ship Shoal Block 331--and a 50.0% interest in the Garden Banks Block 72 platform. These platforms have production handling capabilities which complement our pipeline operations and play a key role in the development of oil and natural gas reserves. We also own a 50.0% interest in West Cameron Dehy, a dehydration and production handling facility located at the northern terminus of the Stingray system, onshore Louisiana.

In addition, with our joint venture partners, we are constructing two natural gas pipelines through newly created joint ventures, East Breaks Gathering Company, L.L.C. and Nemo Gathering Company, LLC, and we have recently completed the construction of a wholly owned oil pipeline which we expect to become operational in the fourth quarter of 1999, the Allegheny System.

RECENT FINANCING DEVELOPMENTS

PREFERENCE UNIT CONVERSION. Holders of approximately 71% of our remaining outstanding preference units as of August 12, 1999 opted to convert those units into common units by the expiration of our second 90 day conversion option period, which commenced on May 14, 1999 and ended on August 12, 1999. During the first conversion option period, during substantially the same period in 1998, approximately 94% of our then outstanding preference units were converted into common units. As a result of the completion of the second conversion option period, a total of 291,299 preference units are outstanding.

SUBORDINATED NOTES OFFERING. On May 27, 1999, we borrowed $175 million pursuant to the issuance, at par, of senior subordinated notes. These senior subordinated notes, which were issued under an indenture, bear interest at a rate of 10 3/8% per annum, payable semi-annually, mature on June 1, 2009, and are currently guaranteed by all of our subsidiaries. For more information about our subordinated notes, see "--Liquidity and Capital Resources--Sources of Cash."

EXTENSION OF OUR CREDIT FACILITY. Concurrently with the closing of the offering of our senior subordinated notes, we amended our $375.0 million revolving credit facility to, among other things, extend the maturity to May 2002 from December 1999. As of August 9, 1999, we had $300.0 million outstanding under the revolving credit facility bearing interest at an average floating rate of 7.7% per annum.

NEW WESTERN GULF JOINT VENTURE CREDIT FACILITY. Western Gulf, which owns HIOS and East Breaks, entered into a $100.0 million revolving credit facility in February 1999 with a syndicate of commercial banks to fund substantially all of the costs of the East Breaks system and other working capital needs of Western Gulf, East Breaks and HIOS. This credit facility is secured by certain assets of the joint venture and matures in February 2004. As of August 9, 1999, Western Gulf had $50.1 million outstanding under its credit facility, bearing interest at an average floating rate of 6.5% per annum, and $49.9 million of additional availability under the facility. Including the 20% interest we recently acquired from NGPL, we now own 60.0% of Western Gulf.

TERMINATION OF VIOSCA KNOLL JOINT VENTURE CREDIT FACILITY. In connection with our acquisition of substantially all of the interest that we did not previously own in our Viosca Knoll joint venture, we repaid the balance outstanding under and terminated the $100.0 million credit facility which that joint venture had obtained in December 1996.

RESULTS OF OPERATIONS

SIX MONTHS ENDED JUNE 30, 1999 COMPARED WITH SIX MONTHS ENDED JUNE 30, 1998

Oil and natural gas sales totaled $15.1 million for the six months ended June 30, 1999 as compared with $15.7 million for the same period in 1998. The decrease is attributable to (1) substantially lower realized oil and natural gas prices and (2) normal production declines from our oil and natural gas properties, partially offset by production from properties we acquired in August 1998. During the six months ended June 30, 1999, we produced and sold 6,877 million cubic feet ("MMcf") of natural gas and 193,000 barrels of oil at average prices of $1.83 per thousand cubic feet ("Mcf") and $12.69 per barrel, respectively. During the same period in 1998, we produced and sold 4,874 MMcf of natural gas and 308,000 barrels of oil at average prices of $2.16 per Mcf and $16.53 per barrel.

Revenue from gathering transportation and platform services totaled $8.3 million for the six months ended June 30, 1999, net of $2.4 million related to the effect of consolidating Viosca Knoll's results beginning on June 1, 1999 as compared with $7.8 million for the same period in 1998. The $0.5 million increase primarily reflects an increase of $2.7 million in platform services revenue from our East Cameron Block 373 platform which was placed in service in April 1998 offset by decreases of (1) $1.3 million in gathering revenues as a result of lower throughput on the Green Canyon and Tarpon systems primarily due to normal declines in production and (2) $0.9 million in platform access fees because we acquired additional interests in the Viosca Knoll Block 817 lease in August 1998.

Revenue from our joint ventures totaled $20.0 million for the six months ended June 30, 1999 as compared with $11.8 million for the same period in 1998 after taking out the effect of consolidating Viosca Knoll's results of operations beginning on June 1, 1999. The increase of $8.2 primarily reflects increases of (1) $0.8 million related to Stingray as a result of reductions in prior period estimates of reserves of uncollectible revenues and (2) $8.4 million from Poseidon Oil Pipeline Company, West Cameron Dehy, Nautilus and Manta Ray Offshore as a result of increased throughput, offset by a decrease of $1.0 million as a result of decreased throughput on HIOS and UTOS. Total natural gas throughput volumes for our joint ventures increased approximately 3% from the six months ended June 30, 1998 to the same period in 1999 primarily as a result of increased throughput on the Viosca Knoll, Nautilus and Manta Ray Offshore systems. Oil volumes from the Poseidon pipeline totaled 29.5 million barrels and 15.7 million barrels for the six months ended June 30, 1999 and 1998.

Depreciation, depletion and amortization totaled $13.4 million for the six months ended June 30, 1999 after taking out the effect of consolidating Viosca Knoll's results of operations beginning on June 1, 1999 as compared with $14.8 million for the same period in 1998. The decrease of $1.4 million reflects a decrease of $1.8 million in depreciation and depletion of oil and natural gas wells and facilities located on the Viosca Knoll Block 817, Garden Banks Block 72 and the Garden Banks Block 117 as a result of decreased depletion and abandonment accrual rates offset by a $0.4 million increase in depreciation on our East Cameron Block 373 and Ship Shoal Block 331 platforms placed in service after March 31, 1998.

General and administrative expenses, including our general partner's management fee, totaled $5.9 million for the six months ended June 30, 1999, as compared with $7.5 million for the same period in 1998. The decrease of $1.6 million reflects decreases of (1) $0.1 million in our general partner's management fee and (2) $1.5 million in direct general and administrative expenses primarily related to the appreciation and vesting of unit rights granted to certain officers and employees under a compensation plan that was terminated in October 1998.

Interest and other financing costs, excluding capitalized interest, for the six months ended June 30, 1999 totaled $14.6 million as compared with $8.4 million for the same period in 1998. During the six months ended June 30, 1999 and 1998, we capitalized $0.8 million and $0.5 million, respectively, of interest costs in connection with construction projects and drilling activities in progress during such periods. During the six months ended June 30, 1999 and 1998, we had outstanding indebtedness under our credit facility averaging approximately $332.0 million and $254.0 million, respectively, at average interest rates of 7.3% and 6.5% per annum. Additionally, our senior subordinated notes, issued in May 1999, bear interest at 10 3/8% per annum.

Net income for the six months ended June 30, 1999, totaled $7.7 million, or $0.25 per unit, as compared with $86,000, or $0.00 per unit, for the six months ended June 30, 1998, as a result of the items discussed below.

YEAR ENDED DECEMBER 31, 1998 COMPARED WITH YEAR ENDED DECEMBER 31, 1997

Oil and natural gas sales totaled $31.4 million for the year ended December 31, 1998 as compared with $58.1 million for the same period in 1997. The decrease is attributable to (1) substantially lower realized oil and natural gas prices, (2) decreased production as a result of two tropical storms and Hurricane Georges passing through the Gulf of Mexico during the third quarter of 1998, (3) normal production declines from our oil and natural gas properties and (4) the lack of acceptable markets downstream of the Viosca Knoll system. The production decline attributable to the capacity constraints of the downstream transporter was alleviated during the third quarter of 1998. During the year ended December 31, 1998, we produced and sold 11,324 MMcf of natural gas and 540,000 barrels of oil at average prices of $2.01 per Mcf and $15.69 per barrel. During the same period in 1997, we produced and sold 19,792 MMcf of natural gas and 801,000 barrels of oil at average prices of $2.08 per Mcf and $20.61 per barrel.

Revenue from gathering, transportation and platform services totaled $17.3 million for each of the years ended December 31, 1998 and 1997. The activity for 1998 remained consistent with the prior year as a result of an increase of $5.5 million in platform services revenue from our East Cameron Block 373 platform, which was placed in service in April 1998, offset by decreases of (1) $2.8 million related to the cessation of production in May 1997 from the only well connected to the Ewing Bank system, (2) $1.9 million as a result of lower throughput on the Green Canyon system and the contribution of a significant portion of the Manta Ray system to Manta Ray Offshore on January 17, 1997, resulting in revenue from these assets being included in equity in earnings for the entire year ended December 31, 1998 as compared with a portion of the year ended December 31, 1997 and (3) $0.8 million in platform revenue services from our Viosca Knoll Block 817 platform as a result of lower oil and natural gas volumes processed on the platform due to capacity constraints of a downstream transporter which were alleviated during the third quarter of 1998. Throughput volumes for our wholly owned gathering systems decreased approximately 8.0% for the year ended December 31, 1998 as compared with the same period in 1997.

Revenue from our joint ventures totaled $26.7 million for the year ended December 31, 1998 as compared with $29.3 million for the same period in 1997. The decrease of $2.6 million primarily reflects decreases of (1) $6.7 million related to non-recurring start-up costs, changes in prior period estimates and a change in equity ownership of Nautilus and Manta Ray Offshore and (2) $2.5 million related to Stingray and HIOS as a result of increased maintenance costs and decreased throughput offset by an increase of $6.6 million from Poseidon, Viosca Knoll, UTOS and West Cameron Dehy as a result of increased throughput. Total natural gas throughput volumes for our joint ventures increased approximately 20.0% from the year ended December 31, 1997 to the same period in 1998 primarily as a result of increased throughput on the Viosca Knoll, UTOS, Nautilus and Manta Ray Offshore systems. Oil volumes from Poseidon totaled 35.6 million barrels ("MMbbls") and 19.0 MMbbls for the year ended December 31, 1998 and 1997, respectively. Our joint ventures were impacted by two tropical storms and Hurricane Georges passing through the Gulf of Mexico during the third quarter of 1998.

Operating expenses totaled $11.4 million for each of the years ended December 31, 1998 and 1997. The 1998 activity remained consistent with the prior year as a result of lower operating and transportation costs associated with our oil and natural gas properties offset by higher operating costs associated with the East Cameron Block 373 platform placed in service in April 1998, the acquisition of the Ship Shoal Block 331 platform in August 1998 and additional activities associated with the Ship Shoal Block 332 platform.

Depreciation, depletion and amortization totaled $29.3 million for the year ended December 31, 1998 as compared with $46.3 million for the same period in 1997. The decrease of $17.0 million reflects decreases of (1) $14.0 million in depreciation and depletion on oil and natural gas wells and facilities located on the Viosca Knoll Block 817, Garden Banks Block 72 and the Garden Banks Block 117 as a result of decreased production from these leases and slightly lower estimated abandonment obligations and (2) $3.0 million in depreciation on pipelines, platforms and facilities as a result of us fully depreciating our investment in the Ewing Bank and Ship Shoal systems in June 1997, offset by increased depreciation attributable to our East Cameron Block 373 and Ship Shoal Block 331 platforms placed in service in 1998.

Impairment, abandonment and other totaled ($1.1 million) for the year ended December 31, 1998 and represented the excess of accrued costs over actual costs incurred associated with the abandonment of our Ewing Bank flowlines. Impairment, abandonment and other totaled $21.2 million for the year ended December 31, 1997 and consisted of a non-recurring charge to reserve our investment in certain gathering facilities and other assets associated with Tatham Offshore's Ewing Bank 914 #2 well and Ship Shoal Block 331 property, to accrue our abandonment obligations associated with the gathering facilities serving these properties, to reserve our noncurrent receivable related to the prepayment of the demand charge obligations under certain agreements related to the Ewing Bank and Ship Shoal leases and to accrue certain abandonment obligations associated with its oil and natural gas properties.

General and administrative expenses, including the management fee allocated from our general partner, totaled $16.2 million for the year ended December 31, 1998 as compared with $14.7 million for the same period in 1997. The increase of $1.5 million reflects increases of (1) $1.0 million in management fee allocated by our general partner to us as a result of our increased construction and operational activities and (2) $0.5 million in our direct general and administrative expenses primarily related to the vesting and appreciation of unit rights to certain of our officers and employees.

Interest income and other totaled $0.8 million for the year ended December 31, 1998 as compared with $1.5 million for the same period in 1997.

Interest and other financing costs, excluding capitalized interest, for the year ended December 31, 1998 totaled $20.2 million as compared with $14.2 million for the same period in 1997. During the year ended December 31, 1998 and 1997, we capitalized $1.1 million and $1.7 million, respectively, of interest costs in connection with construction projects and drilling activities in progress during such periods. During the years ended December 31, 1998 and 1997, we had outstanding indebtedness averaging approximately $288.0 million and $232.5 million.

Net income for the year ended December 31, 1998 totaled $0.7 million, or $0.02 per unit, as compared with a net loss of $1.1 million, or $0.06 per unit, for the year ended December 31, 1997 as a result of the items discussed above.

YEAR ENDED DECEMBER 31, 1997 COMPARED WITH YEAR ENDED DECEMBER 31, 1996

Oil and natural gas sales totaled $58.1 million for the year ended December 31, 1997 as compared with $47.1 million for the year ended December 31, 1996. The increase of $11.0 million is attributable to increased production from our oil and natural gas properties as a result of initiating full production from Viosca Knoll Block 817 in March 1996, Garden Banks Block 72 in May 1996 and Garden Banks Block 117 in July 1996. During the year ended December 31, 1997, we produced and sold 19,792 MMcf of natural gas and 801.0 Mbbls of oil at average prices of $2.08 per Mcf and $20.61 per barrel, respectively. During 1996, we produced and sold 15,730 MMcf of natural gas and 393.0 Mbbls of oil at average prices of $2.37 per Mcf and $21.76 per barrel, respectively.

Revenue from gathering, transportation and platform services totaled $17.3 million for the year ended December 31, 1997 as compared with $24.0 million for the year ended December 31, 1996. The decrease of $6.7 million reflects decreases of (1) $7.6 million as a result of the contribution of a significant portion of the Manta Ray system to Manta Ray Offshore in January 1997 resulting in revenue from these assets being included in equity in earnings for the remainder of the year ended December 31, 1997 and (2) $3.0 million related to lower throughput on the Ewing Bank system offset by increases of (1) $1.8 million in platform services from our Viosca Knoll Block 817 platform as a result of additional oil and natural gas volumes processed on the platform and (2) $2.1 million from the Tarpon and Green Canyon systems primarily related to (x) the deregulation of the Tarpon system allowing us to recognize additional revenue during the current period related to the gathering fees collected in prior periods and (y) new production attached to these systems. Throughput volumes for our wholly owned gathering systems decreased 34.0% for the year ended December 31, 1997 as compared with the year ended December 31, 1996 primarily due to an 82.0% decline from the Ewing Bank system due to a downhole mechanical problem in May 1997 which caused Tatham Offshore's Ewing Bank 914 #2 well to be shut-in.

Revenue from our joint ventures totaled $29.3 million for the year ended December 31, 1997 as compared with $20.4 million for the year ended December 31, 1996. The increase of $8.9 million primarily reflects increases of (1) $2.9 million from Viosca Knoll and UTOS as a result of increased throughput, (2) $1.6 million from Poseidon, which placed the Poseidon system in service in three-phases, April 1996, December 1996 and December 1997, (3) $0.4 million from West Cameron Dehy, (4) $3.7 million from Manta Ray Offshore related to the Manta Ray assets contributed by Leviathan and (5) $2.2 million from Nautilus, primarily as a result of Nautilus recognizing as other income an allowance for funds used during construction, offset by (6) a $1.9 million decrease in Stingray and HIOS as a result of increased maintenance costs during 1997. Total natural gas throughput volumes for our joint ventures increased approximately 9.0% from 1996 to 1997 primarily as a result of increased throughput on the Viosca Knoll and UTOS systems as well as the addition of the Manta Ray Offshore system throughput as a joint venture, as discussed above. Oil volumes from Poseidon totaled 19.0 MMbbls for the year ended December 31, 1997 as compared with 7.5 MMbbls for the period from inception of operations in April 1996 through December 31, 1996.

Operating expenses for the year ended December 31, 1997 totaled $11.4 million as compared with $9.1 million for the year ended December 31, 1996. The increase of $2.3 million is primarily attributable to additional maintenance costs related to the platforms we operate and our operation of one additional oil and natural gas well during 1997.

Depreciation, depletion and amortization totaled $46.3 million for the year ended December 31, 1997 as compared with $31.7 million for the year ended December 31, 1996. The increase of $14.6 million reflects an increase of $19.7 million in depreciation and depletion on the oil and natural gas wells and facilities located on Viosca Knoll Block 817, Garden Banks Block 72 and Garden Banks Block 117 as a result of increased production from these leases which initiated production in December 1995, May 1996 and July 1996, respectively, offset by a decrease of $5.1 million in depreciation on pipelines, platforms and facilities.

Impairment, abandonment and other totaled $21.2 million for the year ended December 31, 1997 and consisted of a non-recurring charge to reserve our investment in certain gathering facilities and other assets associated with Tatham Offshore's Ewing Bank 914 #2 well and Ship Shoal Block 331 property, to accrue our abandonment obligations associated with the gathering facilities serving these properties, to reserve our noncurrent receivable related to the prepayment of the demand charge obligations under certain agreements related to the Ewing Bank and Ship Shoal leases and to accrue certain abandonment obligations associated with its oil and natural gas properties.

General and administrative expenses, including the management fee allocated from our general partner, totaled $14.7 million for the year ended December 31, 1997 as compared with $8.5 million for the year ended December 31, 1996. General and administrative expenses for the year ended December 31, 1996 were reduced by a one-time $1.4 million reimbursement from Poseidon as a result of our management of the initial construction of Poseidon. Excluding this one-time reimbursement by Poseidon, general and administrative expenses for the year ended December 31, 1997 increased $4.7 million as compared to the year ended December 31, 1996. This increase reflects (1) a $1.5 million increase in management fees allocated by our general partner to us as a result of our increased construction and operational activities, (2) a $3.6 million increase in our direct general and administrative expenses primarily related to the appreciation and vesting of unit appreciation rights granted to certain officers and employees in 1995, 1996 and 1997 and (3) a $0.4 million decrease in the reimbursement to El Paso Energy for certain tax liabilities pursuant to the management agreement with us.

Interest income and other totaled $1.5 million for the year ended December 31, 1997 as compared with $1.7 million for the year ended December 31, 1996.

Interest and other financing costs, excluding capitalized interest, for the year ended December 31, 1997 totaled $14.2 million as compared with $5.6 million for the year ended December 31, 1996. During the years ended December 31, 1997 and 1996, we capitalized $1.7 million and $11.9 million, respectively, of interest costs in connection with construction projects and drilling activities in progress during such periods. During the years ended December 31, 1997 and 1996, we had outstanding indebtedness averaging approximately $232.5 million and $181.4 million, respectively.

Net loss for the year ended December 31, 1997 totaled $1.1 million, or $0.06 per unit, as compared with net income of $38.7 million, or $1.57 per unit, for the year ended December 31, 1996 as a result of the items discussed above.

LIQUIDITY AND CAPITAL RESOURCES

SOURCES OF CASH. We intend to satisfy our capital requirements and other working capital needs primarily from cash on hand, cash from operations and borrowings under our revolving credit facility (discussed below). However, depending on market and other factors, we may issue additional equity to raise cash or acquire assets, as in the acquisition of the additional interest in Viosca Knoll. Net cash provided by operating activities for the year ended December 31, 1998 and for the six months ended June 30, 1999 totaled $25.7 million and $23.6 million, respectively. In addition to funds available under our credit facility or from the issuance of equity, we may use debt securities to raise cash to fund our working capital requirements. At June 30, 1999, we had cash and cash equivalents of $3.3 million.

Cash from operations is derived from (1) payments for gathering natural gas through our 100% owned pipelines, (2) platform access and production handling fees, (3) cash distributions from our joint ventures and (4) the sale of oil and natural gas attributable to our interest in our producing properties. Oil and natural gas properties are depleting assets and will produce reduced volumes of oil and natural gas in the future unless additional wells are drilled or recompletions of existing wells are successful. See "Business and Properties--Natural Gas and Oil Properties Associated with Infrastructure Opportunities" beginning on page 59 for current rates from our properties.

Our cash flows from operations will be affected by the ability of each of our joint ventures to make distributions. Distributions from such entities are also subject to the discretion of their respective management committees. Further, each of Stingray, Poseidon and Western Gulf is party to a credit agreement under which it has outstanding obligations that may restrict the payments of distributions to its owners. We received distributions from our joint ventures during the year ended December 31, 1998 and for the six months ended June 30, 1999 totaling $31.2 million and $24.1 million, respectively.

We entered into an indenture dated May 27, 1999, with Chase Bank of Texas, National Association, pursuant to which we issued $175 million in aggregate principal amount of Series A Senior Subordinated Notes (along with the indenture, the "subordinated notes"). The subordinated notes bear interest at a rate of 10 3/8% per annum, payable semi-annually on June 1 and December 1, mature on June 1, 2009, and are junior to substantially all of our other indebtedness other than trade payables and indebtedness that by its terms expressly states it is equal or junior to the subordinated notes. Generally, we do not have the right to prepay the subordinated notes prior to May 31, 2004, and thereafter, we may prepay the subordinated notes at a premium of 5% of the face amount, which premium declines ratably through maturity. Although the subordinated notes are unsecured, all of our subsidiaries have guaranteed those obligations. The subordinated notes contain customary terms and conditions, including various affirmative and negative covenants and the obligation to offer to repurchase the notes at a premium under certain circumstances. Among other things, the terms of the subordinated notes limit our ability to make distributions to our unitholders, redeem or otherwise reacquire any of our equity, incur additional indebtedness, incur or permit to exist certain liens, make additional investments, engage in transactions with affiliates, engage in certain types of business and dispose of assets under certain circumstances, including if certain financial tests are not satisfied or there is a default. In addition, we will be obligated to offer to repurchase the subordinated notes if we experience certain types of changes of control or if we dispose of certain assets and do not reinvest the proceeds or repay senior indebtedness.

We currently have a revolving credit facility providing for up to $375.0 million of available credit, subject to customary terms and conditions, including certain limitations on incurring additional indebtedness (including borrowings under this facility) if certain financial targets are not achieved and maintained. In addition, we will be required to prepay a portion of the balance outstanding under our credit facility to the extent such financial targets are not achieved and maintained. We may borrow money under the credit agreement for general partnership purposes, including financing capital expenditures, working capital requirements, and, subject to certain limitations, distributions to our unitholders. We may also utilize this credit facility to issue letters of credit as may be required from time to time; however, no letters of credit are currently outstanding. Concurrently with the closing of the offering of our subordinated notes, we amended our facility to, among other things, extend the maturity to May 2002 from December 1999. Our revolving credit facility is guaranteed by the general partner and each of our subsidiaries and is collateralized by (1) the management agreement between the general partner and a subsidiary of El Paso Energy, (2) substantially all of our assets and (3) the general partner's 1.0% general partner interest in us and approximate 1.0% nonmanaging interest in certain of our subsidiaries. Our revolving credit facility has no scheduled amortization prior to maturity. As of August 9, 1999, we had $300.0 million outstanding under our revolving credit facility bearing interest at an average floating rate of 7.7% per annum and approximately $44.5 million of funds are available under the facility. We used all otherwise unapplied proceeds from the offering of our subordinated notes (approximately $112.3 million) to reduce the balance outstanding under our credit facility.

Poseidon has a revolving credit facility with a syndicate of commercial banks to provide up to $150.0 million for other working capital needs of Poseidon. Poseidon's ability to borrow money under the facility is subject to certain customary terms and conditions, including certain limitations on incurring additional indebtedness (including borrowings under this credit facility) if certain financial targets are not achieved and maintained. In addition, Poseidon will be required to prepay a portion of the balance outstanding under this credit facility to the extent such financial targets are not achieved and maintained. The Poseidon credit facility has no scheduled amortization prior to maturity. The Poseidon credit facility is collateralized by a substantial portion of Poseidon's assets and matures on April 30, 2001. As of August 9, 1999, Poseidon had $140.0 million outstanding under its credit facility bearing interest at an average floating rate of 6.5% per annum and had approximately $10.0 million of additional funds available under the facility.

Stingray has an existing term loan agreement with a syndicate of commercial banks which matures on March 31, 2003. The agreement requires Stingray to make 18 quarterly principal payments of approximately $1.6 million commencing December 31, 1998. The term loan agreement is principally collateralized by current and future natural gas transportation contracts between Stingray and its customers. On the earlier to occur of March 31, 2003 or the accelerated due date pursuant to the Stingray credit agreement, if Stingray has not paid all amounts due under its credit agreement, we are obligated to pay the lesser of (1) $8.5 million, (2) the aggregate amount of distributions received by us from Stingray subsequent to January 1, 1998 or (3) 50.0% of any then outstanding amounts due pursuant to the Stingray credit agreement. We do not expect to have to pay any amount pursuant to this obligation. As of August 9, 1999, Stingray had $23.7 million outstanding under its term loan agreement bearing interest at an average floating rate of 6.3% per annum.

Western Gulf, which owns all of HIOS and East Breaks, entered into a revolving credit facility with a syndicate of commercial banks in February 1999 to provide up to $100.0 million for the construction of the East Breaks System and for other working capital needs of Western Gulf, East Breaks and HIOS. Western Gulf's ability to borrow money under the facility is subject to certain customary terms and conditions, including certain limitations on incurring additional indebtedness (including borrowings under this credit facility) if certain financial targets are not achieved and maintained. In addition, Western Gulf would be required to prepay a portion of the balance outstanding under this credit facility to the extent such financial targets are not achieved and maintained. The credit facility has no scheduled amortization prior to its maturity in February 2004. The Western Gulf credit facility is collateralized by substantially all of the material contracts and agreements of East Breaks and Western Gulf, including Western Gulf's ownership in HIOS and East Breaks, and supported by the guarantee of East Breaks. In addition, we have agreed to return up to $3.0 million in distributions paid to us by Western Gulf under certain circumstances. As of August 9, 1999, Western Gulf had $50.1 million outstanding under this credit facility bearing interest at a floating rate of 6.5% per annum and had approximately $49.9 million of additional funds available under this facility.

Prior to the closing of the offering of our subordinated notes, Viosca Knoll had a revolving credit facility with a syndicate of commercial banks to provide up to $100.0 million for other working capital needs of Viosca Knoll, which we repaid in full and terminated on June 1, 1999 in connection with our acquisition of an additional 49.0% in Viosca Knoll from El Paso Energy.

USES OF CASH. Our primary capital requirements are (1) quarterly distributions to holders of preference units and common units and to the general partner, including incentive distributions, as applicable, (2) expenditures for the maintenance of our pipelines and related infrastructure and the acquisition and construction of additional energy-related infrastructure, (3) expenditures related to our producing oil and natural gas properties, (4) expenditures relating to the development of our non-producing property, the Ewing Bank 958 Unit, (5) administrative expenses (including management fees) and other operating expenses, (6) contributions to our joint ventures as required to fund capital expenditures for new facilities and (7) debt service on our outstanding indebtedness, including reducing the balance outstanding under our revolving credit facility with approximately $91.6 million of proceeds from this offering.

During the year ended December 31, 1998 and the six months ended June 30, 1999, we paid distributions to our partners totaling $62.4 million and $31.3 million, respectively. In May 1999, we paid an incentive distribution of $2.8 million to the general partner. On July 19, 1999, we declared our second quarter cash distribution of $0.275 per preference unit and $0.525 per common unit covering the three months ended June 30, 1999. The distributions were paid on August 13, 1999 to all holders of record of common and preference units at the close of business on July 30, 1999 and included an incentive distribution to our general partner of $3.2 million. We believe that we will be able to continue to pay at least the current quarterly distributions of $0.275 per preference unit and $0.525 per common unit for the foreseeable future. At these distribution rates, the quarterly distributions total $17.4 million ($20.3 million assuming the issuance of at least 4,000,000 common units upon the consummation of this offering) in respect of the preference units, common units and general partner interest.

In April 1998, we completed the construction and installation of a new platform and production handling facilities at East Cameron Block 373 at a cost of $30.2 million, $9.4 million of which was incurred in 1998.

During 1998, we paid $2.9 million related to the abandonment of the Ewing Bank flowlines and $8.6 million to our management in connection with the accelerated vesting of certain rights granted under a compensation plan that was terminated in 1998.

Substantially all of the capital expenditures by Poseidon, East Breaks, Viosca Knoll and Stingray were funded by borrowings under credit facilities, and any future capital expenditures by East Breaks, Poseidon, HIOS and Stingray are anticipated to be funded by borrowings under credit facilities. Our capital expenditures (including construction and installation of the Allegheny oil pipeline and development costs of the Ewing Bank 958 Unit) and equity investments and acquisitions for the year ended December 31, 1998 and for the six months ended June 30, 1999 were $66.1 million and $92.8 million, respectively. We have in the past contributed existing assets to joint ventures as partial consideration for ownership interest therein and may in the future contribute existing assets, including cash, to new joint ventures as partial consideration for ownership interest.

Over the next twelve months, we expect our capital expenditures to range from $30.0 to $100.0 million, depending on the number and types of projects in which we participate and the level and nature of that participation. We currently are reviewing a large number of potential natural gas and oil pipeline, platform, development and other infrastructure opportunities with a total capital cost estimated at in excess of $200.0 million. We expect to pursue many of these projects (including some in which we currently own a 100% interest) through joint ventures, strategic alliances or other participatory arrangements. Often, we structure these joint ventures, in which we usually own an interest of 50% or less, so they may independently access capital, like non-recourse or limited recourse project financing.

We expect to make capital expenditures in connection with the maintenance of the service capabilities of our subsidiary owned natural gas and oil pipeline, platform, development and other infrastructure. We anticipate that these capital expenditures will aggregate approximately $1.5 million to $2.0 million per year (which generally will be funded from cash generated from operations), although the actual level of these capital expenditures may change from time to time for many reasons, some of which may be beyond our control.

Interest costs incurred by us totaled $19.2 million and $14.6 million, respectively, for the year ended December 31, 1998 and for the six months ended June 30, 1999. We capitalized $1.1 million and $0.8 million, respectively, of such interest costs in connection with construction projects and drilling activities in process during such periods.

We anticipate that our capital expenditures and equity investments for 1999 will relate to continuing acquisition, construction and development activities, including the completion of the Allegheny oil pipeline, the construction of the Nemo pipeline described in this prospectus and the development of the Ewing Bank 958 Unit. We anticipate funding such cash requirements primarily with available cash flow, borrowings under our credit facility and, depending on the capital requirements and related market conditions, issuing additional debt and/or equity. Further, with respect to the development of the Ewing Bank 958 Unit as currently planned, we anticipate consummating an exchange, sale, farmout, joint venture or similar arrangement to share in the drilling and infrastructure costs associated with that development. If we do not make such an arrangement, we will have to raise additional capital through another source or we will not be able to proceed with this development as currently planned. We cannot assure you that any such source of capital would be available to complete this development.

NEW ACCOUNTING STANDARDS

REPORTING ON THE COSTS OF START-UP ACTIVITIES. In April 1998, the American Institute of Certified Public Accountants issued Statement of Position 98-5, "Reporting on the Costs of Start-Up Activities." This statement defines start-up activities, requires start-up and organization costs to be expensed as incurred and requires that any such costs that exist on the balance sheet be expensed upon adoption of this pronouncement. We adopted the provisions of this statement on January 1, 1999, the impact of which was not material to our financial position or results of operations.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES. In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standard ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that entities recognize all derivative investments as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as a hedge transaction. For fair-value hedge transactions in which we are hedging changes in an asset's, liability's or firm commitment's fair value, changes in the fair value of the derivative instrument will generally be offset in the income statement by changes in the hedged item's fair value. For cash-flow hedge transactions, in which we are hedging the variability of cash flows related to a variable-rate asset, liability, or a forecasted transaction, changes in the fair value of the derivative instrument will be reported in other comprehensive income. The gains and losses on the derivative instrument that are reported in other comprehensive income will be reclassified as earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The ineffective portion of all hedges will be recognized in current-period earnings. This statement was amended by SFAS No. 137 issued in June 1999. The amendment defers the effective date of SFAS No. 133 to fiscal years beginning after June 15, 2000. We have not yet determined the impact that the adoption of SFAS No. 133 will have on our financial position or results of operations.

ACCOUNTING FOR CONTRACTS INVOLVED IN ENERGY TRADING AND RISK MANAGEMENT ACTIVITIES. In November 1998, the Emerging Issues Task Force ("EITF") reached a consensus on EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." EITF 98-10 requires energy trading contracts to be recorded at fair value on the balance sheet, with the changes in fair value included in earnings and is effective for fiscal years beginning after December 15, 1998. We adopted the provisions of EITF 98-10 effective January 1, 1999, the resulting impact of which did not have a material impact on our financial position or results of operations.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We may utilize derivative financial instruments for purposes other than trading to manage our exposure to movements in interest rates and commodity prices. In accordance with procedures established by our Board of Directors, we monitor current economic conditions and evaluate our expectations of future prices and interest rates when making decisions with respect to risk management.

INTEREST RATE RISK. We utilize both fixed and variable rate long-term debt. We are exposed to some market risk due to the floating interest rate under our credit facility. Under our credit facility, the remaining principal and the final interest payments are due in March 2002. As of August 9, 1999, indebtedness outstanding under our credit facility was $300.0 million at an average interest rate of 7.7% per annum. A 1 1/2% increase in interest rates could result in a $4.5 million annual increase in interest expense on the total existing principal balance. We are exposed to similar risk under the credit facilities and loan agreements entered into by our joint ventures. See "-- Liquidity and Capital Resources." We have determined that it is not necessary to participate in interest rate-related derivative financial instruments because we currently do not expect significant short-term increases in the interest rates charged under our credit facility or the various joint venture credit facilities and loan agreements.

COMMODITY PRICE RISK. We hedge a portion of our oil and natural gas production to reduce our exposure to fluctuations in the market prices thereof. We use commodity price swap transactions whereby monthly settlements are based on differences between the prices specified in the commodity price swap agreements and the settlement prices of certain futures contracts quoted on the New York Mercantile Exchange ("NYMEX") or certain other indices. We settle the commodity price swap transactions by paying the negative difference or receiving the positive difference between the applicable settlement price and the price specified in the contract. The commodity price swap transactions we use differ from futures contracts in that there are no contractual obligations which require or allow for the future delivery of the product. The credit risk from our price swap contracts is derived from the counter-party to the transaction, typically a major financial institution. We do not require collateral and do not anticipate non-performance by this counter-party, which does not transact a sufficient volume of transactions with us to create a significant concentration of credit risk. Gains or losses resulting from hedging activities and the termination of any hedging instruments are initially deferred and included as an increase or decrease to oil and natural gas sales in the period in which the hedged production is sold. For the six months ended June 30, 1999, we recorded a net loss of $0.7 million related to hedging activities.

As of June 30, 1999, we had open sales swap transactions for 10,000 MMbtu of natural gas per day for calendar 2000 at a fixed price to be determined at our option equal to the February 2000 Natural Gas Futures Contract on NYMEX as quoted at any time during 1999 and January 2000, to and including the last two trading days of the February 2000 contract, minus $0.5450 per MMbtu. Additionally, we had open sales swap transactions of 10,000 MMbtu of natural gas per day at a fixed price to be determined at our option equal to the January 2000 Natural Gas Futures Contract on NYMEX as quoted at any time during 1999, to and including the last two trading days of the January 2000 contract, minus $0.50 per MMbtu.

At June 30, 1999, we had open crude oil hedges on approximately 500 barrels per day for the remainder of calendar 1999 at an average price of $16.10 per barrel.

If we had settled our open natural gas hedging positions as of June 30, 1999 based on the applicable settlement prices of the NYMEX futures contracts, we would have recognized a loss of approximately $2.2 million.

YEAR 2000

The Year 2000 issue is the result of computer programs that were written using two digits rather than four to define the year. We have established a project team that works with the El Paso Energy executive steering committee to coordinate the phases of our Year 2000 project to ensure that our key automated systems and related processes will remain functional through Year 2000. Those phases include: (1) awareness, (2) assessment, (3) remediation, (4) testing, (5) implementation of the necessary modifications and (6) contingency planning (which was previously included as a component of our implementation phase). We have hired outside consultants and are involved in several industry trade-groups to supplement our project team.

The awareness phase recognizes the importance of Year 2000 issues and its potential impact on us. Through the project team, we have established an awareness program which includes participation of management in each business area. The awareness phase is substantially completed, although we will continually update awareness efforts for the duration of the Year 2000 project.

The assessment phase consists of conducting an inventory of our key automated systems and related processes, analyzing and assigning levels of criticality to those systems and processes, identifying and prioritizing resource requirements, developing validation strategies and testing plans, and evaluating business partner relationships. We estimate that we are more than three-quarters complete with the portion of the assessment phase to determine the nature and impact of the Year 2000 date change for hardware and equipment, embedded chip systems, and third-party developed software. The assessment phase of the project involves, among other things, efforts to obtain representations and assurances from third parties, including joint ventures, partners, customers and vendors, that their hardware and equipment products, embedded chip systems and software products being used by or impacting us are or will be modified to be Year 2000 compliant. To date, the responses from such third parties, although generally encouraging, are inconclusive. Although we intend to interact only with those third parties that have Year 2000 compliant computer systems, it is impossible for us to monitor all such systems. As a result, we cannot predict the potential consequences if our joint ventures, partners, customers or vendors are not Year 2000 compliant. We are currently evaluating the exposure associated with such business partner relationships.

The remediation phase involves converting, modifying, replacing or eliminating selected key automated systems identified in the assessment phase. The testing phase involves the validation of the identified key automated systems. We are utilizing test tools and written procedures to document and validate, as necessary, its unit, system, integration and acceptance testing. The implementation phase involves placing the converted or replaced key automated systems into operations. In some cases, the implementation phase will also involve the implementation of contingency plans needed to support business functions and processes that may be interrupted by Year 2000 failures that are outside our control. As of August 9, 1999, we are substantially completed with each phase.

The contingency planning phase consists of developing a risk profile of our critical business processes and then providing for actions we will pursue to keep such processes operational in the event of Year 2000 disruptions. The focus of such contingency planning is on prompt response to Year 2000 events, and a plan for subsequent resumption of normal operations. The plan is expected to assess the risk of significant failure to critical processes performed by us, and to address the mitigation of those risks. The plan will also consider any significant failures in the event the most reasonably likely worst case scenario develops, as discussed below. In addition, the plan is expected to factor in the severity and duration of the impact of a significant failure. As of August 9, 1999, the contingency plan was substantially completed. This Year 2000 contingency plan will continue to be modified and adjusted through the year as additional information from key external business partners becomes available.

Our goal is to ensure that all of our critical systems and processes that are under our direct control remain functional. However, certain systems and processes may be interrelated with or dependent upon systems outside our control and systems within our control may have unpredicted problems. Accordingly, there can be no assurance that significant disruptions will be avoided. Our present analysis of our most reasonably likely worst case scenario for Year 2000 disruptions includes Year 2000 failures in the telecommunications and electricity industries, as well as interruptions from suppliers that might cause disruptions in our operations, thus causing temporary financial losses and an inability to meet our obligations to customers. A significant portion of the oil and natural gas transported through our pipelines is owned by third parties. Accordingly, failures of the producers of oil and natural gas to be ready for the Year 2000 could significantly disrupt the flow of the hydrocarbons for customers. In many cases, the producers have no direct contractual relationship with us, and we rely on our customers to verify the Year 2000 readiness of the producers from whom they purchase oil and natural gas. A portion of our revenue for the transportation of oil and natural gas is based upon fees paid by our customers for the reservation of capacity and a portion of the revenue is based upon the volume of actual throughput. As such, short-term disruptions in throughput caused by factors beyond our control may have a financial impact on us and could cause operational problems for our customers. Longer-term disruptions could materially impact our operations, financial condition and cash flows.

We estimate that the costs to be incurred in 1999 and 2000 associated with assessing, remediating and testing hardware and equipment, embedded chip systems, and third-party developed software will not exceed $1.0 million, all of which will be expensed. As of June 30, 1999, we had incurred less than $0.1 million related to such costs. We have previously only tracked incremental expenses related to our Year 2000 project. The costs of the Year 2000 project related to salaried employees of El Paso Energy, including their direct salaries and benefits, are not available and have not been included in the estimated costs of the project. The management fee charged to us by the general partner includes such incremental expenses.

Presently, we intend to reassess our estimate of Year 2000 costs in the event we complete an acquisition of, or make a material investment in, substantial facilities or another business entity.

Management does not expect the costs of our Year 2000 project will have a material adverse effect on our financial position, results of operations or cash flows. However, based on information available at this time, we cannot conclude that disruption caused by internal or external Year 2000 related failures will not adversely effect us. Specific factors which may affect the success of our Year 2000 efforts and the frequency or severity of Year 2000 disruption or amount of any expense include failure by us or our outside consultants to properly identify deficient systems, the failure of the selected remedial action to adequately address the deficiencies, the failure by us or our outside consultants to complete the remediation in a timely manner (due to shortages of qualified labor or other factors), the failure of other parties to joint ventures in which we are involved to meet their obligations, both financial and operational under the relevant joint venture agreements to remediate assets used by the joint venture, unforeseen expenses related to the remediation of existing systems or the transition to replacement systems, and the failure of third parties, including joint ventures, to become Year 2000 compliant or to adequately notify us of potential noncompliance.

The above disclosure is a "Year 2000 Readiness Disclosure" made with the intention to comply fully with the Year 2000 Information and Readiness Disclosure Act of 1998, Pub. L. No. 105-271, 112 Stat, 2386, signed into law October 19, 1998. All statements made herein shall be construed within the confines of the Act. To the extent that any reader of this Year 2000 Readiness Disclosure is other than an investor or potential investor in our or an affiliate's equity or debt securities, this disclosure is made for the sole purpose of communicating or disclosing information aimed at correcting, helping to correct and/or avoiding Year 2000 failures.

BUSINESS AND PROPERTIES

OVERVIEW

We are a provider of integrated energy services, including natural gas and oil gathering, transportation, midstream and other related services in the Gulf of Mexico. We commenced operations in 1989, through a predecessor company, with the objective of becoming a major natural gas gatherer and transporter in the Gulf of Mexico, with specific focus on the emerging Deepwater, and identifying and exploiting other energy-related opportunities. When we completed our initial public offering in 1993, we owned interests in seven pipeline systems, which extended approximately 721 miles and had a design capacity of 5.0 Bcf of natural gas per day. Either directly or through joint ventures, we now own interests in nine operating pipeline systems, which extend approximately 1,500 miles and have a design capacity of 6.8 Bcf of natural gas and 400,000 barrels of oil per day. We also own multi-purpose platforms; production handling, dehydration and other energy-related infrastructure facilities; as well as oil and natural gas properties. We have substantial assets in the Gulf of Mexico, primarily offshore Louisiana and Mississippi, which we believe are well-positioned to maintain a stable base level of operations and to provide growth opportunities by successfully competing for new production in our areas of service, especially those assets in the Deepwater (water depths greater than 1,500 feet) and Flextrend (water depths of 600 to 1,500 feet) regions. Either directly or through joint ventures, we own interests in:

- eight offshore natural gas pipeline systems;

- one offshore crude oil gathering system;

- six strategically-located, multi-purpose offshore platforms that serve to interconnect the pipeline grid;

- production handling and dehydration facilities; and

- four oil and natural gas properties associated with infrastructure opportunities.

In addition, with our joint venture partners, we are constructing two natural gas pipelines through newly created joint ventures, East Breaks Gathering Company, L.L.C. and Nemo Gathering Company, LLC, and we have recently completed the construction of a wholly owned oil pipeline which we expect to become operational in the fourth quarter of 1999, the Allegheny System.

In the past six years, our operations have grown through the acquisition and construction of energy-related infrastructure, including:

- acquiring all of the Manta Ray system and constructing and acquiring a 50.0% interest in the Viosca Knoll system in 1994;

- constructing two multi-purpose platforms located at Viosca Knoll Block 817 and Garden Banks Block 72 in 1995;

- acquiring, developing and producing oil and natural gas reserves located in the Gulf of Mexico in 1995;

- completing construction in 1996 of the Poseidon system, a crude oil pipeline system in which we own a 36.0% working interest;

- acquiring in 1997 an effective 25.7% interest in each of Nautilus and Manta Ray Offshore, to which we contributed substantially all of the Manta Ray system (originally acquired during a period from 1992);

- constructing a multi-purpose platform located in East Cameron Block 373 and acquiring a 100% working interest in the Ewing Bank 958 Unit in 1998; and

- acquiring in 1999 an additional 49.0% interest in the Viosca Knoll system, an additional indirect 33.3% interest in UTOS and an additional indirect (through Western Gulf) 20.0% interest in HIOS and East Breaks.

In addition to our wholly owned assets and operations, we conduct a large portion of our business through joint ventures/strategic alliances, which we believe are ideally suited for Deepwater operations. We use joint ventures to reduce our capital requirements and risk exposure to individual projects, as well as to develop strategic relationships, realize synergies resulting from combining resources, and benefit from the assets, experience and resources of our partners. Generally, our partners are integrated or very large independent energy companies with substantial interests, operations and assets in the Gulf of Mexico, including affiliates of Coastal/ANR, Equilon, Marathon, Shell and Texaco.

Through our strategically-located network of wholly owned and joint venture pipelines and other facilities and businesses, we believe we provide customers with an efficient and cost effective midstream alternative. Today, we offer some customers a unique single point of contact through which they may access a wide range of integrated or independent midstream services, including gathering, transportation, production handling, dehydration and other services. We also provide producers operating in certain Deepwater and Flextrend areas with relatively low-cost access to numerous onshore long-haul pipelines and, accordingly, multiple end-use markets. Additionally, our Deepwater experience and specialized expertise in this area allows us to provide operational solutions to producers looking for economic improvements in their development activities.

INDUSTRY OVERVIEW

We believe that development and exploration activity in the Gulf of Mexico will continue and that the Gulf of Mexico will continue to be one of the most prolific producing regions in the U.S. Today, the Gulf of Mexico accounts for approximately 20.3% and 25.6% of total U.S. production of oil and natural gas, respectively. Oil production from the Gulf of Mexico is expected to increase from 1.3 MMbbls/d in 1998 to 1.8 MMbbls/d in 2003, according to the Potential Gas Committee, which is comprised of academic institutions, government agencies and industry participants. That committee also expects production of natural gas to increase from 14.0 Bcf/d in 1998 to 16.6 Bcf/d in 2003. The principal source of this production growth is expected to be the Flextrend and Deepwater. Recent developments in oil and natural gas exploration and production techniques, such as 3-D seismic analysis, horizontal drilling, remote subsea completions via satellite templates and sea floor wellheads, and non-stationary surface production facilities, have substantially reduced finding, development and production costs allowing operators to move into the Deepwater regions of the Gulf of Mexico. For instance, the number of blocks under lease in the Gulf of Mexico in water depths greater than 600 feet has increased from approximately 3,100 in February 1998 to approximately 4,200 in February 1999. By year-end 2003, production from deeper water fields is projected to account for 54.6% and 24.0% of the Gulf of Mexico's oil and natural gas production, respectively, up from 35.6% and 13.4% in 1998, respectively, according to the Potential Gas Committee.

We have pipelines, platforms and other infrastructure facilities strategically positioned throughout a large portion of the Flextrend area of the Gulf of Mexico, offshore Louisiana and Mississippi and extending out to and, in some areas, into the Deepwater. Because of their location in relation to the way in which oil and natural gas development has occurred in the Gulf of Mexico, we expect these assets to contribute significantly to the development of natural gas and oil in surrounding areas of the Flextrend and Deepwater. Historically, development of nascent Gulf of Mexico regions has started with large pipelines positioned in a north/south direction connecting new, significant discoveries to existing shoreward infrastructure. Then, additional infrastructure has expanded laterally in an east/west direction to access reserves between the north/south pipelines. As this pipeline infrastructure became more accessible to more producing regions, the incremental cost of placing reserves on production declined, which facilitated the development of projects that could not support the installation of pipelines on a stand-alone basis. This process of lateral expansion has been continually repeated as advances in exploration and development technology have allowed producers to economically explore for oil and natural gas in progressively deeper water areas. We believe that the exploration and development of the deeper water areas will accelerate in the future and, as a result, will continue to provide attractive opportunities for companies strategically positioned to access production in those areas.

In part because of the technological advancements and the expanded pipeline infrastructure, the Gulf Coast was the only part of the United States to see an increase in potential natural gas supplies in the last two years, while total U.S. natural gas supplies have declined over that same period, according to the Potential Gas Committee. That committee also projects that the Gulf Coast natural gas resource base, including proved reserves, increased from 264.9 trillion cubic feet to 265.5 trillion cubic feet during 1998; thus, the Gulf was the only major producing region in the U.S. which replaced more reserves than were produced in 1998. Construction by us and others of the pipeline infrastructure necessary to deliver this production to onshore markets is expected to remain critical to the expansion and development efforts in these deeper water regions.

We believe that we are strategically positioned to take advantage of new discoveries and increased production in the Deepwater, Flextrend and subsalt regions of the Gulf of Mexico. In addition to comprising a significant portion of the network of pipelines in the shallow waters of the Gulf of Mexico off of Louisiana, our pipelines also have substantial east/west facilities on the edge of portions of the Flextrend and deeper water. We also have several existing and planned extensions into the deeper water regions. However, we cannot assure you that additional reserves in those areas will actually be developed or, if developed, that any of our pipelines will gather, transport or otherwise handle that production.

BUSINESS STRATEGY

Our strategically-positioned assets, as well as our knowledge and expertise, enhance our ability to capitalize on infrastructure and other energy-related business opportunities in the Gulf of Mexico, particularly in the deeper water regions. By implementing the following business strategies, we expect to maintain our position as a provider of integrated energy services, including natural gas and oil gathering, transportation, midstream and other related services in the Gulf of Mexico.

- FOCUS ON HIGH POTENTIAL DEEPWATER.

  We believe Deepwater operations will provide us with significantly greater profit opportunities for a number of reasons. First, our existing assets are well-positioned for expansion into the Deepwater. Because of the location of certain of our assets, we believe such expansion projects can be implemented at a lower cost relative to our competition, thus enhancing our goal of being a low-cost provider of gathering, transportation, production handling and other midstream services. Second, Deepwater projects require large capital investment by producers and, in return, produce substantial reserves and cash flow, when successful. Given the significant return potential, such projects are undertaken with a longer-term view toward the commodity cycle and are substantially less sensitive to near-term oil and natural gas prices. Therefore, by focusing on Deepwater projects we expect to increase the stability of our operations and financial results.

- PROVIDE MULTIPLE MARKET ACCESS FOR GULF OF MEXICO PRODUCTION.

  Unlike some of our competitors, we connect to numerous onshore, long-haul pipelines and can offer producers access to multiple end-use markets. Our ability to provide multiple pipeline connections and broad market access is important, because it allows producers to take advantage of pricing differentials, mitigate capacity constraints and avoid temporary suspensions of service.

- OFFER A SINGLE SOURCE ALTERNATIVE FOR A COMPLETE RANGE OF MIDSTREAM SERVICES.

  Through our strategically-located network of wholly owned and joint venture pipelines, other facilities and businesses, we offer some customers a unique single point of contact through which they may access a wide range of midstream services and assets, including (1) gathering, transportation, production handling, dehydration, compression, pumping and other handling services for both natural gas and oil, (2) access to platforms, compression and other infrastructure facilities, (3) significant Flextrend and Deepwater experience and expertise, and (4) other related assets and services. Under the more conventional system used by many of our competitors, producers must contact and negotiate with a number of unaffiliated parties, including natural gas pipelines, oil pipelines, processors and other service providers, with potentially competing interests. By providing a complete range of services between the wellhead and the shore, we believe we provide producers with a more efficient midstream solution, which should result in increased revenue opportunities.

- SHARE CAPITAL COSTS AND RISKS WITH STRATEGIC JOINT VENTURE PARTNERS.

Given the significant cost to expand energy-related infrastructure in the Flextrend and Deepwater areas of the Gulf of Mexico, we seek opportunities to undertake such projects through joint ventures or partnerships, principally with partners with substantial financial resources and substantial strategic interests, assets and operations, especially in the Deepwater, Flextrend and subsalt regions of the Gulf of Mexico. By forming such joint ventures or partnerships, we reduce our capital requirements, mitigate our risk exposure to individual projects, develop strategic business relationships with other industry participants and benefit from the assets, experience and resources of our partners. Generally, our partners are integrated or very large independent energy companies with substantial interests, operations and assets in the Gulf of Mexico, including affiliates of Coastal/ANR, Equilon, Marathon, Shell and Texaco.

- DESIGN NEW INFRASTRUCTURE PROJECTS BASED ON DEDICATED PRODUCTION UNDER LONG-TERM COMMITMENTS AND/OR FIXED PAYMENT ARRANGEMENTS WITH THE ABILITY TO EXPAND CAPACITY AND SERVICES IN THE FUTURE TO CAPTURE POTENTIAL GROWTH OPPORTUNITIES.

We base decisions to construct new infrastructure on both firm long-term dedication agreements (and/or fixed payment arrangements) and our assessment of potential production in the vicinity of the dedication. This strategy allows us to recover our initial investment and receive a base return through a stable, predictable source of cash flow. We also often design our new pipeline, platform, production handling and other hydrocarbon handling facilities with additional capacity and with the flexibility to expand capacity or provide additional services, as required. For example, we may design a platform to allow it to act as a pipeline landing and maintenance hub or to facilitate drilling and development activities. Although this approach increases the original cost of the asset, we believe that such capacity and flexibility allows us to more effectively compete for new production and to lower the overall cost of our services.

- SELECTIVELY INVEST IN OIL AND NATURAL GAS PROPERTIES ASSOCIATED WITH INFRASTRUCTURE OPPORTUNITIES.

In areas we serve or desire to serve, we pursue opportunistic investments in pipelines, platforms, production handling facilities and other infrastructure assets, as well as selective investment in oil and natural gas properties. By providing infrastructure to previously unserved geographic regions, we can accelerate the development of oil and natural gas properties in that area. The ability to access common facilities allows producers to share the high fixed costs associated with infrastructure and, in certain circumstances, results in the economic development of otherwise marginal reserves and in an increase in the total reserves produced from that region. Further, we will invest in oil and natural gas properties when such investment will augment the utilization of our existing assets or lead to a strategic infrastructure opportunity.

RECENT DEVELOPMENTS, ACQUISITIONS AND NEW PROJECTS

WE FORMED A NEW NATURAL GAS DEEPWATER PIPELINE JOINT VENTURE WITH AN AFFILIATE OF SHELL. On August 10, 1999, we formed Nemo Gathering Company, LLC, a joint venture owned 66.1% by Tejas Offshore Pipeline, LLC and 33.9% by us, to construct, own and operate a natural gas gathering system. The Nemo System will deliver natural gas production from the Shell-operated Brutus and Glider Deepwater development properties to another of our joint venture pipelines, the Manta Ray Offshore

Gathering System. We expect the Nemo System to be placed in service in late 2001 at a total cost of approximately $36.0 million.

WE INCREASED OUR OWNERSHIP INTEREST IN THREE OF OUR EXISTING PIPELINE JOINT VENTURES--UTOS, HIOS AND EAST BREAKS, WHICH IS A NEW DEEPWATER EXPANSION. In December 1998, the partners of HIOS, a Delaware partnership then owned 40.0% by us, 40.0% by subsidiaries of ANR Pipeline Company and 20.0% by a subsidiary of NGPL, restructured the joint venture arrangement by (1) creating a holding company named Western Gulf Holdings, L.L.C., (2) converting HIOS, which owns a regulated natural gas pipeline located in the Gulf of Mexico, into a limited liability company named High Island Offshore System, L.L.C., and (3) forming a new limited liability company named East Breaks Gathering Company, L.L.C. to construct and operate an unregulated natural gas pipeline system. Western Gulf owns 100% of each of HIOS and East Breaks.

On June 30, 1999, we increased our ownership interest in these three complementary, interconnecting natural gas pipeline systems located offshore Louisiana and the eastern portion of Texas. Through our acquisition of several companies from NGPL for approximately $51.0 million, we increased our ownership interest in UTOS to 66.7% from 33.3%, in HIOS to 60.0% from 40.0%, and in the East Breaks System to 60.0% from 40.0%. UTOS is a 30-mile pipeline extending from onshore Louisiana to a point of interconnection with HIOS, and receives substantially all of its throughput from HIOS for redelivery to an onshore production handling facility. HIOS is an expansive 204-mile pipeline system extending through the Flextrend and up to the Deepwater in our service areas. The East Breaks System is an 85-mile expansion currently under construction that will connect HIOS to the Diana and Hoover fields being developed by subsidiaries of Exxon and BP Amoco. Both Exxon and BP Amoco recently committed to the East Breaks System production from their Diana and Hoover properties. These two Deepwater properties are located in over 4,800 feet of water. With a throughput capacity of 400.0 MMcf per day of natural gas and the ability to expand its throughput capacity further, the East Breaks System and, therefore, the HIOS and UTOS systems have the ability to compete to gather and transport the substantial reserves associated with properties being, and expected to be, developed in these Deepwater frontier regions. We estimate that construction of the East Breaks System should be completed late in 2000 at a total cost of approximately $90.0 million.

WE ARE CONSTRUCTING A DEEPWATER PLATFORM IN CONNECTION WITH THE DEVELOPMENT OF OUR EWING BANK 958 UNIT. We believe our Ewing Bank 958 Unit development project, formerly known as the Sunday Silence Property, provides us with an opportunity to apply to the Deepwater area several strategies we have successfully implemented in the shallow and Flextrend areas. Similar to three other oil and natural gas properties we have developed, this project is associated with other independent infrastructure opportunities. Although the Ewing Bank 958 Unit development is a stand-alone project, we expect it to position us to play a significant role in the extension of pipeline, platform and other infrastructure facilities and service opportunities in this potential emerging Deepwater region. Currently, we anticipate building gathering extensions off of our Poseidon oil pipeline joint venture and our Manta Ray Offshore Gathering natural gas pipeline joint venture.

Pursuant to our current plan of development for the Ewing Bank 958 Unit, we are constructing a Moses Tension Leg Platform from which we would conduct all activities related to that development, including additional drilling, maintenance, and separation and handling operations. This platform is designed for use in water depths of up to 6,000 feet and will have production handling facilities with a throughput design capacity of 55.0 MMcf of natural gas per day and 25,000 barrels of oil per day.

To date there has been no production from the Ewing Bank 958 Unit. We currently own a 100% working interest in our Ewing Bank 958 Unit, which we purchased in October 1998 from a wholly owned, indirect subsidiary of El Paso Energy for $12.2 million. The Ewing Bank 958 Unit is located in approximately 1,500 feet of water and has received a royalty abatement from the MMS for the first 52.5 MMbbls of oil equivalent to be produced from the field. In addition to the initial discovery well drilled in 1994 and the two delineation wells drilled in 1994 and 1998, the Ewing Bank 958 Unit development program may require drilling up to five additional wells, depending on the level of actual production and other factors. As with many of our strategic assets, we continually evaluate various alternatives for the Ewing Bank 958 Unit and the related infrastructure, including joint ventures, strategic alliances and other business arrangements. If we do not consummate such an arrangement, we may need to raise substantial amounts of additional capital to fund this development project.

WE HAVE CONSTRUCTED OUR ALLEGHENY OIL PIPELINE TO DELIVER CRUDE OIL FROM THE FLEXTREND AND DEEPWATER REGIONS TO OUR POSEIDON JOINT VENTURE. We recently completed construction of the Allegheny oil pipeline, a 100% owned, 40 mile long crude oil pipeline that will connect British Borneo's Allegheny Field in the Green Canyon area of the Gulf of Mexico with our Poseidon oil pipeline joint venture. British Borneo has committed to the Allegheny System production from its Allegheny Field. The Allegheny System, which will have a daily capacity of more than 80,000 barrels of oil per day, is scheduled to begin operating during the fourth quarter of 1999. We estimate the construction and tie-in costs for the Allegheny oil pipeline to total approximately $27.0 million, $22.8 million of which was incurred prior to June 30, 1999.

WE INCREASED OUR OWNERSHIP INTEREST IN OUR VIOSCA KNOLL JOINT VENTURE, A NATURAL GAS PIPELINE LOCATED PRIMARILY IN THE FLEXTREND WATERS. On June 1, 1999, we acquired an additional 49.0% interest in Viosca Knoll Gathering Company from a subsidiary of El Paso Energy, which resulted in us owning 99.0% of Viosca Knoll with an option to purchase the remaining 1.0%. At the closing of the Viosca Knoll transaction, El Paso Energy contributed approximately $33.4 million in cash to Viosca Knoll, which equaled 50.0% of the principal amount outstanding under Viosca Knoll's credit facility, and we thereafter repaid and terminated that credit facility. We paid El Paso Energy $79.7 million for the 49.0% interest, comprised of approximately $19.9 million in cash and $59.8 million in our common units. We formed the Viosca Knoll joint venture in 1994 with a subsidiary of Tenneco Inc. to construct and operate a 125 mile long pipeline system, with an initial throughput capacity of 400.0 MMcf of natural gas per day, in an emerging producing region with limited infrastructure. The system design involved the construction of our first multi-purpose hub-platform and included the ability to expand throughput capacity at relatively nominal costs. Due to customer needs, including some recent Deepwater commitments, we have completed two expansion projects. These expansions more than doubled the Viosca Knoll System's capacity to 1.0 Bcf per day. The Viosca Knoll System provides its customers access to interstate pipelines of, among others, El Paso Energy, Columbia Gulf Transmission Company, Sonat, Transco and Destin Pipeline Company.

NATURAL GAS AND OIL PIPELINE SYSTEMS

GENERAL. We conduct a significant portion of our business activities through joint ventures, currently organized as general partnerships or limited liability companies, with subsidiaries of other substantial energy companies, including Marathon, Shell, Texaco, Coastal/ANR, KN Energy/NGPL and El Paso Energy. These joint ventures include Stingray and UTOS, both of which are partnerships, and Manta Ray Offshore, HIOS, Poseidon, Nautilus, East Breaks and West Cameron Dehydration, all of which are limited liability companies. Management decisions related to the joint ventures are made by management committees comprised of representatives of each partner or member, as applicable, with authority appointed in direct relationship to ownership interests.

Through our operating subsidiaries and our joint ventures, we own interests in eight operating natural gas pipeline systems, strategically located offshore Texas, Louisiana and Mississippi, which handle natural gas for producers, marketers, pipelines and end-users for a fee. Our natural gas pipelines include over 1,200 miles of pipeline with a throughput capacity of approximately 6.8 Bcf of natural gas per day. During the years ended December 31, 1998, 1997 and 1996, the natural gas pipelines handled an average of approximately 3.2 Bcf, 2.7 Bcf and 2.7 Bcf, respectively, of natural gas per day. Each of our natural gas pipelines interconnects with one or more long-line transmission pipelines that provide access to multiple markets in the eastern half of the United States. In addition, our East Breaks System, which has a design capacity of approximately 400.0 MMcf of natural gas per day, is being constructed and is expected to be placed in service in late-2000. Our HIOS system is expected to be the primary beneficiary of the East Breaks volumes.

None of our natural gas pipelines functions as a merchant to purchase and resell natural gas, thus avoiding the commodity risk associated with the purchase and resale of natural gas. Each of Nautilus, Stingray, HIOS and UTOS is currently classified as a "natural gas company" under the Natural Gas Act of 1938, as amended (the "NGA"), and is therefore subject to regulation by the FERC, including regulation of rates. None of Manta Ray Offshore, Viosca Knoll, Green Canyon Pipe Line Company, L.L.C., Ewing Bank Gathering Company, L.L.C., East Breaks, or Tarpon Transmission Company is currently, nor is East Breaks expected to be, considered a "natural gas company" under the NGA.

We own a 36.0% interest in the Poseidon oil pipeline, a major sour crude oil pipeline system that was built in response to an increased demand for additional sour crude oil pipeline capacity in the central Gulf of Mexico. Poseidon was constructed and placed in service in three separate phases. Today, Poseidon has a maximum design capacity of 400.0 Mbbls of oil per day. During 1998, 1997 and 1996, the Poseidon oil pipeline transported an average of approximately 97.5 Mbbls, 52.0 Mbbls and 30.0 Mbbls, respectively, of oil per day. During April 1999, this system averaged 170.0 Mbbls of oil per day. We expect Poseidon's throughput to increase substantially in the next several years as development progresses on the significant proved properties committed to that system.

Our network of subsidiary and joint venture owned natural gas and crude oil pipelines described in the following table provides our customers with gathering and transportation services and relatively low-cost access to multiple end-use markets. Our pipeline and infrastructure network currently extends from the shoreline, through the Flextrend, and up to and, in some areas, into the Deepwater in certain areas offshore Louisiana, Texas and Mississippi. We currently operate all of our subsidiary owned pipelines (Green Canyon, Tarpon, Viosca Knoll and Allegheny when operational later this year), and we are scheduled to become the operator of the Stingray system on or before October 1, 1999. Our remaining joint venture pipelines are operated by unaffiliated companies. In addition, we are constructing two natural gas pipelines through two newly created joint ventures, East Breaks Gathering Company, L.L.C. and

Nemo Gathering Company, LLC, and we have recently completed the construction of, and are waiting to connect, a wholly owned oil pipeline, the Allegheny System.

PIPELINE SYSTEM	OWNERSHIP INTEREST	JV PARTNERS (OPERATOR BOLD)	IN-SERVICE DATE	CAPACITY(1)	AGGREGATE MILES OF PIPELINE	AVERAGE THROUGHPUT(1) FOR THE YEAR ENDED DECEMBER 31, 1998 GROSS	1998 NET(2)	1997 GROSS	1997 NET(2)	TYPE(3)
Green Canyon.........	100.0%	LEVIATHAN	1990	220	68	126	126	148	148	U
Tarpon...............	100.0%	LEVIATHAN	1978	80	40	63	63	50	50	U
Viosca Knoll.........	99.0%(4)	LEVIATHAN El Paso Energy	1994	1,000(5)	125	570	285(6)	388	194(6)	U
UTOS.................	66.7%	Leviathan, ANR PIPELINE	1978	1,200	30	479	159(7)	316	105(7)	R
HIOS.................	60.0%	Leviathan, ANR PIPELINE	1977	1,800	204	842	337(8)	880	352(8)	R
Stingray.............	50.0%	LEVIATHAN, NGPL	1975	1,120	417	658	329	706	353	R
Manta Ray Offshore(9).........	25.7%	Leviathan, Marathon, SHELL	1987/88/97	755	225	281	72	195(10)	195(10)	U
Nautilus.............	25.7%	Leviathan, MARATHON, Shell	1997	600	101	153	39	--(11)	--(11)	R
Poseidon.............	36.0%	Leviathan, TEXACO/EQUILON PIPELINE CO., Marathon	1996	400	314	97	35	52(12)	19(12)	U

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(1) Measured in MMcf except for Poseidon, which is measured in Mbbls per day.
(2) Represents throughput net to our interest.
(3) U -- unregulated; R -- regulated. Regulated pipelines are subject to extensive rate regulation by the FERC under the Natural Gas Act.
(4) We expect to acquire the remaining 1.0% interest in Viosca Knoll from El Paso Energy after June 1, 2000.
(5) The original maximum design capacity of the Viosca Knoll system was 400.0 MMcf of natural gas per day. In 1996, Viosca Knoll installed a 7,000 horsepower compressor on our Viosca Knoll Block 817 platform to allow the Viosca Knoll system to increase its throughput capacity to approximately 700.0 MMcf of natural gas per day. In 1997, Viosca Knoll added approximately 25 miles of parallel 20-inch pipelines, increasing its throughput capacity to approximately 1.0 Bcf of natural gas per day.
(6) Represents throughput net to our 50.0% ownership interest during such period.
(7) Represents throughput net to our 33.3% ownership interest during such period.
(8) Represents throughput net to our 40.0% ownership interest during such period.
(9) In January 1997, we contributed substantially all of the Manta Ray Gathering system (approximately 160 miles of pipeline) to Manta Ray Offshore, decreasing our ownership in this system from 100% to an effective 25.7%. We continue to own and develop 19 miles of oil pipeline which were formerly a part of the Manta Ray Gathering system.
(10) Represents throughput specifically allocated to us by Manta Ray Offshore during the initial year of operations.
(11) The Nautilus system was placed in service in late December 1997.
(12) The Poseidon oil pipeline was placed in service in three phases, in April 1996, December 1996 and December 1997.

GREEN CANYON SYSTEM. The Green Canyon System, 100% owned and operated by us, is an unregulated natural gas transmission system consisting of approximately 68 miles of 10- to 20-inch diameter offshore pipeline which transports natural gas from the South Marsh Island, Eugene Island, Garden Banks and Green Canyon areas in the Gulf of Mexico to the west leg of the South Lateral owned by Transcontinental Gas Pipe Line Corporation ("Transco") for transportation to shore in eastern Louisiana.

TARPON SYSTEM. The Tarpon System, 100% owned and operated by us, is an unregulated natural gas transmission facility consisting of approximately 40 miles of 16-inch diameter offshore pipeline that extends from the Ship Shoal Block 274, South Addition, to the Eugene Island Area, South Addition, in an area of the Gulf of Mexico adjacent to the Green Canyon System.

MANTA RAY OFFSHORE SYSTEM. The Manta Ray Offshore System, indirectly owned 25.7% by us, 50.0% by Tejas Offshore Pipelines (a subsidiary of Shell) and 24.3% by Marathon Oil Company, is an unregulated natural gas transmission system consisting of (1) three separate gathering lines, all located offshore Louisiana in the Gulf of Mexico, which consist of a total of 76 miles of 12- to 24-inch diameter pipeline, each interconnecting offshore with the east leg of the Transco's Southeast Louisiana Lateral, which provides transportation for natural gas to shore in eastern Louisiana, (2) approximately 51 miles of dual 14- and 16-inch diameter pipelines, with the 16-inch pipeline extending from Green Canyon Block 29 and the 14-inch pipeline extending from South Timbalier Block 301 northwesterly to a shallow water junction platform with production handling facilities located at Ship Shoal Block 207 and (3) approximately 47 miles of 24-inch pipeline extending from Green Canyon Block 65 to Ship Shoal Block 207. Affiliates of Marathon and Shell have dedicated for gathering on the Manta Ray Offshore System significant deepwater acreage positions in the area. Marathon operates the Manta Ray Offshore System. Manta Ray is a subsidiary of Neptune, in which we own a 25.7% interest.

VIOSCA KNOLL SYSTEM. The Viosca Knoll System is an unregulated gathering system designed to serve the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico, southeast of New Orleans, offshore Louisiana. It consists of 125 miles of predominantly 20-inch diameter natural gas pipelines and a 7,000 horsepower compressor. The system provides its customers access to the facilities of a number of major interstate pipelines, including El Paso Energy, Columbia Gulf Transmission Company, Sonat, Transco and Destin Pipeline Company.

The base system was constructed in 1994 and is comprised of (1) an approximately 94 mile, 20-inch diameter pipeline from a platform in Main Pass Block 252 owned by Shell to a pipeline owned by a wholly owned El Paso Energy subsidiary at South Pass Block 55 and (2) a six mile, 16-inch diameter pipeline from an interconnection with the 20-inch diameter pipeline at our Viosca Knoll Block 817 platform to a pipeline owned by Southern Natural Gas Company at Main Pass Block 289. A 7,000 horsepower compressor was installed in 1996 on the Viosca Knoll Block 817 platform to allow the Viosca Knoll System to effect deliveries at the operating pressures on downstream interstate pipelines with which it is interconnected. The additional capacity created by such compression allowed Viosca Knoll to transport new natural gas volumes during 1997 from the Shell operated Southeast Tahoe and Ram-Powell fields as well as other new deepwater projects in the area. Recently, Viosca Knoll added approximately 25 miles of parallel 20-inch pipelines to the system east of the Viosca Knoll Block 817 platform to improve deliverability from certain Main Pass producing areas and redeliveries into the Transco pipeline at Main Pass Block 261 and the Destin pipeline at Main Pass Block 260. We operate the Viosca Knoll System.

Prior to the closing of the offering of our senior subordinated notes, Viosca Knoll was owned 50.0% by us and 50.0% by El Paso Energy (through a wholly owned subsidiary). In June 1999, we acquired all of El Paso Energy's interest in Viosca Knoll, other than a 1.0% interest, for $79.7 million, comprised of 25.0% in cash ($19.9 million) and 75.0% in common units (2,661,870 common units based on a price of $22.4625 per unit). At the closing of that transaction, (1) El Paso Energy contributed its interest in Viosca Knoll to us and approximately $33.4 million in cash to Viosca Knoll, which equaled 50.0% of the principal amount then outstanding under Viosca Knoll's credit facility, (2) we delivered to El Paso Energy the cash and common units discussed above and (3) as required by our partnership agreement, the general partner contributed approximately $604,000 to us in order to maintain its 1.0% capital account balance. Upon consummation of the acquisition, our partnership agreement was amended to ensure that, even though El Paso Energy beneficially owns an effective interest in us of 34.5%, the other unitholders will still have the votes necessary to remove the general partner and to call a meeting for such a purpose.

As a result of the acquisition, we own 99.0% of Viosca Knoll and have the option to acquire the remaining 1.0% interest during the six-month period commencing on the day after the first anniversary of the closing date. The option exercise price, payable in cash, is equal to the sum of $1.6 million plus the amount of additional distributions which would have been paid, accrued or been in arrears had we acquired the remaining 1.0% of Viosca Knoll at the initial closing by issuing additional common units in lieu of a cash payment of $1.7 million.

Although certain federal and state securities laws would otherwise limit El Paso Energy's ability to dispose of any common units held by it, El Paso Energy would have the right on three occasions to require us to file a registration statement covering such common units for a three-year period and to participate in offerings made pursuant to certain other registration statements filed by us during a ten-year period. Such registrations would be at our expense and, generally, would allow El Paso Energy to dispose of all or any of its common units. There can be no assurance (1) regarding how long El Paso Energy may hold any of its common units or (2) that El Paso Energy's disposition of a significant number of common units in a short period of time would not depress the market price of the common units.

Our unitholders of record as of January 28, 1999 ratified and approved the transactions in a meeting held March 5, 1999 based upon the ratification, approval and recommendation of the Board of Directors of the general partner and a Special Committee of independent directors of the general partner and based a fairness opinion of an independent financial advisor.

The acquisition of Viosca Knoll's interest closed on June 1, 1999.

STINGRAY SYSTEM. The Stingray System, owned 50.0% by us and 50.0% by NGPL, is a regulated natural gas transmission system consisting of (1) approximately 361 miles of 6- to 36-inch diameter pipeline that transports natural gas from the HIOS, West Cameron, East Cameron and Vermilion lease areas in the Gulf of Mexico to onshore transmission systems at Holly Beach, Cameron Parish, Louisiana, (2) approximately 12 miles of 16-inch diameter pipeline and approximately 31 miles of 20-inch diameter pipeline, connecting the Garden Banks Block 191 lease operated by Chevron U.S.A. Production Company and our 50.0%-owned Garden Banks Block 72 platform, respectively, to the system, and (3) approximately 13 miles of 16-inch diameter pipeline connecting our platform at East Cameron Block 373 to the Stingray System at East Cameron Block 338. NGPL will continue to operate the Stingray System until we take over those operations, probably by October 1, 1999.

HIOS SYSTEM. The HIOS System, indirectly owned 60.0% by us and 40.0% by ANR, is a regulated natural gas transmission system consisting of approximately 204 miles of pipeline comprised of three supply laterals, the West, Central and East Laterals, that connect to a 42-inch diameter mainline. The HIOS System transports natural gas received from fields located in the Galveston, Garden Banks, HIOS, West Cameron and East Breaks areas of the Gulf of Mexico to a junction platform owned by HIOS located in West Cameron Block 167. There, it interconnects with the UTOS system and a pipeline owned by ANR for further transportation to points onshore. ANR operates the HIOS System. HIOS is a subsidiary of Western Gulf, in which we own a 60.0% interest.

Prior to June 30, 1999, NGPL owned 20.0% of Western Gulf (and, thus, 20.0% of HIOS). On June 30, 1999 we acquired NGPL's 20.0% interest in Western Gulf, together with its 33.3% interest in UTOS and certain offshore pipeline laterals, for total consideration of approximately $51.0 million.

UTOS SYSTEM. The UTOS System, owned 66.7% by us and 33.3% by ANR, is a regulated natural gas transmission system consisting of approximately 30 miles of 42-inch diameter pipeline extending from a point of interconnection with the HIOS System at West Cameron Block 167 to the Johnson Bayou production handling facility. The UTOS System transports natural gas from the terminus of the HIOS System at West Cameron Block 167 to the Johnson Bayou facility, where it interconnects with several pipelines. The UTOS System is essentially an extension of the HIOS System, as almost all the natural gas transported through UTOS comes from the HIOS System. UTOS also owns the Johnson Bayou facility, which provides primarily natural gas and liquids separation and natural gas dehydration for natural gas transported on the HIOS and UTOS systems. ANR operates the UTOS System.

Prior to June 30, 1999, NGPL owned 33.3% of UTOS. On June 30, 1999 we acquired NGPL's 33.3% interest in UTOS, together with its 20.0% interest in Western Gulf and certain offshore pipeline laterals, for total consideration of approximately $51.0 million.

NAUTILUS SYSTEM. The Nautilus System, indirectly owned 25.7% by us, 50.0% by Tejas and 24.3% by Marathon, is a regulated natural gas transmission system consisting of 101 miles of 30-inch pipeline running downstream from Ship Shoal Block 207 and connecting to a natural gas production handling plant onshore Louisiana operated by Exxon and some other facilities downstream of that plant and effects deliveries to multiple interstate pipelines. Affiliates of Marathon and Tejas have dedicated to the Nautilus System certain deepwater acreage positions in the area. Marathon operates and maintains the Nautilus System and Tejas performs financial, accounting and administrative services for Nautilus. Nautilus is a subsidiary of Neptune, in which we own a 25.7% interest.

POSEIDON SYSTEM. The Poseidon System, owned 36.0% by us, 36.0% by Equilon Pipeline Company and 28.0% by a subsidiary of Marathon, is an unregulated major new sour crude oil pipeline system that was built in response to an increased demand for additional sour crude oil pipeline capacity in the central Gulf. The Poseidon System consists of (1) approximately 117 miles of 16- to 20-inch diameter pipeline extending in an easterly direction from our 50.0%-owned platform located at Garden Banks Block 72 to our platform located at Ship Shoal Block 332, (2) approximately 122 miles of 24-inch diameter pipeline extending in a northerly direction from the Ship Shoal Block 332 platform to Houma, Louisiana and (3) approximately 58 miles of 16-inch diameter pipeline extending northwesterly from Ewing Bank Block 873 to the Texaco-operated Eugene Island Pipeline System at Ship Shoal Block 141. In July 1998, Poseidon completed a 17-mile extension of 16-inch pipeline from Garden Banks Block 260 to South Marsh Island Block 205. Texaco pipelines and related facilities accept oil from Poseidon at Larose and Houma, Louisiana and redeliver it to St. James, Louisiana, a significant market hub for batching, handling and transportation of oil. Currently, Texaco operates the Poseidon system and has contracted with Equilon, LLC, a newly-formed joint venture between Texaco and Shell, to operate and perform the administrative functions related to Poseidon and the Poseidon System. In April 1999, Texaco assigned its membership interest in Poseidon to Equilon.

OIL AND NATURAL GAS SUPPLY

A substantial portion of the reserves handled by our pipelines is committed pursuant to long-term contracts, for the productive life of the relevant field. Nonetheless, these reserves and other reserves that may become available to our pipelines are depleting assets and, as such, will be produced over a finite period. Each of our pipelines 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.

As somewhat reflected by throughput for 1998, Manta Ray Offshore, Viosca Knoll and Tarpon obtained commitments from new fields and some additional commitments from existing fields. However, Green Canyon, Stingray, HIOS and UTOS were not able to offset reductions in throughput associated with normal production declines for committed reserves with throughput associated with commitments of additional reserves. Nevertheless, we believe that there will be sufficient reserves available to the natural gas pipelines for transportation to maintain throughput at or near current levels for at least several years.

In addition to the production commitments from Texaco and Marathon, Poseidon has been successful in obtaining long-term commitments of production from several properties containing significant reserves. Poseidon has contracted with affiliates of Exxon, Phillips Petroleum, BP Amoco, Anadarko, Newfield Exploration, Mobil, Amerada Hess, Oryx, Sun, PennzEnergy, Enterprise Oil, British Borneo, Occidental and us. We anticipate that Poseidon will add more commitments as new subsalt and Deepwater fields are developed in the area which the Poseidon System serves, but we cannot assure you any such commitment would be made or when the production from such commitment would be initiated. However, we do believe that there should be significant increases in reserves committed to the Poseidon System for at least the next several years.

Tatham Offshore's Ewing Bank Block 914 #2 well was the only production dedicated to the Ewing Bank system. In May 1997, the well was shut in due to a mechanical problem. After approximately one year of evaluating certain remedies to place the well on production, we decided, along with Tatham Offshore, to abandon the well and the Ewing Bank system in May 1998.

OFFSHORE PLATFORMS AND RELATED FACILITIES

Our offshore platforms play a key role in the development of the oil and natural gas offshore pipeline network. Platforms are used to interconnect the offshore pipeline grid; to provide an efficient means to perform pipeline maintenance; to locate compression, separation, production handling and other facilities; and during the initial development phase of an oil and natural gas property, to conduct drilling operations. In addition to numerous platforms owned by our joint ventures, we own six strategically-located platforms in the Gulf of Mexico, including three multi-purpose hub-platforms, Viosca Knoll 817, Garden Banks 72 and East Cameron 373. These three platforms were specifically designed to be used as Flextrend and Deepwater landing sites and production handling and pipeline maintenance facilities. Further, we recently began construction of a Moses Tension Leg Platform in connection with the development of our Ewing Bank 958 Unit.

	VIOSCA KNOLL 817	GARDEN BANKS 72	EAST CAMERON 373	SHIP SHOAL 332	SOUTH TIMBALIER 292	SHIP SHOAL 331
Ownership interest........	100%	50%	100%	100%	100%	100%
In-service date...........	1995	1995	1998	1985	1984	1994
Water depth (in feet).....	671	518	441	438	283	376
Acquired (A) or constructed (C).........	C	C	C	A	A	A
Product handling capacity:						
Natural gas (MMcf per day).................	140	80	110	150(1)	150	--(1)
Oil and condensate (bbls per day).............	5,000	55,000	5,000	12,000(1)	2,500	--(1)

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(1) Our Ship Shoal Block 331 platform is currently used as a satellite landing area and all products transported over the platform are processed on our Ship Shoal Block 332 platform.

VIOSCA KNOLL BLOCK 817. We constructed a multi-purpose platform located in Viosca Knoll Block 817 in 1995. We used this platform as a base for conducting drilling operations for oil and natural gas reserves located on the Viosca Knoll Block 817 lease. In addition, the platform serves as a base for landing other Deepwater production in the area, thereby generating platform access and production handling fees for us. A 7,000 horsepower compressor was installed in 1996 on the Viosca Knoll Block 817 platform to allow the Viosca Knoll System to effect deliveries at the operating pressures on downstream interstate pipelines with which it is interconnected. The additional capacity created by such compression allowed Viosca Knoll to transport new natural gas volumes during 1997 from the Shell-operated Southeast Tahoe and Ram-Powell fields as well as other new Deepwater projects in the area. Viosca Knoll leases space on this platform from us for the location of the new compression equipment for the Viosca Knoll System. We own 100% of the Viosca Knoll 817 platform.

GARDEN BANKS BLOCK 72. We own a 50.0% interest in a multi-purpose platform located in Garden Banks Block 72. This platform is located at the south end of the Stingray System and serves as the westernmost terminus of the Poseidon System. We also use this platform in our drilling and production operations. It now serves as the landing site for production from our Garden Banks Block 117 lease located in an adjacent lease block.

EAST CAMERON BLOCK 373. In 1998, we placed in service a new multi-purpose platform located in East Cameron Block 373 at a construction cost of $30.2 million. This four pile production platform with production handling facilities is strategically located to exploit deeper water reserves in the East Cameron and Garden Banks areas of the Gulf of Mexico and is the terminus for an extension of the Stingray System. Kerr McGee Corporation has rights to utilize a portion of the platform and has committed its production from multiple blocks in the East Cameron and Garden Banks areas to be processed on this platform and transported through the Stingray System. We own 100% of the East Cameron Block 373 platform.

SHIP SHOAL BLOCK 332. We own a 100% interest in a platform located in Ship Shoal Block 332 which serves as a junction platform for natural gas pipelines in the Manta Ray Offshore System as well as an eastern junction for the Poseidon System.

SOUTH TIMBALIER BLOCK 292. The South Timbalier Block 292 platform is a 100%-owned facility located at the easternmost terminus of the Manta Ray Offshore System and serves as a landing site for natural gas production in that area.

SHIP SHOAL BLOCK 331. In August 1998, in connection with El Paso Energy's acquisition of our general partner, we acquired the Ship Shoal Block 331 platform, a production facility located 75 miles off the coast of Louisiana in approximately 370 feet of water. Pogo Producing Company has certain rights to utilize the platform pursuant to a production handling and use of space agreement. We own 100% of the Ship Shoal Block 331 platform.

OTHER FACILITIES. Through our 50.0% ownership interest in West Cameron Dehy, we own an interest in certain dehydration facilities located at the northern terminus of the Stingray System, onshore Louisiana.

MAINTENANCE

Each of our pipelines requires regular and thorough maintenance. The interior of pipelines is maintained through the regular "pigging" of the lines. Pigging involves propelling a large spherical object through the line which collects, or pushes, any condensate and other liquids on the walls or at the bottom of the pipeline through the line and out the far end. More sophisticated pigging devices include those with scrapers, brushes and x-ray devices; however, such pigging devices are usually deployed only on an as needed basis. 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, sacrificial anodes are fastened to the pipeline at prescribed intervals, providing protection from sea water. Our platforms are painted to the waterline every three to five years to prevent atmospheric corrosion. Sacrificial anodes are also fastened to the platform legs below the waterline to prevent corrosion. A sacrificial anode is a zinc aluminum alloy fixture that is attached to the exterior of a steel object to attract the corrosive reaction that occurs between steel and saltwater to the fixture itself, thus protecting the steel object from corrosion. Remotely operated vehicles or divers inspect our platforms below the waterline, usually every five years.

The Stingray, HIOS, Viosca Knoll, Manta Ray Offshore and Poseidon systems include platforms that are manned on a continuous basis. The personnel onboard those platforms are responsible for site maintenance, operations of the facilities on the platform, measurement of the natural gas stream at the source of production and corrosion control (pig launching and inhibitor injection).

COMPETITION

Each of our natural gas pipelines is located in or near natural gas production areas that are served by other pipelines. As a result, each of our natural gas pipeline systems faces competition from both regulated and unregulated systems. Some of these competitors are not subject to the same level of rate and service regulation as, and may have a lower cost structure than, our natural gas pipelines. Other competing pipelines, such as long-haul transporters, have rate design alternatives unavailable to our natural gas pipelines. Consequently, those competing pipelines may be able to provide service on more flexible terms and at rates significantly below the rates offered by our natural gas pipelines. The principal competitors of our regulated pipeline systems are Shell, Texaco, ANR, Transco, Trunkline Gas Co., Texas Eastern, Columbia Gas Transmission and their affiliates.

The Poseidon System was built as a result of our belief that additional sour crude oil capacity was required to transport new subsalt and Deepwater oil production to shore. Poseidon's principal competitors for additional crude oil production are Equilon (a 36.0% owner of Poseidon), which owns the Texaco-operated Eugene Island Pipeline and the Shell-operated Amberjack systems that compete with Poseidon and oil pipelines built, owned and operated by producers to handle their own production and, as capacity is available, production for others. Our pipelines compete for new production with these and other competitors 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 the pipelines to access future reserves will be subject to the ability of the pipelines or the producers to fund the anticipated significant capital expenditures required to connect the new production.

CUSTOMERS AND CONTRACTS

GENERAL. The rates we charge for our services are dependent on (1) whether the relevant pipeline, platform, production handling, dehydration or other facility is regulated or unregulated -- established maximum rate or fully negotiated rate, (2) the quality of the service required by the customer -- interruptible or firm, and (3) the amount and term of the reserve commitment by the customer. A significant portion of our arrangements involve life-of-reserve commitments with both firm and interruptible components. Generally, we receive a price per unit (Mcf of natural gas or barrel of oil or water) handled. And depending on transaction specific factors, for firm arrangements, we often also receive a monthly fixed fee which is paid by the customer regardless of the level of throughput, except under individually specified circumstances.

The Poseidon System receives crude oil from committed properties under buy/sell agreements, often surviving for the life of the property. The same factors described above affect the contract amounts and other terms.

PRINCIPAL CUSTOMERS. See our consolidated financial statements and notes thereto located elsewhere in this prospectus for certain information regarding our principal transportation customers.

NATURAL GAS AND OIL PROPERTIES ASSOCIATED WITH INFRASTRUCTURE OPPORTUNITIES

In areas we serve or desire to serve, we occasionally pursue opportunistic investments in pipelines, platforms, production handling facilities and other infrastructure assets, as well as selective investment in oil and natural gas properties. By providing infrastructure to previously unserved geographic regions, we try to accelerate the development of oil and natural gas properties in that area. The ability to access common facilities allows producers to share the high fixed costs associated with infrastructure and, in certain circumstances, results in the economic development of otherwise marginal reserves and in an increase in the total reserves produced from that region. Further, we may invest in oil and natural gas properties when it augments the utilization of our existing assets or leads to a strategic infrastructure opportunity. We use our pipelines and other facilities to process, gather and transport the oil and gas produced from oil and natural gas properties in which we have invested. We sell the majority of that production to Offshore Gas Marketing, Inc., our affiliate and an indirectly owned subsidiary of El Paso Energy.

Currently, we own interests in three material producing and one non-producing oil and natural gas properties located primarily in waters offshore Louisiana. We acquired our Viosca Knoll 817, Garden Banks 72 and Garden Banks 117 properties from a financially distressed producer in 1995 for approximately $30.0 million. We developed that property in connection with the construction of our Viosca Knoll System, which at the time was a 50/50 joint venture with Tenneco Inc. As operator, we concluded development and placed eight wells on production on our Viosca Knoll 817 property. Currently, these wells have gross aggregate average production of approximately 35.0 MMcf of natural gas per day. In addition to developing an oil and natural gas property and constructing one of the few natural gas pipelines in an emerging production region in the Flextrend area offshore Louisiana and Mississippi, we successfully constructed, marketed and operated our first multi-purpose hub-platform, which has been used as a landing and processing site for Flextrend and Deepwater properties in the area, as well as a pipeline maintenance facility and, during the development phase, a drilling facility. Recently, due to demand, we completed two expansion projects that more than doubled the throughput capacity of our Viosca Knoll System to 1.0 Bcf of natural gas per day.

We completed the joint development of our Garden Banks 72 and 117 properties in 1997. That development project included a multi-purpose hub-platform located on Garden Banks 72, which has been used:

- to drill five wells on Garden Banks 72;
- to tie-back the Garden Banks 117 #1 and #2 wells;
- to locate separating and processing facilities; and
- as a junction landing and maintenance site for our Poseidon and Stingray systems.

The Garden Banks 72 and 117 properties contain seven wells, which are currently producing a gross aggregate average of approximately 6.2 MMcf of natural gas per day and 2,400 barrels of oil per day.

We purchased the Ewing Bank 958 Unit in October 1998 from a wholly owned, indirect subsidiary of El Paso Energy. Our current plan of development contemplates the construction of a gathering system and a Moses Tension Leg Platform. This platform, which may be used in up to 6,000 feet of water, will have production handling facilities with a throughput design capacity of 55.0 MMcf of natural gas per day and 25,000 barrels of oil per day. Accordingly, we recently began construction of the Moses Tension Leg Platform, which will be designed to support a deck and topside facilities weighing up to 6,000 short tons and process 25,000 barrels of oil per day and 55.0 MMcf of natural gas per day. In addition to the initial discovery well drilled in 1994 and the two delineation wells drilled in 1994 and 1998, the Ewing Bank 958 Unit development program could require drilling up to five additional wells, depending on the level of actual production and other factors. To date there has been no production from the Ewing Bank 958 Unit.

The following is a description of our currently held properties.

VIOSCA KNOLL BLOCK 817. Viosca Knoll Block 817 is a producing property that is comprised of 5,760 gross and net acres located 40 miles off the coast of Louisiana in approximately 670 feet of water.

Initially, we acquired a 75.0% working interest in Viosca Knoll Block 817 from the sea-floor through the stratigraphic equivalent of the base of the Tex X-6 Sand, subject to certain reversionary rights. In connection with El Paso Energy's acquisition of our general partner, those reversionary rights were relinquished and we acquired the remaining 25.0% working interest in Viosca Knoll Block 817. This working interest is subject to a production payment that entitles the holders in the aggregate to 25.0% 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 $16.0 million. At December 31, 1998, the unpaid portion of the production payment obligation totaled $11.1 million.

As operator, we concluded a drilling program and placed eight wells on production on Viosca Knoll Block 817. We do not anticipate drilling any more wells or having any other major expenditures with respect to this property except for the possible recompletion of certain existing wells. From inception of production in December 1995 through December 31, 1998, the Viosca Knoll property has produced 42,661 MMcf of natural gas and 67.6 Mbbls of oil, net to our interest. During June 1999, Viosca Knoll Block 817 produced an aggregate of approximately 35.0 MMcf of natural gas per day. Natural gas production from Viosca Knoll Block 817 is dedicated to us for gathering through the Viosca Knoll System and oil production is transported through a Shell-operated system. Our recent expansion of the Viosca Knoll System eliminated downstream pipeline capacity constraints on that system and is expected to allow us to produce Viosca Knoll Block 817 at optimal rates in the future.

GARDEN BANKS BLOCK 72. Garden Banks Block 72 covers 5,760 gross (2,880 net) acres and is located 120 miles off the coast of Louisiana in approximately 550 feet of water. In 1995, we acquired a 50.0% working interest (approximately 40.2% net revenue interest) in Garden Banks Block 72, subject to certain reversionary interests which were relinquished in connection with El Paso Energy's acquisition of our general partner. A subsidiary of Occidental Petroleum Company owns the remaining 50.0% working interest in Garden Banks Block 72.

Since May 1996, we have placed five wells on production at Garden Banks Block 72. We do not anticipate drilling any more wells or having any other major expenditures with respect to this property except for the possible recompletion of certain existing wells. Production at Garden Banks Block 72 totaled 2,979 MMcf of natural gas and 902.1 Mbbls of oil, net to our interest, from the inception of production in May 1996 through December 31, 1998. During June 1999, the five wells produced a total of approximately 1.2 Mbbls of oil and 3.6 MMcf of natural gas per day. Natural gas production from Garden Banks Block 72 is being transported through the Stingray System and the oil production is delivered to the Poseidon System.

GARDEN BANKS BLOCK 117. Garden Banks Block 117 covers 5,760 gross (2,880 net) acres adjacent to Garden Banks Block 72 and is located in approximately 1,000 feet of water. In 1995, we acquired a 50.0% working interest (approximately 37.5% net revenue interest) in Garden Banks Block 117, subject to certain reversionary interests which were relinquished in connection with El Paso Energy's acquisition of our general partner. Midcon Exploration owns the remaining 50.0% working interest in Garden Banks Block 117.

In July 1996 and May 1997, we completed and initiated production from the Garden Banks Block 117 #1 and #2 wells, respectively. During June 1999, these wells produced a total of approximately 1.2 Mbbls of oil and 2.6 MMcf of natural gas per day. Since inception of production through December 31, 1998, Garden Banks Block 117 produced 1,327 MMcf of natural gas and 761.8 Mbbls of oil, net to our interest. We do not anticipate drilling any more wells on this property except for a recompletion of the Garden Banks 117 #2 well. Natural gas production from Garden Banks Block 117 is transported on the Stingray system and oil production is delivered to the Poseidon System.

WEST DELTA BLOCK 35. In connection with El Paso Energy's acquisition of our general partner, we acquired a 38.0% non-operating working interest in West Delta Block 35, a producing field located 10 miles off the coast of Louisiana in approximately 60 feet of water covering 4,985 gross (1,894 net) acres. The West Delta Block 35 field commenced production in July 1993. Since August 14, 1998 through

December 31, 1998, West Delta Block 35 produced 272 MMcf of natural gas and 2.2 Mbbls of oil, net to our interest.

EWING BANK 958 UNIT. We purchased the Ewing Bank 958 Unit in October 1998 from a wholly owned, indirect subsidiary of El Paso Energy. Our current plan of development contemplates the construction of a gathering system and a Moses Tension Leg Platform. This platform, which may be used in up to 6,000 feet of water, will have production handling facilities with a throughput design capacity of 55.0 MMcf of natural gas per day and 25,000 barrels of oil per day. Accordingly, we recently began construction of the Moses Tension Leg Platform, which will be designed to support a deck and topside facilities weighing up to 6,000 short tons and process 25,000 barrels of oil per day and 55.0 MMcf of natural gas per day. In addition to the initial discovery well drilled in 1994 and the two delineation wells drilled in 1994 and 1998, the Ewing Bank 958 Unit development program could require drilling up to five additional wells, depending on the level of actual production and other factors. To date there has been no production from the Ewing Bank 958 Unit.

COMPETITION

The oil and natural gas industry is intensely competitive. In all segments of our business, we compete with a substantial number of other companies, including some with larger technical staffs and greater financial and operational resources. Many such competitors are more vertically integrated than we are -- that is, they not only acquire, explore for, develop, produce, gather and transport oil and natural gas reserves, but also carry on refining operations, generate electricity and market refined products. As a result, many of our competitors may be better positioned to acquire and exploit prospects, hire personnel, market production and withstand the effects of general and/or industry-specific economic changes. We also face potential competition from companies not previously active in oil and natural gas who may choose to acquire reserves to establish a firm supply or simply as an investment. In addition, the oil and natural gas industry competes with other industries supplying energy and fuel to industrial, commercial and individual consumers.

PRODUCTION, UNIT PRICES AND COSTS

The following table sets forth certain information regarding the production volumes of, average unit prices received for and average production costs for our sale of oil and natural gas for the periods indicated:

	OIL (BARRELS) YEAR ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	NATURAL GAS (MMCF) YEAR ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,
	1996	1997	1998	1999	1996	1997	1998	1999
Net production(1)	393,000	801,000	540,000	193,000	15,730	19,792	11,324	6,877
Average sales price(1)	$ 21.76	$ 20.61	$ 15.69	$ 12.69	$ 2.37	$ 2.08	$ 2.01	$ 1.83
Average production costs(2)	$ 1.59	$ 1.98	$ 3.04	$ 2.35	$ 0.27	$ 0.33	$ 0.51	$ 0.39

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(1) The information regarding production and unit prices excludes overriding royalty interests.
(2) The components of production costs may vary substantially among wells depending on the methods of recovery employed and other factors, but generally include third party transportation expenses, maintenance and repair, labor and utilities costs.

The relationship between average sales prices and average production costs depicted by the table above is not necessarily indicative of future expected results of our operations.

OIL AND NATURAL GAS RESERVES

The following estimates of our total proved developed and proved undeveloped reserves of oil and natural gas as of December 31, 1998 have been made by Netherland, Sewell & Associates, Inc., an independent petroleum engineering consulting firm.

	OIL (BARRELS)	NATURAL GAS (MCF)	
	PROVED DEVELOPED	PROVED DEVELOPED	PROVED UNDEVELOPED
Viosca Knoll Block 817	80,592	21,700,344	2,452,000
Garden Banks Block 72	495,437	2,306,934	--
Garden Banks Block 117	991,888	1,645,839	--
West Delta Block 35	9,599	779,179	--
Total	1,577,516	26,432,296	2,452,000

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 sites, may vary substantially. The meaningfulness of such estimates is highly dependent upon the assumptions upon which they are based.

Furthermore, production from Garden Banks Block 117, Garden Banks Block 72 and Viosca Knoll Block 817 was initiated in July 1996, May 1996 and December 1995, respectively, and, accordingly, estimates of future production are based on this limited history. 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.

The following table sets forth, as of December 31, 1998, the estimated future net cash flows and the present value of estimated future net cash flows, discounted at 10.0% per annum, from the production and sale of the proved developed and undeveloped reserves attributable to our interest in oil and natural gas properties as of such date, as determined by Netherland, Sewell in accordance with the requirements of applicable accounting standards, before income taxes.

	DECEMBER 31, 1998		
	PROVED DEVELOPED	PROVED UNDEVELOPED	TOTAL PROVED
	(IN THOUSANDS)		
Undiscounted estimated future net cash flows from proved reserves before income taxes(1)	$28,457	$864	$29,321
Present value of estimated future net cash flows from proved reserves before income taxes, discounted at 10.0%(2)	$26,131	$541	$26,672

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(1) The average oil and natural gas prices, as adjusted by lease for gravity and Btu content, regional posted price differences and oil and natural gas price hedges in place and weighted by production over the life of the proved reserves, used in the calculation of estimated future net cash flows at December 31, 1998 are $9.80 per barrel of oil and $1.53 per Mcf of natural gas.

(2) We estimate that, if all other factors (including the estimated quantities of economically recoverable reserves) were held constant, a $1.00 per barrel change in oil prices from that used in the Netherland, Sewell reserve report would change the December 31, 1998 present value of future net cash flows from proved reserves by approximately $1.3 million or a $0.10 per Mcf change in gas prices from that used in the Netherland, Sewell reserve report would change such present value by approximately $3.1 million.

In accordance with applicable requirements of the SEC, the estimated discounted future net revenue from estimated proved reserves are based on prices and costs at fiscal year end unless future prices or costs are contractually determined at such date. Actual future prices and costs may be materially higher or lower. Actual future net revenue also will be affected by factors such as actual production, supply and demand for oil and natural gas, curtailments or increases in consumption by natural gas purchasers, changes in governmental regulations or taxation and the impact of inflation on costs.

In accordance with the methodology approved by the SEC, specific assumptions were applied in the computation of the reserve evaluation estimates. Under this methodology, future net cash flows are determined by reducing estimated future gross cash flows to us for oil and natural gas sales by the estimated costs to develop and produce the underlying reserves, including future capital expenditures, operating costs, transportation costs, royalty and overriding royalty burdens, production payments and net profits interest expense on certain of our properties.

Future net cash flows were discounted at 10.0% per annum to arrive at discounted future net cash flows. The 10.0% discount factor used to calculate present value is required by the SEC, but such rate is not necessarily the most appropriate discount rate. Present value of future net cash flows, irrespective of the discount rate used, is materially affected by assumptions as to timing of future oil and natural gas prices and production, which may prove to be inaccurate. In addition, the calculations of estimated net revenue do not take into account the effect of certain cash outlays, including, among other things, general and administrative costs, interest expense and partner distributions. The present value of future net cash flows shown above should not be construed as the current market value as of December 31, 1998, or any prior date, of the estimated oil and natural gas reserves attributable to our properties.

ACREAGE

The following table sets forth our developed and undeveloped oil and natural gas acreage as of December 31, 1998. Undeveloped acreage is considered to be 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 we own directly a working interest. The number of net acres is our fractional ownership of working interests in the gross acres.

	GROSS	NET
Developed acreage	6,792	5,416
Undeveloped acreage	59,577	48,862
Total acreage	66,369	54,278

OIL AND NATURAL GAS DRILLING ACTIVITY

The following table sets forth the gross and net number of productive, dry and total exploratory wells and development wells that we have drilled in each of the respective years:

	YEAR ENDED DECEMBER 31,					
	1998		1997		1996	
	GROSS	NET	GROSS	NET	GROSS	NET
Exploratory						
Natural gas	--	--	--	--	--	--
Oil	--	--	--	--	1.00	0.50
Dry	--	--	--	--	--	--
Total	--	--	--	--	1.00	0.50
Development						
Natural gas	--	--	--	--	7.00	5.00
Oil	1.00	1.00	--	--	5.00	2.75
Dry	--	--	--	--	3.00	1.75
Total	1.00	1.00	--	--	15.00	9.50

The following table sets forth our ownership in producing wells at December 31, 1998:

	GROSS	NET
Natural gas	10.00	8.26
Oil	6.00	3.00
Total	16.00	11.26

MAJOR ENCUMBRANCES

Substantially all of the operating assets in which we own an interest are owned by our subsidiaries or joint ventures. Substantially all of our assets (primarily our interests in our subsidiaries) and our subsidiaries' assets are pledged as collateral to secure obligations under our credit facility. In addition, certain of our joint ventures currently have, and others are expected to have, credit facilities pursuant to which substantially all of such joint ventures' assets are or would be pledged.

REGULATION

The oil and natural gas industry is extensively regulated by federal and state authorities in the U.S. Numerous departments and agencies, both federal and state, have issued rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for the failure to comply. Legislation affecting the oil and natural gas industry is under constant review and statutes are constantly being adopted, expanded or amended. The regulatory burden on the oil and natural gas industry increases its cost of doing business.

GENERAL. The design, construction, operation and maintenance of our natural gas pipelines and of certain of their natural gas transmission facilities are subject to regulation by the Department of

Transportation under the Natural Gas Pipeline Safety Act of 1968 as amended (the "NGPSA"). Operations in offshore federal waters are regulated by the Department of Interior and the FERC. Under the Outer Continental Shelf Lands Act (the "OCSLA") as implemented by the FERC, pipelines that transport natural gas across the OCS must offer nondiscriminatory transportation of natural gas. Substantially all of the pipeline network owned by our pipelines is located in federal waters in the Gulf of Mexico, and the related rights-of-way were granted by the federal government, the agencies of which oversee such pipeline operations. Federal rights-of-way require compliance with detailed federal regulations and orders which regulate such operations.

Poseidon is subject to regulation under the Hazardous Liquid Pipeline Safety Act ("HLPSA"). In addition, under the OCSLA, as implemented by the FERC, pipelines that transport crude oil across the OCS must offer "equal access" to other potential shippers of crude. The Poseidon System is located in federal waters in the Gulf of Mexico, and its right-of-way was granted by the federal government. Therefore, the FERC may assert that it has jurisdiction to compel Poseidon to grant access under the OCSLA to other shippers of crude oil upon the satisfaction of certain conditions and to apportion the capacity of the line among owner and non-owner shippers.

RATES. Each of our regulated pipelines (the Nautilus, Stingray, HIOS and UTOS systems) is classified as a "natural gas company" by the NGA. Consequently, the FERC has jurisdiction over these regulated pipelines 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. In addition, these regulated pipelines hold certificates of public convenience and necessity issued by the FERC authorizing their facilities, activities and services.

Under the terms of the regulated pipelines' tariffs on file at the FERC, the regulated pipelines may not charge or collect more than the maximum rates on file with the FERC. FERC regulations permit natural gas pipelines to charge maximum rates that generally allow pipelines the opportunity to (1) recover operating expenses, (2) recover the pipeline's undepreciated investment in property, plant and equipment ("rate base") and (3) receive an overall allowed rate of return on the pipeline's rate base. We believe that even after the rate base of any regulated pipeline is substantially depleted, the FERC will allow such regulated pipeline to recover a reasonable return, whether through a management fee or otherwise.

Each of the Nautilus, Stingray, HIOS and UTOS systems is currently operating under agreements with their respective customers that provide for rates that have been approved by the FERC.

On March 13, 1997, the FERC issued an order declaring Tarpon's facilities exempt from NGA regulation under the gathering exception, thereby terminating Tarpon's status as a "natural gas company" under the NGA. Tarpon has agreed, however, to continue service for shippers that have not executed replacement contracts on the terms and conditions, and at the rate reflected in, its last effective regulated tariff for two years from the date of the order. None of the Green Canyon, Ewing Bank, Manta Ray Offshore or Viosca Knoll systems is currently, nor do we expect East Breaks to be, considered a "natural gas company" under the NGA. Consequently, these companies are not subject to extensive FERC regulation under the NGA or the Natural Gas Policy Act of 1978, as amended (the "NGPA"), and are thus allowed to negotiate the rates and terms of service with their respective shippers, subject to the "equal access" requirements of the OCSLA.

The FERC has asserted its NGA rate jurisdiction over services performed through gathering facilities owned by a natural gas company (as defined in the NGA) when such services were performed "in connection with" transportation services provided by such natural gas company. Whether, and to what extent, the FERC should exercise any NGA rate jurisdiction it may be found to have over gathering facilities owned either by natural gas companies or affiliates thereof is subject to case-by-case review by the FERC. Based on current FERC policy and precedent, we do not anticipate that the FERC will assert or exercise any NGA rate jurisdiction over the Green Canyon, Ewing Bank, Manta Ray Offshore, Viosca Knoll or East Breaks systems, so long as the services provided through such lines are not performed "in connection with" transportation services performed through any of the regulated pipelines.

The FERC has generally disclaimed jurisdiction to set rates for oil pipelines in the OCS under the Interstate Commerce Act. As a result, Poseidon, as operator of the Poseidon system, has not filed tariffs with the FERC for the Poseidon system.

PRODUCTION AND DEVELOPMENT. Our production and development operations are subject to regulation at the federal and state levels. Such regulation includes requiring permits for the drilling of wells and maintaining bonds and insurance requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the 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 unitization or 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 MMS. Individuals and entities must qualify with the MMS prior to owning and operating any leasehold or right-of-way interest in federal waters. Such qualification with the MMS generally involves filing certain documents with the MMS and obtaining an area-wide performance bond and, in some cases, supplemental bonds representing security deemed necessary by the MMS in excess of the area-wide bond requirements for facility abandonment and site clearance costs.

OPERATIONAL HAZARDS AND INSURANCE

Pipelines, platforms and other offshore assets may experience damage as a result of an accident or other natural disaster, especially in the deeper water regions. In addition, our production and development operations are subject to the usual hazards incident to the drilling and production of natural gas and crude oil, such as blowouts, cratering, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pollution, releases of toxic gas and other environmental hazards and risks. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damages and suspension of operations. To mitigate the impact of repair costs associated with such an accident or disaster, we maintain insurance of various types that we consider to be adequate to cover our operations. In our opinion, this insurance provides reasonable coverage for all of our assets except for our 50.0% interest in the assets of Stingray, for which insurance providing reasonable coverage is carried at the Stingray level. The insurance package is subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines or the drilling and production of oil and natural gas. Consistent with insurance coverage generally available to the industry, our insurance policies do not provide coverage for losses or liabilities relating to pollution, except for sudden and accidental occurrences. We do, however, have certificates of financial responsibility of not less than $35.0 million per offshore facility and/or lease.

The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe that we are adequately insured for public liability and property damage to others with respect to its operations. However, we can give no assurance that we will be able to maintain adequate insurance in the future at rates we consider reasonable.

INDUSTRY CONDITIONS

Profitability and cash flow in the oil and natural gas industry largely depend on the market prices of oil and natural gas, which historically have been seasonal, cyclical, volatile and driven by general economic developments, governmental regulations and many other factors, including weather and political conditions. Commodity prices for hydrocarbons were very volatile in 1998 and continue to be in 1999, including some significant declines. These commodity prices also declined dramatically from 1981 until the mid-1980's and increased noticeably from the mid-1980's through the early 1990's.

Supply and demand conditions and regulatory factors have been the primary contributors to this oil and natural gas price volatility as well as a related restructuring of certain segments of the energy industry.

Increases in worldwide oil production capability and decreases in energy consumption have brought about substantial surpluses in oil supplies in recent years. This, in turn, has resulted in substantial domestic competition between oil and natural gas for end-use markets. Changes in government regulations relating to the production, transportation and marketing of natural gas have also resulted in significant changes in the historical marketing patterns of the natural gas industry. Generally, these changes have resulted in the abandonment by many pipelines of long-term contracts for the purchase of natural gas, the development by natural gas producers of their own marketing programs to take advantage of new regulations requiring pipelines to transport natural gas for regulated fees, and the emergence of various types of marketing companies and other aggregators of natural gas supplies.

As a result of the recent steep decline in energy commodity prices, internal and external sources of cash have become constrained, and accordingly, some industry participants have reduced offshore exploration and development budgets. The future direction of these commodity prices is uncertain, as are the long-term effects on the industry.

ENVIRONMENTAL

GENERAL. Our operations are subject to extensive federal, state and local statutory and regulatory requirements relating to environmental affairs, health and safety, waste management and chemical products. In recent years, these requirements have become increasingly stringent and in certain circumstances, they impose "strict liability" on a company, rendering it liable for environmental damage without regard to negligence or fault on the part of such company. To our knowledge, our operations are in substantial compliance, and are expected to continue to comply in all material respects, with applicable environmental laws, regulations and ordinances.

It is possible, however, that future developments, such as stricter environmental laws, regulations or enforcement policies could affect the handling, manufacture, use, emission or disposal of substances or wastes by us or our pipelines. In addition, some risk of environmental costs and liabilities is inherent in our operations and products as it is with other companies engaged in similar or related businesses, and there can be no assurance that we will not incur material costs and liabilities, including substantial fines and criminal sanctions for violation of environmental laws and regulations. Furthermore, we will likely be required to increase our expenditures during the next several years to comply with higher industry and regulatory safety standards. However, such expenditures cannot be accurately estimated at this time.

PIPELINES. In addition to the NGA, the NGPA and the OCSLA, several federal and state statutes and regulations may pertain specifically to the operations of our pipelines. The Hazardous Materials Transportation Act, 49 U.S.C. sec. 5101 et seq., as amended, regulates materials capable of posing an unreasonable risk to health, safety and property when transported in commerce. The NGPSA and the HLPSA authorize the development and enforcement of regulations governing pipeline transportation of natural gas and hazardous liquids. Although federal jurisdiction is exclusive over regulated pipelines, the statutes allow states to impose additional requirements for intrastate lines if compatible with federal programs. Both Texas and Louisiana have developed regulatory programs that parallel the federal program for the transportation of natural gas by pipelines.

SOLID WASTE. The operations of our pipelines may generate or transport both hazardous and nonhazardous solid wastes that are subject to the requirements of the federal Resource Conservation and Recovery Act ("RCRA"), as amended, 42 U.S.C. sec. 6901 et. seq., and its regulations, and comparable state statutes and regulations. Further, it is possible that some wastes that are currently classified as nonhazardous, via exemption or otherwise, perhaps including wastes currently generated during pipeline operations, may, in the future, be designated as "hazardous wastes," which would then be subject to more rigorous and costly treatment, storage, transportation and disposal requirements. Such changes in the regulations may result in additional expenditures or operating expenses by Leviathan. On August 8, 1998, the Environmental Protection Agency ("EPA") added four petroleum refining wastes to the list of RCRA hazardous wastes. While the full impact of the rule has yet to be determined, the rule may, as of February 1999, impose increased expenditures and operating expenses on us or our pipelines, which may take on increased obligations relating to the treatment, storage, transportation and disposal of certain petroleum refining wastes that previously were not regulated as hazardous waste.

HAZARDOUS SUBSTANCES. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), 42 U.S.C. sec. 9601 et. seq., and comparable state statutes, also known as "Superfund" laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that cause or contribute to the release of a "hazardous substance" into the environment. These persons include the current owner or operator of a site, the past owner or operator of a site, and companies that transport, dispose of, or arrange for the disposal of the hazardous substances found at the site. CERCLA also authorizes the EPA or state agency, and in some cases, third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Despite the "petroleum exclusion" of Section 101(14) that currently encompasses natural gas, we may nonetheless generate or transport "hazardous substances" within the meaning of CERCLA, or comparable state statutes, in the course of our ordinary operations. And, certain petroleum refining wastes that previously were not regulated as hazardous waste may now fall within the definition of CERCLA hazardous substances. Thus, we may be responsible under CERCLA or the state equivalents for all or part of the costs required to cleanup sites where a release of a hazardous substance has occurred.

AIR. Our operations may be subject to the Clean Air Act ("CAA"), 42 U.S.C. sec. 7401-7642, and comparable state statutes. The 1990 CAA amendments and accompanying regulations, state or federal, may impose certain pollution control requirements with respect to air emissions from operations, particularly in instances where a company constructs a new facility or modifies an existing facility. We may also be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. However, we do not believe our operations will be materially adversely affected by any such requirements.

WATER. The Federal Water Pollution Control Act ("FWPCA") or Clean Water Act, 33 U.S.C. sec. 1311 et. seq., imposes strict controls against the unauthorized discharge of produced waters and other oil and natural gas wastes into navigable waters. The FWPCA provides for civil and criminal penalties for any unauthorized discharges of oil and other hazardous substances in reportable quantities, and, along with the Oil Pollution Act of 1990 ("OPA"), 33 U.S.C. sec.sec. 2701-2761, imposes substantial potential liability for the costs of removal, remediation and damages. Similarly, the OPA imposes liability for the discharge of oil into or upon navigable waters or adjoining shorelines. Among other things, the OPA raises liability limits, narrows defenses to liability and provides more instances in which a responsible party is subject to unlimited liability. One provision of the OPA requires that offshore facilities establish and maintain evidence of financial responsibility of up to $35.0 million or any amount up to $150.0 million if the EPA determines that a greater amount is justified based on the relative operational, environmental, human health and other risks posed by the quantity or quality of the oil involved. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of an unauthorized discharge of petroleum, its derivatives or other hazardous substances into state waters. Further, the Coastal Zone Management Act ("CZMA"), 16 U.S.C. sec.sec. 1451-1464, authorizes state implementation and development of programs containing management measures for the control of nonpoint source pollution to restore and protect coastal waters.

ENDANGERED SPECIES. The Endangered Species Act ("ESA"), 7 U.S.C. sec. 136, seeks to ensure that activities do not jeopardize endangered or threatened plant and animal species, nor destroy or modify the critical habitat of such species. Under the ESA, certain exploration and production operations, as well as actions by federal agencies or funded by federal agencies, must not significantly impair or jeopardize the species or its habitat. The ESA provides for criminal penalties for willful violations of this act. Other statutes which provide protection to animal and plant species and thus may apply to our operations are the Marine Mammal Protection Act, the Marine Protection and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, and the Migratory Bird Treaty Act. The National Historic Preservation Act, 16 U.S.C. sec. 3470, may impose similar requirements.

COMMUNICATION OF HAZARDS. The Occupational Safety and Health Act, as amended ("OSHA"), 29 U.S.C. sec.sec. 651 et. seq., the Emergency Planning and Community Right-to-Know Act, as amended ("EPCRA"), 42 U.S.C. sec.sec. 11001 et. seq., and comparable state statutes require us to organize and disseminate information to employees, state and local organizations, and the public about the hazardous materials used in its operations and its emergency planning.

EMPLOYEES

Prior to August 1998, we and the general partner depended primarily upon the employees and management services provided by DeepTech International Inc. pursuant to a management agreement, although one of our subsidiaries had 10 full-time employees based in Houma, Louisiana to perform operational functions for its natural gas pipeline and platform operations. Since El Paso Energy's acquisition of our general partner, El Paso Energy through its subsidiaries has provided such services under the management agreement. Accordingly, El Paso Energy hired substantially all of the employees comprising our management team and those employees performing the operational functions. We reimburse the general partner for all reasonable general and administrative expenses and other reasonable expenses incurred by the general partner and its affiliates for or on behalf of us, including, but not limited to, amounts paid by the general partner to El Paso Energy and its affiliates under the management agreement. In addition to the employees provided by affiliates of El Paso Energy under the management agreement, affiliates of El Paso Energy currently have 15 full-time employees based in Houma, Louisiana that spend all their time performing operational functions related to our natural gas pipeline and platform operations. As we continue to operate more facilities, such as Stingray and the facilities under construction, we will require more personnel.

LEGAL PROCEEDINGS

We are involved from time to time in various claims, actions, lawsuits and regulatory matters that have arisen in the ordinary course of business, including various rate cases and other proceedings before the FERC.

In particular, we are a defendant in a lawsuit filed by Transcontinental Gas Pipe Line Corporation ("Transco") in the 157(th) Judicial District Court, Harris County, Texas on August 30, 1996. Transco alleges that, pursuant to a platform lease agreement entered into on June 28, 1994, Transco has the right to expand its facilities and operations on the offshore platform by connecting additional pipeline receiving and appurtenant facilities. We have denied Transco's request to expand its facilities and operations because the lease agreement does not provide for such expansion and because Transco's activities will interfere with the Manta Ray Offshore system and our existing and planned activities on the platform. Transco has requested a declaratory judgment and is seeking damages. The case is set to be tried in November 1999. It is the opinion of management that adequate defenses exist and that the final disposition of this suit individually, and all of our other pending legal proceedings in the aggregate, will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Leviathan and several subsidiaries of El Paso Energy have been made defendants in United States ex rel Grynberg v. El Paso Natural Gas Company, et al. litigation. Generally, the complaint in this motion alleges an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Indian lands, thereby depriving the United States government of royalties. The complaint remains sealed. We believe the complaint is without merit and therefore will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

EL PASO ENERGY'S ACQUISITION OF OUR GENERAL PARTNER

Effective August 14, 1998, El Paso Energy completed the $422.0 million acquisition of our general partner, which became a wholly owned indirect subsidiary of El Paso Energy. The material terms of the acquisition and the related transactions, as they relate to us, are as follows:

(1) El Paso Energy acquired the majority interest of Leviathan Holdings Company, which owns 100% of our general partner, by acquiring DeepTech International Inc. for an aggregate of $365 million, and acquired the minority interests of Leviathan Holdings and two other affiliates of Leviathan Holdings for an aggregate of $55.0 million. Therefore, following those acquisitions by El Paso Energy, El Paso Energy owned an overall 27.3% effective interest in us, comprised of a 1.0% general partner interest, a 25.3% limited partner interest comprised of 6,291,894 common units and a 1.0% nonmanaging membership interest in most of our subsidiaries. Following the closing of the acquisition of the Viosca Knoll interest in June 1999, El Paso Energy (through a subsidiary) acquired an additional 7.2% effective interest in us represented by 2,661,870 common units.

(2) On August 14, 1998, Tatham Offshore, Inc. (an affiliate of ours through August 1998) transferred its remaining assets located in the Gulf of Mexico to us in exchange for the 7,500 shares of Tatham Offshore Series B 9% Senior Convertible Preferred Stock owned by us. We acquired Tatham Offshore's right, title and interest in and to Viosca Knoll Block 817 (subject to an existing production payment obligation), West Delta Block 35, the platform located at Ship Shoal Block 331 and other lease blocks not material to our current operations. Our net cash expenditure for these transactions totaled $0.8 million representing (a) $2.8 million of abandonment costs relating to wells located at Ewing Bank Blocks 914 and 915 offset by (b) $2.0 million of net cash generated from producing properties from January 1, 1998 through August 14, 1998. In addition, we assumed all remaining abandonment and restoration obligations associated with the platform and leases.

MANAGEMENT

OUR DIRECTORS AND EXECUTIVE OFFICERS

We and the general partner utilize the employees of and management services provided by El Paso Energy and its affiliates under our management agreement. We reimburse the general partner for reasonable general and administrative expenses, and other reasonable expenses, incurred by the general partner and its affiliates, for or on our behalf, including, without limitation, fees paid by the general partner to El Paso Energy and its affiliates pursuant to our management agreement. We also reimburse affiliates of our general partner for costs related to insurance and operational personnel that spend all of their time in connection with our operations.

Some of our officers and the general partner's officers and directors are also officers and directors of El Paso Energy and its affiliates. Such officers and directors may spend a substantial amount of time managing the business and affairs of the general partner and El Paso Energy and its affiliates and may face a conflict regarding the allocation of their time between our interests and the other business interests of the general partner and El Paso Energy and its affiliates. Mr. Sims and Mr. Lytal entered into employment agreements with five-year terms with El Paso Energy pursuant to which they would continue to serve as Chief Executive Officer and President, respectively, of the general partner and us. However, pursuant to the terms of their respective employment agreements, Messrs. Sims and Lytal have the right to terminate such agreements upon 30 days notice and El Paso Energy has the right to terminate such agreements under certain circumstances. The general partner may retain, acquire and invest in businesses that compete with us, subject to certain limitations. However, the ability of El Paso Energy and its other affiliates to retain, acquire and invest in businesses that compete with us is not subject to any limitations.

Certain provisions of our partnership agreement contain exculpatory language purporting to (1) limit the liability of the general partner to us and our unitholders and (2) modify the fiduciary duty standards to which the general partner would otherwise be subject under Delaware law. Our partnership agreement provides that (1) any action taken by the general partner consistent with the standards of reasonable discretion set forth in certain definitions in our partnership agreement will not breach any duty of the general partner to us or to our unitholders, (2) in the absence of bad faith by the general partner, the resolution of conflicts of interest by the general partner will not breach our partnership agreement or any standard of care or duty and (3) the general partner and its officers and directors may not be liable to us or to our unitholders for certain actions or omissions which might otherwise be deemed to be a breach of fiduciary duty under Delaware or other applicable state law. Further, the partnership agreement requires us to indemnify the general partner to the fullest extent permitted by law, which indemnification, in light of the exculpatory provisions in the partnership agreement, could result in us indemnifying the general partner for negligent acts.

DIRECTORS AND EXECUTIVE OFFICERS OF THE GENERAL PARTNER

The following table sets forth certain information as of June 30, 1999, regarding our executive officers and the executive officers and directors of the general partner who provide services to us. Each executive officer of the general partner holds the same executive position for us. Directors are elected annually by the general partner's sole stockholder, Leviathan Holdings Company, and hold office until their successors are elected and qualified. Each executive officer named in the following table has been elected to serve until his successor is duly appointed or elected or until his earlier removal or resignation from office.

There is no family relationship among any of the executive officers or directors, and other than described in this prospectus, no arrangement or understanding exists between any executive officer and any other person pursuant to which he was or is to be selected as an officer.

NAME	AGE	POSITION(S)
William A. Wise	53	Director and Chairman of the Board
Grant E. Sims	43	Director and Chief Executive Officer
James H. Lytal	41	Director and President
H. Brent Austin	44	Director and Executive Vice President
Robert G. Phillips	44	Director and Executive Vice President
Keith B. Forman	41	Vice President and Chief Financial Officer
D. Mark Leland	37	Vice President and Controller
Michael B. Bracy	57	Director
H. Douglas Church	61	Director
Malcolm Wallop	66	Director

WILLIAM A. WISE has served as a director and Chairman of the Board of the general partner since August 1998, Chairman of the Board of El Paso Energy since January 1994 and Chief Executive Officer of El Paso Energy since June 1990. Mr. Wise served as President of El Paso Energy from January 1990 until April 1996 and from July 1998 to the present. Mr. Wise served as President and Chief Operating Officer of El Paso Energy from April 1989 to December 1989. From March 1987 until April 1989, Mr. Wise was an Executive Vice President of El Paso Energy and a Senior Vice President of El Paso Energy from January 1984 to February 1987. Mr. Wise is a member of the Boards of Directors of Battle Mountain Gold Company and Chase Bank of Texas and is Chairman of the Board of El Paso Tennessee Pipeline Co.

GRANT E. SIMS has served as a director of the general partner since July 1995 and as our Chief Executive Officer and the Chief Executive Officer of general partner since August 1994. Mr. Sims served as our President and President of the general partner from March 1994 through June 1995. In addition, Mr. Sims has served as a director and Senior Vice President of DeepTech International Inc. since July 1993 and served as a director of Offshore Gas Marketing, Inc., a subsidiary of DeepTech, from December 1992 to March 1994. Prior to his employment with DeepTech, Mr. Sims spent ten years with Transco in various capacities, most recently directing Transco's non-jurisdictional natural gas activities.

JAMES H. LYTAL has served as a director of the general partner since July 1995 and as our President and President of the general partner since August 1994. He served as our Senior Vice President and Senior Vice President of the general partner from August 1994 to June 1995. Prior to joining us, Mr. Lytal was Vice President -- Business Development for American Pipeline Company from December 1992 to August 1994. Prior thereto, Mr. Lytal served as Vice President -- Business Development for United Gas Pipe Line Company from March 1991 to December 1992. Prior thereto, Mr. Lytal has served in various capacities in the oil and natural gas exploration and production and natural gas pipeline industries with Texas Oil and Gas, Inc. and American Pipeline Company from September 1980 to March 1991.

H. BRENT AUSTIN has served as a director and an Executive Vice President of the general partner and as our Executive Vice President since August 1998. Mr. Austin has served as an Executive Vice President of El Paso Energy since May 1995 and as the Chief Financial Officer of El Paso Energy since April 1992. He served as the Senior Vice President of El Paso Energy from April 1992 to May 1995. He served as the Vice President, Planning and Treasurer of Burlington Resources Inc. from November 1990 to March 1992 and Assistant Vice President, Planning of Burlington Resources from January 1989 to October 1990. Mr. Austin is a member of the Board of Directors of El Paso Tennessee Pipeline Co.

ROBERT G. PHILLIPS has served as a director and an Executive Vice President of the general partner and as our Executive Vice President since August 1998. Mr. Phillips has served as President of El Paso Field

Services Company since June 1997. He served as President of El Paso Energy Resources Company from December 1996 to June 1997, President of El Paso Field Services Company from April 1996 to December 1996 and Senior Vice President of El Paso Energy from September 1995 to April 1996. For more than five years prior thereto, Mr. Phillips was Chief Executive Officer of Eastex Energy, Inc.

KEITH B. FORMAN has served as our Chief Financial Officer and Chief Financial Officer of the general partner since January 1992 and served as a director of the general partner from July 1992 to August 1998. Prior to joining us, Mr. Forman served as Vice President of the Natural Gas Pipeline Group of Manufacturers Hanover Trust Company which he joined in 1982. His account responsibility included interstate natural gas transmission companies and natural gas gathering companies.

D. MARK LELAND has served as our Vice President and Controller and Vice President and Controller of the general partner since August 1998 and as Vice President of El Paso Field Services Company since September 1997. He served as Director of Business Development for El Paso Field Services Company from September 1994 to September 1997. For more than five years prior thereto, Mr. Leland served in various capacities in the finance and accounting functions of El Paso Energy.

MICHAEL B. BRACY has served as a director of the general partner since October 1998. From January 1993 to August 1997, Mr. Bracy served as a director, Executive Vice President and Chief Financial Officer of NorAm Energy Corp. (formerly Arkla, Inc.) and as Executive Vice President and Chief Financial Officer of NorAm from December 1991 to January 1993. For seven years prior thereto, Mr. Bracy served in various executive capacities with NorAm. From December 1977 to October 1984, Mr. Bracy held various executive financial positions with El Paso Energy and prior thereto, Mr. Bracy served in various capacities with The Chase Manhattan Bank. Mr. Bracy is a member of the Board of Directors of Itron, Inc.

H. DOUGLAS CHURCH has served as a director of the general partner since January 1999. From January 1994 to December 1998, Mr. Church served as the Senior Vice President, Transmission, Engineering and Environmental for a subsidiary of, Duke Energy Corporation, Texas Eastern Transmission Company. For thirty-two years prior thereto, Mr. Church served in various engineering and operating capacities with Texas Eastern, Panhandle Eastern Corporation and Transwestern Pipeline Company. Mr. Church is a past member and Chairman of the Board of Directors of Southern Gas Association and Boys and Girls Country of Houston, Inc.

MALCOLM WALLOP has served as a director of the general partner since August 1998 and as a director of El Paso Energy since February 1995. Mr. Wallop became Chairman of Western Gulf Strategy Group on January 1, 1999. Since January 1996, Mr. Wallop has served as President for Frontiers of Freedom Foundation, a political foundation. For eighteen years prior thereto, Mr. Wallop was a member of the United States Senate. He is a member of the Board of Directors of Hubbell Inc. and Sheridan State Bank.

COMPENSATION OF DIRECTORS

Directors of the general partner are entitled to reimbursement for their reasonable out-of-pocket expenses in connection with their travel to and from, and attendance at, meetings of the Board or committees thereof. Mr. Paul Thompson III, Mr. George L. Ball and Mr. William A. Bruckmann, III, directors of the general partner until their resignation on August 14, 1998, were paid an annual fee of $36,000 plus $1,000 per meeting attended. Current non-employee directors are paid an annual fee of $30,000. Officers of the general partner and our officers are elected by, and serve at the discretion of, the Board.

Pursuant to our former non-employee director compensation arrangements, we were obligated to pay each non-employee director 2.5% of the general partner's Incentive Distribution as a profit participation fee. During the year ended December 31, 1998, we paid the Messrs. Thompson, Ball and Bruckmann a total of $600,000 as a profit participation fee. In connection with El Paso Energy's acquisition of Leviathan, Messrs. Thompson, Ball and Bruckmann resigned and the compensation arrangements were terminated.

In August 1998, we adopted the 1998 Unit Option Plan for Non-Employee Directors to provide us with the ability to issue unit options to attract and retain the services of knowledgeable directors. Unit options to purchase a maximum of 100,000 common units may be issued pursuant to this plan. Under this plan, we granted (1) 1,500 unit options to Mr. Wallop in August 1998 to acquire an equal number of common units at $27.34375 per unit, (2) 1,500 unit options to Mr. Bracy in October 1998 to acquire an equal number of common units at $25.00 per unit and (3) 1,500 unit options to Mr. Church in January 1999 to acquire an equal number of common units at $20.625 per unit. Each unit option vests immediately at the date of grant and shall expire ten years from such date, but shall be subject to earlier termination in the event that Messrs. Wallop, Bracy and Church cease to be a director of the 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. This plan is administered by a management committee consisting of the Chairman of the Board and such other senior officers of the general partner or its affiliates as the Chairman of the Board shall designate.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

We do not currently have a compensation committee or another committee performing similar functions, and all such matters which would be considered by such committee are acted upon by the full Board of Directors. The Board of Directors, administers and interprets the Omnibus Plan. See "Management -- Executive Compensation -- Omnibus Plan" beginning on page 75.

AUDIT AND CONFLICTS COMMITTEE

Currently, Messrs. Bracy, Church and Wallop, who are neither officers nor employees of the general partner nor any of its affiliates, serve as the Audit and Conflicts Committee of the Board of Directors of the general partner and of us. Mr. Wallop is a director of El Paso Energy. Through August 14, 1998, Messrs. Thompson, Ball and Bruckmann, who were neither officers nor employees of the general partner nor any of its affiliates, served as the Audit and Conflicts Committee.

The Audit and Conflicts Committee provides two primary services. First, it advises the Board of Directors in matters regarding the system of internal controls and the annual independent audit, and reviews our policies and practices, as well as those of the general partner. Second, the Audit and Conflicts Committee, at the request of the general partner, reviews specific matters as to which the general partner believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the general partner is fair and reasonable to us. Except as otherwise required by the rules of the NYSE, the Audit and Conflicts Committee only reviews matters concerning potential conflicts of interest at the request of the general partner, which has sole discretion to determine which such matters to submit to that committee. Any such matters approved by a majority vote of the Audit and Conflicts Committee will be conclusively deemed (1) to be fair and reasonable to us, (2) approved by all of our limited partners and (3) not a breach by the general partner of any duties it may owe to us. However, it is possible that such procedure in itself may constitute a conflict of interest.

COMPENSATION OF THE GENERAL PARTNER

The general partner receives no remuneration in connection with our management other than: (1) distributions in respect of its general and limited partner interests in us and its nonmanaging interest in certain of our subsidiaries; (2) incentive distributions in respect of its general partner interest, as provided in our partnership agreement; and (3) reimbursement for all direct and indirect costs and expenses incurred on our behalf, all selling, general and administrative expenses incurred by the general partner for or on our behalf and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, us, including, but not limited to, the management fees paid by the general partner to El Paso Energy and its affiliates under our management agreement.

EXECUTIVE COMPENSATION

Our executive officers (who are also executive officers of the general partner) are compensated by El Paso Energy (and, prior to consummation of El Paso Energy's acquisition of Leviathan, were compensated by Leviathan's parent) and do not receive compensation from the general partner or us for their services in such capacities with the exception of awards pursuant to the Unit Rights Appreciation Plan and Omnibus Plan discussed below.

UNIT RIGHTS APPRECIATION PLAN

In 1995, we adopted the Unit Rights Appreciation Plan to provide us with the ability of making awards of unit rights to certain officers and employees of the general partner or its affiliates as an incentive for these individuals to continue in the service of us or our affiliates. Under the Unit Rights Plan, we granted 1.2 million unit rights to certain officers and employees of the general partner or its affiliates that provided for the right to purchase, or realize the appreciation of, a preference unit or a common unit, pursuant to the provisions of the Unit Rights Plan. The Unit Rights Plan was administered by a committee of the Board of Directors of the general partner comprised of two or more non-employee directors. The aggregate number of rights that could have been issued pursuant to the Unit Rights Plan could not exceed 400,000 rights per calendar year and 4 million rights over the term of that plan, subject to adjustment. No participant could have been granted more than 400,000 rights in any calendar year. The exercise price covered by the rights granted pursuant to that plan was the closing price of the preference units as reported on the NYSE on the date on which rights were granted pursuant to that plan.

The exercise prices covered by these rights granted pursuant to this plan ranged from $15.6875 to $21.50, the closing prices of the preference units as reported on the NYSE on the grant date of the respective rights. As a result of the "change of control" occurring upon the closing of El Paso Energy's acquisition of Leviathan, the rights fully vested and the holders of those rights elected to be paid $8.6 million, the amount equal to the difference between the grant price of those rights and the average of the high and the low sales price of the common units on the date of exercise. Upon the exercise of all of the rights outstanding, that plan was terminated. We replaced that plan with the Omnibus Plan described below.

OMNIBUS PLAN

In August 1998, we adopted the 1998 Omnibus Compensation Plan to provide us 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. The Plan is administered by the Board. The Board interprets, prescribes, amends and rescinds rules relating to the Omnibus Plan, selects eligible participants, makes grants to participants who are not Section 16 insiders pursuant to the Exchange Act, and takes all other actions necessary for the Omnibus Plan administration, which actions shall be final and binding upon all the participants.

In August 1998, we granted 930,000 unit options to employees of our general partner to purchase an equal number of common units at $27.1875 per unit pursuant to the Omnibus Plan. These unit options, none of which are exercisable, remain outstanding as of April 30, 1999.

REPORT FROM COMPENSATION COMMITTEE REGARDING EXECUTIVE COMPENSATION

Because we do not have a compensation committee or another committee performing similar functions, this report is presented by the full Board of Directors. The Board of Directors is responsible for establishing appropriate compensation goals for the knowledgeable officers and key management personnel working for us and evaluating the performance of such officers and personnel in meeting such goals.

The goals of the Board of Directors in administering the Omnibus Plan are as follows:

(1) To fairly compensate the knowledgeable officers and key management personnel working for us and our affiliates for their contributions to our short-term and long-term performance.

(2) To allow us to attract, motivate and retain the management personnel necessary to our success by providing an Omnibus Plan comparable to that offered by companies with which we compete for such management personnel.

The elements of the Omnibus Plan described above are implemented and periodically reviewed and adjusted by the Board of Directors. The awards made under the Omnibus Plan are determined based on individual performance, experience and comparison with awards made by our industry peers and other companies in similar industries with comparable revenue while linking such awards to our achievement of certain financial goals.

SUMMARY COMPENSATION TABLE

The following table sets forth information concerning the annual compensation earned by our Chief Executive Officer and each of our other four most highly compensated executive officers whose annual salary and bonus from us during the year ended December 31, 1998 exceeded $100,000:

		ANNUAL COMPENSATION(2)				LONG-TERM COMPENSATION AWARDS	
NAME/PRINCIPAL POSITION	FISCAL YEAR	SALARY ($)	BONUS ($)	MARKET VALUE OF UNITS ISSUED	OTHER ANNUAL COMPENSATION ($)	OPTIONS (#)	ALL OTHER COMPENSATION ($)
Grant E. Sims................	1998	--	--	--	--	215,000(3)	--
Chief Executive Officer	1997	--	--	--	--	125,000(4)	--
	1996	--	--	--	--	90,000(4)	--
James H. Lytal...............	1998	--	--	--	--	215,000(3)	--
President	1997	--	--	--	--	125,000(4)	--
	1996	--	--	--	--	90,000(4)	--
Keith B. Forman..............	1998	--	--	--	--	215,000(3)	--
Chief Financial Officer	1997	--	--	--	--	125,000(4)	--
	1996	--	--	--	--	90,000(4)	--
John H. Gray(1)..............	1998	--	--	--	--	--	--
Chief Operating Officer	1997	--	--	--	--	125,000(4)	--
	1996	--	--	--	--	90,000(4)	--
Donald V. Weir(1)............	1998	--	--	--	--	--	--
Vice President	1997	--	--	--	--	--	--
	1996	--	--	--	--	--	--
T. Darty Smith...............	1998	--	--	--	--	70,000(3)	--
Vice President	1997	--	--	--	--	50,000(4)	--
	1996	--	--	--	--	20,000(4)	--
Bart H. Heijermans...........	1998	--	--	--	--	40,000(3)	--
Vice President	1997	--	--	--	--	--	--
	1996	--	--	--	--	--	--

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(1) John H. Gray, our former Chief Operating Officer, and Donald V. Weir, our former Vice President, resigned their positions in connection with the consummation of El Paso Energy's acquisition of our general partner on August 14, 1998.

(2) Other than awards made under our incentive arrangements, all other compensation was paid by El Paso Energy and/or our previous parent.

(3) Issued pursuant to the Omnibus Plan.

(4) Issued pursuant to the Unit Rights Plan.

OPTION GRANTS

The following table sets forth certain information concerning the unit options granted to the named officers during the year ended December 31, 1998:

NAME	NUMBER OF COMMON UNITS UNDERLYING OPTIONS GRANTED	PERCENT OF TOTAL OPTIONS GRANTED TO EMPLOYEES IN FISCAL YEAR	EXERCISE OR BASE PRICE ($/SH)	EXPIRATION DATE	POTENTIAL REALIZABLE VALUE AT ASSUMED ANNUAL RATES OF UNIT PRICE APPRECIATION FOR OPTION TERM 5% ($)	10% ($)
Grant E. Sims........	215,000(1)	23%	$27.1875	8/14/2008	$3,676,086	$9,315,923
James H. Lytal.......	215,000(1)	23%	$27.1875	8/14/2008	$3,676,086	$9,315,923
Keith B. Forman......	215,000(1)	23%	$27.1875	8/14/2008	$3,676,086	$9,315,923
T. Darty Smith.......	70,000(1)	8%	$27.1875	8/14/2008	$1,196,865	$3,033,091
Bart H. Heijermans...	40,000(1)	4%	$27.1875	8/14/2008	$ 683,923	$1,733,195

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(1) These unit options were issued pursuant to the Omnibus Plan and are not immediately exercisable. One half of the unit options are considered vested and exercisable one year after at the date of grant and the remaining one-half of the units options are considered vested and exercisable one year after the first anniversary of the date of grant. The unit options shall expire 10 years from such grant date, but shall be subject to earlier termination in the event that a participant ceases employment with the general partner for retirement or disability, in which case the unit options expire 36 months after such date; for termination without cause, one year after such date; for voluntary termination, three months after such date; and death, twelve months after such date.

OPTION EXERCISES AND YEAR-END VALUE TABLE

The following table sets forth certain information concerning the unit options held by the relevant officers at December 31, 1998 or exercised by those officers during the year then ended:

NAME	SHARES ACQUIRED ON EXERCISE(#)	VALUE REALIZED($)	NUMBER OF EXERCISABLE/ UNEXERCISABLE(2)	VALUE OF UNEXERCISED IN-THE-MONEY OPTIONS AT FISCAL YEAR-END EXERCISABLE/ UNEXERCISABLE
Grant E. Sims........................	215,000(1)	$1,745,938(1)	-- /215,000	-$-/$--
James H. Lytal.......................	215,000(1)	1,745,938(1)	-- /215,000	--/ --
Keith B. Forman......................	215,000(1)	1,745,938(1)	-- /215,000	--/ --
T. Darty Smith.......................	70,000(1)	416,875(1)	-- /70,000	--/ --
Bart H. Heijermans...................	--	--	-- /40,000	--/ --

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(1) As a result of the "change of control" occurring upon El Paso Energy's acquisition of our general partner, the rights issued pursuant to the Unit Rights Plan fully vested and the holders of the rights elected to be paid the amount equal to the difference between the grant price of the right and the average of the high and the low sales price of the common units on the date of exercise.

(2) All unexercisable options in this column relate to options issued pursuant to the Omnibus Plan.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

MANAGEMENT FEES

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 our direction are currently employed by El Paso Energy. Under a management agreement between a subsidiary of El Paso Energy and our general partner, a management fee is charged to our general partner which is intended to approximate an allocation for the costs of resources allocated by El Paso Energy and its affiliates in connection with operational, financial, accounting and administrative matters. The management agreement expires on June 30, 2002, and may be terminated thereafter upon 90 days notice by either party. Under our partnership agreement, our general partner is reimbursed for all reasonable general and administrative expenses and other reasonable expenses that it and its affiliates incur on our behalf, including amounts payable by our general partner to a subsidiary of El Paso Energy under the management agreement.

In connection with El Paso Energy's acquisition of our general partner, our general partner amended its management agreement to provide for a monthly management fee of $775,000. Prior to that, the management fee represented an allocation of costs attributable to our business, primarily based on a time and space methodology. Effective November 1, 1995, July 1, 1996 and July 1, 1997, primarily as a result of our increased activities, the annual management fee was 45.3%, 54.0% and 52.0% of such costs. Our general partner charged us $9.3 million, $8.1 million and $6.6 million under our management agreement for the years ended December 31, 1998, 1997 and 1996, and $4.6 million and $4.7 million for the six months ended June 30, 1998, and 1999.

In addition, our general partner must reimburse El Paso Energy and its affiliates for certain tax liabilities resulting from, among other things, additional taxable income allocated to our general partner due to (1) the issuance of additional preference units in 1994 and (2) the investment of such proceeds in additional acquisitions or construction projects. During the years ended December 31, 1998, 1997 and 1996, our general partner charged us $489,000, $713,000 and approximately $1.2 million for additional taxable income allocated to the general partner.

PLATFORM ACCESS AND TRANSPORTATION AGREEMENTS

VIOSCA KNOLL. For the years ended December 31, 1998, 1997 and 1996, we received approximately $1.1 million, $2.0 million and $1.9 million from Tatham Offshore as platform access and production handling fees related to our platform located in Viosca Knoll Block 817.

For the years ended December 31, 1998, 1997 and 1996, we charged Viosca Knoll approximately $2.4 million, $2.1 million and $249,000 for expenses and platform access fees related to the Viosca Knoll Block 817 platform.

In addition, for the years ended December 31, 1998, 1997 and 1996, Viosca Knoll reimbursed us $152,000, $47,000 and $254,000 for costs we incurred in connection with the acquisition and installation of a booster compressor on our Viosca Knoll Block 817 platform.

During the years ended December 31, 1998, 1997 and 1996, Viosca Knoll charged us approximately $1.9 million, $3.9 million and $3.2 million for transportation services related to transporting production from the Viosca Knoll Block 817 lease.

GARDEN BANKS. During the years ended December 31, 1998, 1997 and 1996, Poseidon charged us approximately $1.4 million, $2.0 million and $1.1 million for transportation services related to transporting production from the Garden Banks Block 72 and 117 leases.

OTHER

We have agreed to sell all of our oil and natural gas production to Offshore Gas Marketing, Inc. a wholly owned subsidiary of El Paso Energy, on a month to month basis. This agreement provides Offshore

Gas Marketing fees equal to 2.0% of the sales value of crude oil and condensate and $0.015 per dekatherm of natural gas for selling our production. During the years ended December 31, 1998, 1997 and 1996, our oil and natural gas sales to Offshore Gas Marketing totaled approximately $31.2 million, $57.8 million and $46.3 million.

We are party to a management agreement with Viosca Knoll under which we charge Viosca Knoll a base fee of $100,000 annually in exchange for providing financial, accounting and administrative services to Viosca Knoll. For each of the years ended December 31, 1998, 1997 and 1996, we charged Viosca Knoll $100,000 in accordance with this agreement.

For the years ended December 31, 1998 and 1997, we charged Manta Ray Offshore approximately $1.3 million and $287,000 under management and operations agreements.

In connection with El Paso Energy's acquisition of our general partner, Mr. Grant E. Sims and Mr. James H. Lytal entered into employment agreements with five year terms with El Paso Energy under which they would continue to serve as our and our general partner's Chief Executive Officer and President, respectively. However, under their respective employment agreements, Messrs. Sims and Lytal have the right to terminate such agreements upon 30 days' advance notice and El Paso Energy has the right to terminate these agreements under certain circumstances.

Under our former non-employee director compensation arrangements, we were obligated to pay each non-employee director 2.5% of the general partner's incentive distribution as a profit participation fee. During the years ended December 31, 1998 and 1997, we paid the three non-employee directors of Leviathan a total of $621,000 and $313,000 as a profit participation fee. As a result of El Paso Energy's acquisition of our general partner, the three non-employee directors resigned and the compensation arrangements were terminated.

We reimburse affiliates of our general partner for costs related to insurance and operational personnel that spend all of their time in connection with our operations. During the last four months of 1998 and the six months ended June 30, 1999, we reimbursed $660,000 and $1.1 million to these affiliates.

Prior to the closing of the offering of our subordinated notes, Viosca Knoll Gathering Company was effectively owned 50.0% by us and 50.0% by El Paso Energy (through a wholly owned subsidiary). In January 1999, we entered into an agreement to acquire an additional 49.0% interest in Viosca Knoll from El Paso Energy, which would result in us owning 99.0% of Viosca Knoll with an option to purchase the remaining 1.0% interest. In exchange for El Paso Energy's contribution of its Viosca Knoll interest, we paid El Paso Energy $79.7 million for the 49.0% interest, comprised of $19.9 in cash and $59.8 million in common units. The acquisition of the Viosca Knoll interest closed on June 1, 1999. Following the closing of the Viosca Knoll transaction and prior to this offering, El Paso Energy's effective ownership interest in us was 34.5%. In addition, at the closing of the Viosca Knoll transaction, El Paso Energy contributed to Viosca Knoll approximately $33.4 million in cash, which equaled 50.0% of the principal amount outstanding under Viosca Knoll's credit facility, and we thereafter repaid and terminated that credit facility.

In October 1998, we purchased a 100% working interest in the Ewing Bank 958 Unit from a wholly owned, indirect subsidiary of El Paso Energy for $12.2 million. For a more detailed description of the Ewing Bank 958 Unit, see "--Business and Properties--Recent Developments, Acquisitions and New Projects--Ewing Bank 958 Unit."

PRINCIPAL UNITHOLDERS

The following table sets forth, as of August 1, 1999, the beneficial ownership of our outstanding equity securities, by (1) each person who we know to beneficially own more than 5.0% of our outstanding units, (2) each director of the general partner and (3) all directors and executive officers of the general partner as a group.

BENEFICIAL OWNER	COMMON UNITS NUMBER	COMMON UNITS PERCENT	PREFERENCE UNITS NUMBER	PREFERENCE UNITS PERCENT
El Paso Energy(1)	(1)	(1)	--	--
Grant E. Sims	33,000(2)	*	--	--
James H. Lytal	6,050(3)	*	--	--
Keith B. Forman	1,000	*	--	--
Robert G. Phillips	1,000	*	--	--
William A. Wise	9,670(4)	*	--	--
H. Brent Austin	1,000	*	--	--
D. Mark Leland	--	--	--	--
Michael B. Bracy	6,500(5)	*	--	--
H. Douglas Church	1,500(5)	*	--	--
Malcolm Wallop	1,500(5)	*	--	--
Executive officers and directors of Leviathan as a group (10 persons)	61,220	*	--	--

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* Less than 1%.

(1) El Paso Energy beneficially owns all of the outstanding capital stock of our general partner, the general partner of Leviathan. The address for our general partner and El Paso Energy is El Paso Energy Building, 1001 Louisiana Street, Houston, Texas 77002. El Paso Energy indirectly owns all of the general partner's outstanding common stock, par value $0.10 per share. The general partner has no other class of capital stock outstanding. As of August 1, 1999, our general partner, through its ownership of 6,291,894 common units, its 1.0% general partner interest and its approximate 1.0% nonmanaging interest in certain of our subsidiaries, effectively owned a 27.3% interest in us. Another subsidiary of El Paso Energy owns 2,661,870 common units. As a result, El Paso Energy effectively owns a 34.5% interest in us.

(2) Mr. Sims disclaims beneficial ownership of 2,000 common units held in trust for his 18 year old son.

(3) Mr. Lytal may be deemed to be the beneficial owner of 34 common units owned by Mr. Lytal's son, a minor.

(4) This number excludes 3,625 units owned by Mr. Wise's children, for which he disclaims beneficial ownership.

(5) Includes the option to acquire 1,500 common units pursuant to the 1998 Unit Option Plan for Non-Employee Directors. See "Management -- Compensation of Directors" beginning on page 73.

DESCRIPTION OF COMMON UNITS

RIGHTS TO DISTRIBUTIONS

GENERAL. Our limited partner interests (common units and preference units) are equity securities entitled (1) to participate in distributions of available cash that may be made from time to time and (2) in the event we liquidate or wind-up, to share in any of our assets remaining after satisfaction of our liabilities. Except to the extent our general partner has earned the right to receive any incentive distributions, we will distribute 98% of our available cash constituting cash from operations to our limited partners in respect of their common units and preference units and 2% of such available cash to our general partner in respect of its 1% general partner interest and its 1% non-managing member interest. Our general partner will become entitled, as an incentive, to a greater share of the distributions of available cash constituting cash from operations to the extent that available cash exceeds specified target levels that are above $0.275 per unit per quarter, as further described below.

Our partnership agreement requires us to distribute all of our "available cash," as such term is defined in our partnership agreement. Generally, "available cash" means, for the applicable quarter, all cash receipts for such quarter and any reductions in reserves established in prior quarters less all cash disbursements made in such quarter and additions to reserves, as determined by our general partner. Our partnership agreement characterizes available cash into two categories--"cash from operations" and "cash from interim capital contributions. This distinction affects the amounts distributed to the unitholders relative to the general partner and the priority of distributions to preference unitholders relative to common unitholders. "Cash from operations," which is determined on a cumulative basis, generally refers to all cash generated by the operations of our business (excluding any cash from interim capital transactions), after deducting related cash operating expenditures, cash debt service payments, cash capital expenditures, reserves and certain other items. "Cash from interim capital transactions" will, generally, be generated only by (1) borrowings and sales of debt securities by us (other than for working capital purposes and other than for goods or services purchased on open account in the ordinary course of business), (2) sales of equity interests in Leviathan for cash and (3) sales or other voluntary or involuntary dispositions of any of our assets for cash (other than inventory, accounts receivable and other current assets and assets disposed of in the ordinary course of business).

Amounts of cash distributed by us on any date from any source will be treated as a distribution of cash from operations, until the sum of all amounts so distributed to the unitholders and to the general partner (including any incentive distributions) equals the aggregate amount of all cash from operations from February 19, 1993 through the end of the calendar quarter prior to such distribution. Any amount of such cash (irrespective of its source) distributed on such date which, together with prior distributions of cash from operations, is in excess of the aggregate amount of all cash from operations from February 19, 1993 through the end of the calendar quarter prior to such distribution will be deemed to constitute cash from interim capital transactions and will be distributed accordingly. If cash that is deemed to constitute cash from interim capital transactions is distributed in respect of each preference unit in an aggregate amount per preference unit equal to the unrecovered capital with respect thereto, the distinction between cash from operations and cash from interim capital transactions will cease, and all cash will be distributed as cash from operations. Because our general partner has no present plans to cause us to use the proceeds from interim capital transactions to pay distributions, our general partner does not currently anticipate that there will be any significant amounts of cash that are deemed to constitute cash from interim capital transactions distributed to the unitholders during the next 18 months.

Capital expenditures that our general partner determines are necessary or desirable to maintain our facilities and operations (as distinguished from capital expenditures made to expand the capacity of such facilities or make strategic acquisitions) will reduce the amount of cash from operations. Therefore, if our general partner were to determine that substantial capital expenditures were necessary or desirable to maintain our facilities, the amount of cash distributions that are deemed to constitute cash from operations would decrease and, if such expenditures were subsequently refinanced and all or a portion of the proceeds distributed to unitholders, the amount of cash distributions deemed to constitute cash from interim capital transactions might increase.

QUARTERLY DISTRIBUTIONS OF AVAILABLE CASH. Our partnership agreement requires us to distribute available cash for each calendar quarter within 45 days after the end of such quarter.

PARTICIPATION IN DISTRIBUTIONS. The holders of our common units are entitled to fully participate in quarterly distributions of available cash constituting cash from operations, subject to the right of our general partner to receive the incentive distributions described below, the right of holders of our preference units to receive minimum quarterly distributions and any arrearages, and the right of holders of any securities we issue after this offering to receive any priority distributions attributable to such securities. The holders of our preference units do not have the right to fully participate in distributions of available cash constituting cash from operations. They do not participate in such distributions in excess of the minimum quarterly distribution amount plus arrearages, if any.

SENIORITY. The common unit distribution rights with respect to available cash constituting cash from operations (1) are subordinate to the right of preference units to receive the minimum quarterly distribution amount (including arrearages) and (2) until the common units receive an amount equal to the minimum quarterly distribution amount (excluding arrearages), are senior to the right of any other unit to receive a share of distributions of available cash constituting cash from operations.

The holders of our preference units are entitled to receive minimum distributions of available cash constituting cash from operations, for each quarter of $0.275 per preference unit, aggregating $1.10 per preference unit on an annualized basis. Such rights are cumulative, and arrearages will accrue.

After the holders of our preference units have received distributions of available cash constituting cash from operations, during any relevant quarter equal to the minimum quarterly distribution amount plus any arrearages, but before any other units may participate in distributions of such available cash during such quarter, the holders of our common units are entitled to receive during such quarter distributions of such available cash, if any, in an amount up to the minimum quarterly distribution amount. However, our common units do not have cumulative distribution participation rights, and no arrearages will accrue.

After our preference unit holders and common unitholders are paid the minimum quarterly distribution amount and any arrearages, holders of our common units are entitled to fully participate in quarterly distributions of available cash, subject to the right of our general partner to receive the incentive distributions described below and the rights of holders of any securities we may issue in the future.

In the future, we may issue unlimited amounts of additional securities that would participate in, or have preferences with respect to, distributions of available cash constituting cash from operations, whether up to or in excess of the minimum quarterly distribution amount.

The minimum quarterly distribution and the specified target levels relating to incentive distributions may be adjusted under certain circumstances in accordance with our partnership agreement.

DISTRIBUTION OF CASH FROM OPERATIONS, UP TO THE MINIMUM QUARTERLY DISTRIBUTION, ON ALL UNITS. Available cash constituting cash from operations in respect of any calendar quarter will be distributed in the following manner:

- first, 98% will be distributed to the preference unitholders, pro rata, and 2% will be distributed to the general partner until there has been distributed in respect of each preference unit an amount equal to the minimum quarterly distribution for such quarter;

- second, 98% will be distributed to the preference unitholders, pro rata, and 2% will be distributed to the general partner until there has been distributed in respect of each preference unit an amount equal to any cumulative arrearages in the minimum quarterly distribution on each preference unit with respect to any prior quarter;

third, 98% will be distributed to the common unitholders, pro rata, and 2% will be distributed to the general partner until there has been distributed in respect of each common unit an amount equal to the minimum quarterly distribution for such quarter; and

thereafter, in the manner described under "--Incentive Distributions" below.

Notwithstanding the foregoing, the minimum quarterly distribution is subject to adjustment as described below.

INCENTIVE DISTRIBUTIONS. Subject to the payment of incentive distributions to the general partner if certain target levels of distributions of available cash constituting cash from operations to preference and common unitholders are achieved, distributions of such available cash are effectively made 98% to the limited partners and 2% to the general partner. As an incentive, in respect of its 2% interest, the general partner's share of such quarterly cash distributions in excess of $0.325 per common unit and less than or equal to $0.375 per common unit will increase to 15%. For such quarterly cash distributions over $0.375 per common unit but no more than $0.425 per common unit, the general partner will receive 25% of such incremental amount, and for all quarterly cash distributions in excess of $0.425 per unit, the 1% general partner interest will receive 50% of the incremental amount. We paid the general partner incentive distributions totaling $11.1 million for the year ended December 31, 1998 and $5.6 million for the six months ended June 30, 1999.

For any calendar quarter with respect to which available cash constituting cash from operations is distributed in respect of both the preference units and the common units in an amount equal to the minimum quarterly distribution of $0.275 per unit, plus any preference unit arrearages, then any additional available cash constituting cash from operations will be allocated between the general partner and the common unitholders at differing percentage rates, which increase the share of such additional available cash allocable to the general partner after common unitholders have received allocations of any such additional available cash constituting cash from operations between the common unitholders and the general partner up to the various target distribution level.

The following table illustrates the percentage allocation of distributions of available cash among the unitholders and our general partner up to the various target distribution levels.

	QUARTERLY DISTRIBUTION AMOUNT PER UNIT UP TO	PERCENT OF MARGINAL AVAILABLE CASH DISTRIBUTED TO	
		COMMON UNITHOLDERS	GENERAL PARTNER
Minimum Quarterly Distribution	$0.275	98%	2%
First Target Distribution	0.325	98%	2%
Second Target Distribution	0.375	85%	15%
Third Target Distribution	0.425	75%	25%
Thereafter	--	50%	50%

DISTRIBUTIONS OF CASH FROM INTERIM CAPITAL TRANSACTIONS. Distributions on any date by us of available cash constituting cash from interim capital transactions will be distributed 98% to preference and common unitholders, pro rata, and 2% to the general partner until a hypothetical holder of a preference unit acquired on February 19, 1993 has received with respect to such preference unit distributions of available cash constituting cash from interim capital transactions in an amount equal to such preference unit's unrecovered capital (being $10.25 per preference unit less any amounts previously distributed as cash from interim capital transactions) plus accrued arrearages, if any. Thereafter, distributions of available cash that constitute cash from interim capital transactions will be distributed as if they were cash from operations, and because the minimum quarterly distribution and first, second and third target distribution levels will have been reduced to zero as described below, the general partner's share of distributions of available cash will increase, in general, to 50% of all distributions of available cash.

After May 5, 2000, any preference units that have not either been redeemed or converted into common units and that have received distributions of cash from interim capital transactions equal to their unrecovered capital plus accrued arrearages, if any, (1) will receive no further distributions, (2) will be treated as if they had been redeemed and (3) will cease to be outstanding for all purposes.

Distributions of cash from interim capital transactions will not reduce the minimum quarterly distribution in the quarter in which they are distributed.

ADJUSTMENT OF THE MINIMUM QUARTERLY DISTRIBUTION AND TARGET DISTRIBUTION LEVELS. The minimum quarterly distribution, unrecovered capital per unit and the first, second and third target distribution levels will be proportionately adjusted upward or downward, as appropriate, in the event of any combination or subdivision of preference units (whether effected by a distribution payable in preference units or otherwise) but not by reason of the issuance of additional preference units for cash or property. For example, in the event of a two-for-one split of the preference units (assuming no prior adjustments), then the minimum quarterly distribution, unrecovered capital for a unit and the first, second and third target distribution levels would each be reduced to 50% of its initial level. In addition, if unrecovered capital is reduced as a result of a distribution of available cash constituting cash from interim capital transactions, the minimum quarterly distribution and the first, second and third target distribution levels will be adjusted downward proportionately, by multiplying each such amount, as the same may have been previously adjusted, by a fraction, the numerator of which is the unrecovered capital immediately after giving effect to such distribution and the denominator of which is the unrecovered capital immediately prior to such distribution. "Unrecovered capital" means, generally, the amount by which $10.25 per preference unit exceeds the aggregate distributions of Cash from Interim Capital Transactions with respect to such unit, as adjusted. For example, the initial unrecovered capital is $10.25 per unit (which was the initial public offering price per preference unit, as adjusted for a two-for-one split); if cash from interim capital transactions of $7.50 per unit is distributed to unitholders (assuming no prior adjustments), then the amount of the minimum quarterly distribution, and of each of the target distribution levels, would be reduced to 26.8% of its initial level. If and when the unrecovered capital is zero, the minimum quarterly distribution and the first, second and third target distribution levels each will have been reduced to zero, and the general partner's share of distributions of available cash will increase, in general, to 50% of all distributions of available cash.

The minimum quarterly distribution and the first, second and third target distribution levels may also be adjusted if legislation is enacted or the interpretation or existing legislation is modified which causes us to become taxable as a corporation or otherwise subjects Leviathan to taxation as an entity for federal income tax purposes. In such event, the minimum quarterly distribution and the first, second and third target distribution levels for each quarter thereafter would be reduced to an amount equal to the product of (1) each of the minimum quarterly distribution and the first, second and third target distribution levels multiplied by (2) one minus the sum of (a) the estimated effective federal income tax rate to which Leviathan is subject as an entity plus (b) the estimated effective overall state and local income tax rate to which Leviathan is subject as an entity for the taxable year in which such quarter occurs. For example, if we were to become taxable as an entity for federal income tax purposes and we became subject to a combined estimated effective federal, state and local income tax rate of 38%, then the minimum quarterly distribution, and each of the target distribution levels, would be reduced to 62% of the amount thereof immediately prior to such adjustment.

DISTRIBUTION OF CASH UPON LIQUIDATION. Following the commencement of our liquidation, our assets will be sold or otherwise disposed of, and the partners' capital account balances will be adjusted to reflect any resulting gain or loss. The proceeds of such liquidation will, first, be applied to the payment of our creditors in the order of priority provided in the partnership agreement and by law, and thereafter, be distributed to the unitholders and our general partner in accordance with their respective capital account balances, as so adjusted.

Partners are entitled to liquidation distributions in accordance with capital account balances. The allocations of gain or loss at the time of liquidation are intended to entitle the holders of outstanding preference units to a preference over the holders of outstanding common units upon our liquidation, to the extent of their Unrecovered Capital and any arrearages. However, you cannot be sure that gain or loss will be sufficient to achieve this result. Preference unitholders will not be entitled to share with the general partner and common unitholders in our assets in excess of such Unrecovered Capital and arrearages. The manner of such adjustment is as provided in the partnership agreement. Any gain (or unrealized gain attributable to assets distributed in kind) will be allocated to the partners as follows:

- first, to the general partner and the holders of units which have negative balances in their capital accounts to the extent of and in proportion to such negative balance;

- second, 98% to the preference unitholders and 2% to the general partner, until the capital account for each preference unit is equal to the sum of the Unrecovered Capital in respect of such preference unit plus any cumulative arrearages then existing in the payment of the minimum quarterly distribution on such preference unit;

- third, 98% to the common unitholders and 2% to the general partner until the capital account for each common unit is equal to the Unrecovered Capital in respect of such common unit;

- fourth, 98% to all unitholders (or, if liquidation occurs after the second anniversary of the preference unit conversion, to all common unitholders) and 2% to the general partner until there has been allocated under this clause fourth an amount per unit equal to (a) the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence, less (b) the amount per unit of any distributions of available cash constituting cash from operations in excess of the minimum quarterly distribution per unit which was distributed 98% to the Common Unitholders and 2% to the general partner for any quarter of our existence;

- fifth, 85% to all unitholders (or, if liquidation occurs after the second anniversary of the preference unit conversion, to all common unitholders) and 15% to the general partner until there has been allocated under this clause fifth an amount per unit equal to (a) the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence, less (b) the amount per unit of any distributions of available cash constituting cash from operations in excess of the first target distribution per unit which was distributed 85% to the common unitholders and 15% to the general partner for any quarter of our existence;

- sixth, 75% to all unitholders (or, if liquidation occurs after the second anniversary of the preference unit conversion, to all common unitholders) and 25% to the general partner until there has been allocated under this clause sixth an amount per unit equal to (a) the excess of the third target distribution per unit over the second target distribution per unit for each quarter of our existence, less (b) the amount per unit of any distributions of available cash constituting cash from operations in excess of the second target distribution per unit which was distributed 75% to the Common Unitholders and 25% to the general partner for any quarter of our existence; and

- thereafter, 50% to all unitholders (or, if liquidation occurs after the second anniversary of the preference unit conversion, to all common unitholders) and 50% to the general partner.

Any loss or unrealized loss will be allocated to the partners: first, in proportion to the positive balances of the preference unitholders' capital accounts until the preference unitholders' capital account balances are reduced to the amount of their Unrecovered Capital plus any arrearages; second, in proportion to the positive balances in the general partner's and the common unitholders' capital accounts until the common unitholders' capital accounts are reduced to zero; third, in proportion to the positive balances in the general partners' and the preference unitholders' capital accounts until the preference unitholders' capital accounts are reduced to zero; and thereafter, to the general partner.

LIMITED CALL RIGHT

If, at any time, non-affiliates of our general partner own 15% or less of the issued and outstanding units of any class (including common units), then our general partner may call, or assign to us or its affiliates our right to call, such remaining publicly-held units at a purchase price equal to the greater of (1) the highest cash price paid by our general partner or its affiliates for any unit purchased within the 90 days preceding the date our general partner mails notice of the election to call the common units or (2) the average of the last reported sales price per common unit over the 20 trading days preceding the date five days before the general partner mails such notice.

VOTING RIGHTS

Our general partner manages and operates our business. Unlike the holders of common stock in a corporation, you will have only limited voting rights on matters affecting our business. You will have no right to elect our general partner on an annual or other continuing basis. Our general partner may not be removed except pursuant to the vote of the holders of at least 55.0% of our outstanding units, including units owned by the general partner and its affiliates. And to the extent our limited partners do have the right to vote on a particular matter, our general partner and its affiliates will be able to exert substantial influence over such vote because of their effective 30.3% ownership of us. You are entitled to vote only on the following matters:

- a merger or consolidation involving us;

- the sale, exchange or other disposition of all or substantially all of our assets;

- our conversion into a corporation for tax purposes;

- the transfer of all of our general partner interest (but not the sale of the general partner);

- the election of any successor general partner upon the current general partner's withdrawal;

- the removal of our general partner;

- our continuation upon an event of dissolution; and

- certain amendments to our partnership agreement.

In addition, unitholders of record will be entitled to notice of, and to vote at, meetings of our limited partners and to act with respect to matters as to which approvals may be solicited. The partnership agreement provides that units held in nominee or street name account will be voted by the broker (or other nominee) pursuant to the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise.

PREEMPTIVE AND DISSENTER'S APPRAISAL RIGHTS

Holders of units do not have preemptive rights and do not have dissenters' rights of appraisal under the partnership agreement or applicable Delaware law in the event of a merger or consolidation involving us or a sale of substantially all of our assets.

TRANSFER AGENT AND REGISTRAR

DUTIES. ChaseMellon Shareholder Services acts as the registrar and transfer agent for the preference and common units and receives a fee from us for serving in such capacities. All fees charged by the transfer agent for transfers and withdrawals of units are borne by us and not by the unitholders, except that fees similar to those customarily paid by stockholders for surety bond premiums to replace lost or stolen certificates, taxes or other governmental charges, special charges for services requested by a unitholder and other similar fees or charges are borne by the affected unitholder. There is no charge to unitholders for disbursements of our distributions of available cash. We indemnify the transfer agent and its agents from certain liabilities.

RESIGNATION OR REMOVAL. The transfer agent may at any time resign, by notice to us, or be removed by us, such resignation or removal to become effective upon the appointment by our general partner of a successor transfer agent and registrar and its acceptance of such appointment. If no successor has been appointed and has accepted such appointment with 30 days after notice of such resignation or removal, our general partner is authorized to act as the transfer agent and registrar until a successor is appointed.

TRANSFER OF UNITS

Until a unit has been transferred on our books, we and the transfer agent may treat the record holder thereof as the absolute owner for all purposes, notwithstanding any notice to the contrary or any notation or other writing on the certificate representing such unit, except as otherwise required by law. Any transfer of a unit will not be recorded by the transfer agent or recognized by us unless certificates representing those units are surrendered. When acquiring units, the transferee of such units:

- is an assignee until admitted as a substituted limited partner;

- automatically requests admission as a substituted limited partner;

- agrees to be bound by the terms and conditions of, and executes, our partnership agreement;

- represents that such transferee has the capacity and authority to enter into our partnership agreement;

- grants powers of attorney to our general partner and any liquidator of us;

- makes the consents and waivers contained in our partnership agreement; and

- certifies that such transferee is an eligible U.S. citizen as required by the FERC.

An assignee will become a limited partner in respect of the transferred units upon the consent of our general partner and the recordation of the name of the assignee on our books and records. Such consent may be withheld in the sole discretion of our general partner. Our units are securities and are transferable according to the laws governing transfers of securities.

In addition to other rights acquired upon transfer, the transferor gives the transferee the right to request admission as a substituted limited partner in respect of the transferred units. A purchaser or transferee of units who does not become a limited partner obtains only (1) the right to assign the units to a purchaser or other transferee and (2) the right to transfer the right to seek admission as a substituted limited partner with respect to the transferred units. Thus, a purchaser or transferee of units who does not meet the requirements of limited partner admission will not be the record holder of such units, will not receive cash distributions unless the units are held in a nominee or street name account and the nominee or broker has ensured that such transferee satisfies such requirements of admission with respect to such units and may not receive certain federal income tax information or reports furnished to unitholders of record.

LIQUIDATION RIGHTS

Following the commencement of our liquidation, assets will be sold or otherwise disposed of, and the partners' capital account balances will be adjusted to reflect any resulting gain or loss. The manner of such adjustment is as provided in our partnership agreement. The proceeds of any liquidation will, first, be applied to the payment of our creditors in the order of priority provided in our partnership agreement and by law, and thereafter, be distributed to the unitholders and our general partner in accordance with their respective capital account balances, as so adjusted.

Partners are entitled to liquidation distributions in accordance with capital account balances. The allocations of gain or loss at the time of liquidation are intended to entitle the holders of outstanding preference units to a preference over the holders of outstanding common units upon our liquidation, to the extent of any unrecovered capital (as defined in our partnership agreement), and any arrearages, applicable thereto. However, no assurance can be given that gain or loss will be sufficient to achieve this result. Further, preference unitholders are not entitled to share with our general partner and other unitholders in our assets in excess of the unrecovered capital and arrearages. Any gain (or unrealized gain attributable to assets distributed in kind) will be allocated to our partners as follows:

first, to the general partner and the holders of units which have negative balances in their capital accounts to the extent of and in proportion to such negative balance;

second, 98% to the preference unitholders and 2% to the general partner, until the capital account for each preference unit is equal to the sum of the unrecovered capital in respect of such preference unit plus any cumulative arrearages then existing in the payment of the minimum quarterly distribution on such preference unit.

third, 98% to the common unitholders and 2% to the general partner until the capital account for each common unit is equal to the unrecovered capital in respect of such common unit;

fourth, 98% to all unitholders (or, if liquidation occurs after August, 2000, to all common unitholders) and 2% to our general partner until there has been allocated under this clause fourth an amount per unit equal to (a) the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence, less (b) the amount per unit of any distributions of available cash constituting "cash from operations" (as defined in our partnership agreement) in excess of the minimum quarterly distribution per unit which was distributed 98% to our common unitholders and 2% to our general partner for any quarter of our existence;

fifth, 85% to all unitholders (or, if liquidation occurs after August, 2000, to all common unitholders) and 15% to our general partner until there has been allocated under this clause fifth an amount per unit equal to (a) the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence, less (b) the amount per unit of any distributions of available cash constituting cash from operations in excess of the first target distribution per unit which was distributed 85% to our common unitholders and 15% to our general partner for any quarter of our existence;

sixth, 75% to all unitholders (or, if liquidation occurs after August 2000, to all common unitholders) and 25% to our general partner until there has been allocated under this clause sixth an amount per unit equal to (a) the excess of the third target distribution per unit over the second target distribution per unit for each quarter our existence, less (b) the amount per unit of any distributions of available cash constituting cash from operations in excess of the second target distribution per unit which was distributed 75% to the common unitholders and 25% to the general partner for any quarter of our existence; and

thereafter, 50% to all unitholders (or, if liquidation occurs after August 2000, to all common unitholders) and 50% to our general partner.

Any loss or unrealized loss will be allocated to the partners: first, in proportion to the positive balances of the preference unitholders' capital accounts until the preference unitholders' capital account balances are reduced to the amount of their unrecovered capital plus any arrearages; second, in proportion to the positive balances in our general partner's and the common unitholders' capital accounts until the common unitholders' capital account balances are reduced to zero; third, in proportion to the positive balances in our general partner's and the preference unitholders' capital accounts until the preference unitholders' capital accounts are reduced to zero; and thereafter, to the general partner.

FURTHER ASSESSMENTS

Generally, limited partners will not be liable for assessments in addition to your initial capital investment in their units. Under certain circumstances, however, limited partners may be required to repay us amounts wrongfully returned or distributed to such limited partners. Under Delaware law, a limited partnership may not make a distribution to a partner to the extent that at the time of the distribution, after giving effect to the distribution, all liabilities of the partnership, other than liabilities to partners on account of their partnership interests and nonrecourse liabilities, exceed the fair value of the assets of the limited partnership. Delaware law provides that a limited partner who receives such a distribution and knew at the time of the distribution that the distribution violated the law will be liable to the limited partnership for the amount of the distribution for three years from the date of the distribution. Under Delaware law, an assignee who becomes a substitute limited partner of a limited partnership is liable for the obligations of his assignor to make contributions to the partnership, except the assignee is not obligated for liabilities that were unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

If it were determined under Delaware law that certain actions which the limited partners may take under our partnership agreement constituted "control" of our business, then our limited partners could be held personally liable for our obligations to the same extent as our general partner.

MODIFICATION OF RIGHTS

In general, amendments which would enlarge the obligations of the limited partners or the general partner require the consent of the limited partner or general partner, as applicable. Notwithstanding the foregoing, our partnership agreement permits our general partner to make certain amendments to our partnership agreement without the approval of any limited partner, including, subject to certain limitations, (1) an amendment that in the sole discretion of our general partner is necessary or desirable in connection with the authorization of additional preference units or other equity securities, (2) any amendment made, the effect of which is to separate into a separate security, separate and apart from the units, the right of preference unitholders to receive any arrearage, and (3) several other amendments expressly permitted in our partnership agreement to be made by our general partner acting alone.

In addition, our general partner may make amendments to our partnership agreement without the approval of any limited partner if such amendments do not adversely affect the limited partners in any material respect, or are required by law or by our partnership agreement.

RELATIONSHIP TO PREFERENCE UNITS

As of August 25, 1999, there were 291,299 preference units outstanding. Preference units have certain rights which are superior to those of common units. These rights include:

- the right to receive a cumulative minimum quarterly distribution of available cash of $0.275 (plus any arrearages) per preference unit before the common units may receive any quarterly distribution; and

- a liquidation preference of the unrecovered capital per preference unit--that is, if we are liquidated, each preference unit must receive a liquidating distribution equal to its unrecovered capital (plus any arrearages on the minimum quarterly distributions) before the common units may receive any liquidating distribution.

RELATIONSHIP TO OTHER UNITS

As of August 25, 1999, there were 26,737,465 common units outstanding. Common units have certain rights which are superior to those of other units that may be issued in the future. These rights include:

- the right to receive a cumulative minimum quarterly distribution of available cash of $0.275 (plus any arrearages) per common unit before the other units may receive any quarterly distribution; and

- a liquidation preference of the unrecovered capital per common unit--that is, if we are liquidated, each common unit must receive a liquidating distribution equal to its unrecovered capital (plus any arrearages on the minimum quarterly distributions) before the other units may receive any liquidating distribution.

CERTAIN OTHER PARTNERSHIP AGREEMENT PROVISIONS

The following paragraphs are a summary of certain provisions of our partnership agreement. The following discussion is qualified in its entirety by reference to our partnership agreement.

PURPOSE

Our stated purposes under our partnership agreement are to serve as the managing member of our subsidiaries and to engage in any business activity permitted under Delaware law. Our general partner is generally authorized to perform all acts deemed necessary to carry out these purposes and to conduct our business. Our partnership existence will continue until December 31, 2043, unless sooner dissolved pursuant to the terms of our partnership agreement.

AUTHORITY OF OUR GENERAL PARTNER

Our general partner has a power of attorney to take certain actions, including the execution and filing of documents, on our behalf and with respect to our partnership agreement. However, our partnership agreement limits the authority of our general partner as follows:

- Without the prior approval of holders of at least a majority of our units, our general partner may not, among other things, (a) sell or exchange all or substantially all of our assets (whether in a single transaction or a series of related transactions) or (b) approve on our behalf the sale, exchange or other disposition of all or substantially all of our assets; however, we may mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without such approval;

- With certain exceptions generally described below under "--Amendment of Partnership Agreement," an amendment to a provision of our partnership agreement generally requires the approval of the holders of at least 66 2/3% of the outstanding units;

- With certain exceptions described below, any amendment that would materially and adversely affect the rights and preference of any type or class of partnership interests in relation to other types or classes of partnership interests will require the approval of the holders of at least a majority of such type or class of partnership interest (excluding those held by our general partner and its affiliates); and

- In general, our general partner may not take any action, or refuse to take any reasonable action, the effect of which would be to cause us to be taxable as a corporation or to be treated as an association taxable as a corporation for federal income tax purposes, without the consent of the holders of at least 66 2/3% of the outstanding units, including the vote of the holders of a majority of the preference units (other than preference units held by our general partner and its affiliates).

WITHDRAWAL OR REMOVAL OF OUR GENERAL PARTNER

Our general partner has agreed not to voluntarily withdraw the general partner on or prior to December 31, 2002 (with limited exceptions described below) without the approval of at least a majority of the remaining outstanding units and an opinion of counsel that (following the selection of a successor) its withdrawal would not result in the loss of limited liability or cause us to be taxed as an entity for federal income tax purposes. However, our general partner may withdraw without such approval of the unitholders, upon 90 days' notice, if more than 50.0% of the outstanding preference units are held or controlled by one person and its affiliates other than the withdrawing general partner and its affiliates.

After December 31, 2002, our general partner may withdraw by giving 90 days' written notice. If an appropriate opinion of counsel cannot be obtained, we would be dissolved as a result of such withdrawal.

Our general partner may not be removed, with or without cause, as general partner except upon approval by the affirmative vote of the holders of not less than 55.0% of the outstanding units, subject to the satisfaction of certain conditions.

In the event of withdrawal of our general partner where such withdrawal violates our partnership agreement or removal of our general partner for "cause," a successor general partner will have the option to acquire the general partner interest of the departing general partner (the "Departing Partner") and, if requested by the Departing Partner, its nonmanaging member interests in our subsidiaries, for a fair market value cash payment. Under all other circumstances where our general partner withdraws or is removed by our limited partners, the Departing Partner will have the option to require the successor general partner to acquire the general partner and nonmanaging member interests of the Departing Partner for a fair market value cash payment.

Our general partner may transfer all, but not less than all, of its general partner interest and its nonmanaging interests in our subsidiaries without the approval of our limited partners (1) to an affiliate of our general partner or (2) upon its merger or consolidation into another entity or the transfer of all or substantially all of its assets to another entity. In the case of any other transfer, in addition to the foregoing requirements, the approval of the holders of at least a majority of the outstanding units is required, excluding for purposes of such determination units held by our general partner and its affiliates. However, no approval of the unitholders is required for transfers of the stock or other securities representing equity interest in our general partner.

REDEMPTION AND LIMITED CALL RIGHT

After approximately August 2000, any or all of the outstanding preference units may be redeemed at any time at our option, exercised in the sole discretion of our general partner, upon at least 30 but not more than 60 days' notice. If, after giving effect to an anticipated redemption, fewer than 1,000,000 preference units would be held by persons other than our general partner and its affiliates, we must redeem all such preference units if we redeem any preference units. The redemption price for each preference unit would be the amount of the "unrecovered capital," which is $10.25 as of the date of this prospectus. Unrecovered capital is more particularly defined in our partnership agreement, but generally is the difference between $10.25 less the amount of available cash from interim capital transactions that has been distributed to a hypothetical preference unit issued on February 19, 1993.

If, at any time, non-affiliates of our general partner own 15% or less of the issued and outstanding units of any class (including common units), then our general partner may call, or assign to us or its affiliates our right to call, such remaining publicly-held units at a purchase price equal to the greater of (1) the highest cash price paid by our general partner or its affiliates for any unit purchased within the 90 days preceding the date our general partner mails notice of the election to call the common units or (2) the average of the last reported sales price per common unit over the 20 trading days preceding the date five days before the general partner mails such notice.

AMENDMENT OF PARTNERSHIP AGREEMENT

Amendments to our partnership agreement may be proposed only by our general partner. Proposed amendments (other than those described below) must be approved by holders of at least 66 2/3% of the outstanding units, except (1) that any amendment that would have a disproportionate material adverse effect on a class of units will require the approval of the holders of at least a majority of the outstanding units (excluding those held by the general partner and its affiliates) of the class so affected or (2) as otherwise provided in our partnership agreement. No provision of our partnership agreement that establishes a percentage of outstanding units required to take any action may be amended or otherwise modified to reduce such voting requirement without the approval of the holders of that percentage of outstanding units constituting the voting requirement sought to be amended.

In general, amendments which would enlarge the obligations of any type or class of our limited partners or our general partner require the consent of such limited partners or general partner, as applicable. Notwithstanding the foregoing, our partnership agreement permits our general partner to make certain amendments to our partnership agreement without the approval of any limited partner, including, subject to certain limitations, (1) an amendment that in the sole discretion of our general partner is necessary or desirable in connection with the authorization of additional preference units or other equity securities, (2) any amendment made, the effect of which is to separate into a separate security, separate and apart from the units, the right of preference unitholders to receive any arrearage, and (3) several other amendments expressly permitted in our partnership agreement to be made by our general partner acting alone.

In addition, our general partner may make amendments to our partnership agreement without the approval of any limited partner if such amendments do not adversely affect the limited partners in any material respect, or are required by law or by our partnership agreement.

No other amendments to our partnership agreement will become effective without the approval of at least 95.0% of the units unless we obtain an opinion of counsel to the effect that such amendment will not cause us to be taxable as a corporation or otherwise taxed as an entity for federal income tax purposes and will not affect the limited liability of any limited partner or any member of our subsidiaries.

MEETINGS; VOTING

Record holders of units on the record date set pursuant to our partnership agreement will be entitled to notice of, and to vote at, meetings of limited partners. Meetings of our limited partners may only be called by our general partner or, with respect to meetings called to remove our general partner, by limited partners owning 55% or more of the outstanding units.

Representation in person or by proxy of two-thirds (or a majority, if that is the vote required to take action at the meeting in question) of the outstanding units of the class for which a meeting is to be held will constitute a quorum at a meeting of limited partners. Except for (a) a proposal for removal or withdrawal of our general partner, (b) the sale of all or substantially all of our assets or (c) certain amendments to our partnership agreement described above, substantially all matters submitted for a vote are determined by the affirmative vote, in person or by proxy, of holders of at least a majority of the outstanding units.

Each record holder of a unit has one vote per unit, according to his percentage interest in us. However, our partnership agreement does not restrict our general partner from issuing units having special or superior voting rights.

INDEMNIFICATION

Our partnership agreement provides that we:

- will indemnify our general partner, any Departing Partner and any person who is or was an officer, director or other representative of our general partner, any Departing Partner or us, to the fullest extent permitted by law, and

- may indemnify, to the fullest extent permitted by law, (a) any person who is or was an affiliate of our general partner, any Departing Partner or us, (b) any person who is or was an employee, partner, agent or trustee of our general partner, any Departing Partner, us or any such affiliate, or (c) any person who is or was serving at our request as an officer, director, employee, partner, member, agent or other representative of another corporation, partnership, joint venture, trust, committee or other enterprise;

(each, as well as any employee, partner, agent or other representative of our general partner, any Departing Partner, us or any of their affiliates, an "Indemnitee") from and against any and all claims, damages, expenses and fines, whether civil, criminal, administrative or investigative, in which any Indemnitee may be involved, or is threatened to be involved, as a party or otherwise, by reason of its status as (1) our general partner, Departing Partner, us or an affiliate of either, (2) an officer, director, employee, partner, agent, trustee or other representative of our general partner, any Departing Partner, us or any of their affiliates or (3) a person serving at our request in any other entity in a similar capacity. Indemnification will be conditioned on the determination that, in each case, the Indemnitee acted in good faith, in a manner which such Indemnitee believed to be in, or not opposed to, our best interests and, with respect to any criminal proceeding, had no reasonable cause to believe its conduct was unlawful.

The above indemnification may result in indemnification of Indemnitees for negligent acts, and may include indemnification for liabilities under the Securities Act. We have been advised that, in the opinion of the Securities and Exchange Commission, such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. Any indemnification under these provisions will be only out of our assets. We are authorized to purchase (or to reimburse our general partner or its affiliates for the cost of) insurance against liabilities asserted against and expenses incurred by such persons in connection with our activities, whether or not we would have the power to indemnify such person against such liabilities under the provisions described above.

GENERAL PARTNER EXPENSES

Our general partner will be reimbursed for its direct and indirect expenses incurred on our behalf on a monthly or other appropriate basis as provided for in our partnership agreement, including, without limitation, expenses allocated to the general partner by its affiliates and payments made by our general partner to El Paso Energy and its affiliates pursuant to the management agreement.

CONVERSION OF PREFERENCE UNITS INTO COMMON UNITS.

From May 14, 1999 until August 12, 1999, the holders of our 1,016,906 outstanding preference units had the right to convert their preference units into an equal number of common units. Holders of 725,607 preference units elected to convert, and holders of 291,299 preference units elected not to convert. This was the second conversion opportunity that we offered to holders of preference units. The third and final conversion option period will occur during substantially the same period in 2000.

During the first and second conversion opportunities, which occurred in 1998 and 1999, the holders of 17,783,701 preference units, representing approximately 98.0% of the preference units issued by us, converted their preference units into common units. As a result of that conversion, the common units then (including the 8,953,764 common units held by our general partner and its affiliates) have become the primary listed security on the NYSE under the symbol "LEV". A total of 291,299 preference units remain outstanding and now trade as our secondary listed security on the NYSE under the symbol "LEV.P".

LIMITED LIABILITY

Assuming that a limited partner does not take part in the control of our business, and that he otherwise acts in conformity with the provisions of our partnership agreement, his liability under Delaware law will be limited, subject to certain possible exceptions, generally to the amount of capital he is obligated to contribute to us in respect of his units plus his share of any of our undistributed profits and assets.

TERMINATION, DISSOLUTION AND LIQUIDATION

Our partnership existence will continue until December 31, 2043, unless sooner terminated pursuant to our partnership agreement. We will be dissolved upon (a) the election of our general partner, if approved by the holders of at least 66 2/3% of the outstanding units, (b) the sale, exchange or other disposition of all or substantially all of our assets and properties, (c) bankruptcy or dissolution of our general partner or (d) withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner (other than by reason of transfer in accordance with our partnership agreement or withdrawal or removal following approval of a successor). Notwithstanding the foregoing, we will not be dissolved if within 90 days after such event our partners agree in writing to continue our business and to the appointment, effective as of the date of such event, of a successor general partner.

Upon a dissolution pursuant to clause (c) or (d) above, the holders of at least 66 2/3% of the outstanding units may also elect, within certain time limitations, to reconstitute and continue our business on the same terms and conditions set forth in our partnership agreement by forming a new limited partnership on terms identical to those set forth in our partnership agreement and having as a general partner an entity approved by the holders of at least 66 2/3% of the outstanding units, subject to our receipt of an opinion of counsel that such reconstitution, continuation and approval will not result in the loss of the limited liability of unitholders or cause us, the reconstituted limited partnership or our subsidiaries to be taxable as a corporation or otherwise subject to taxation as an entity for federal income tax purposes.

Upon our dissolution, unless we are reconstituted and continue as a new limited partnership, a liquidator will liquidate our assets and apply the proceeds of the liquidation in the order of priority set forth in our partnership agreement. The liquidator may defer liquidation or distribution of our assets and/or distribute assets to partners in kind if it determines that a sale or other disposition of our assets would be unsuitable.

OTHER UNITHOLDER RIGHTS AND OBLIGATIONS

In addition to the information above, you will find other rights and obligations arising under our partnership agreement described in this prospectus in the sections entitled "The Offering" beginning on page 7 and "Description of Common Units" beginning on page 81.

INCOME TAX CONSIDERATIONS

The tax consequences to you of an investment in common units will depend in part on your own tax circumstances. You should therefore consult your own tax advisor about the federal, state, local and foreign tax consequences to you of an investment in common units.

This section is a summary of material tax considerations that may be relevant to prospective unitholders and, to the extent set forth below under "--Legal Opinions and Advice," expresses the opinion of Akin, Gump, Strauss, Hauer & Feld, L.L.P., counsel to us and our general partner, insofar as it relates to matters of law and legal conclusions. This section is based upon current provisions of the Internal Revenue Code of 1986, as amended (the "Code"), existing and proposed regulations thereunder and current administrative rulings and court decisions, all of which are subject to change, possibly retroactively. Subsequent changes in such authorities may cause the tax consequences to vary substantially from the consequences described below.

No attempt has been made in the following discussion to comment on all federal income tax matters affecting us or you. Moreover, the discussion focuses on unitholders who are individual citizens or residents of the U.S. and has only limited application to corporations, estates, trusts, non-resident aliens or other unitholders subject to specialized tax treatment (such as tax-exempt institutions, foreign persons, individual retirement accounts, REITs or mutual funds). Accordingly, you should consult, and should depend on, your own tax advisor in analyzing the federal, state, local and foreign tax consequences peculiar to you of the ownership or disposition of units.

LEGAL OPINIONS AND ADVICE

Our counsel is of the opinion that, based on the accuracy of the representations and subject to the qualifications set forth in the detailed discussion that follows, for federal income tax purposes (1) we will be treated as a partnership, and (2) owners of units (with certain exceptions, as described in "--Limited Partner Status" below) will be treated as our partners. In addition, all statements as to matters of law and legal conclusions contained in this section, unless otherwise noted, reflect the opinion of our counsel.

We have not requested and will not request a ruling from the IRS, and the IRS has made no determination, with respect to the foregoing issues or any other matter affecting us or you. An opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Thus, no assurance can be provided that, if contested by the IRS, a court would agree with the opinions and statements set forth herein. Any such contest with the IRS may materially and adversely impact the market for our units and the prices at which they trade. In addition, the costs of any contest with the IRS will be borne directly or indirectly by the unitholders and our general partner. Furthermore, no assurance can be given that our treatment or the treatment of an investment in us will not be significantly modified by future legislative or administrative changes or court decisions. Any such modification may or may not be retroactively applied.

For the reasons hereinafter described, our counsel has not rendered an opinion with respect to the following specific federal income tax issues:

(1) the treatment of a unitholder whose units are loaned to a short seller to cover a short sale of units (see "--Tax Treatment of Operations--Treatment of Short Sales"),
(2) whether a unitholder acquiring units in separate transactions must maintain a single aggregate adjusted tax basis in his units (see "--Disposition of Units--Recognition of Gain or Loss"),
(3) whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (see "--Disposition of Units--Allocations Between Transferors and Transferees"), and;
(4) whether our method for depreciating Section 743 adjustments is sustainable (see "--Tax Treatment of Operations--Section 754 Election").

TAX RATES

The top effective income tax rate for individuals for 1999 is 39.6%. In general, net capital gains of an individual are subject to a maximum 20% tax rate if the asset giving rise to gain was held for more than 12 months at the time of disposition.

PARTNERSHIP STATUS

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his allocable share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, regardless of whether cash distributions are made. Distributions by a partnership to a partner are generally not taxable unless the amount of cash distributed is in excess of the partner's adjusted basis in his partnership interest immediately before the distribution.

We have not requested and will not request a ruling from the IRS, and the IRS has made no determination, as to our status as a partnership for federal income tax purposes. Instead we have relied on the opinion of our counsel that, based upon the Code, the regulations thereunder, published revenue rulings and court decisions, we will be classified as a partnership for federal income tax purposes.

In rendering its opinion, our counsel has relied on certain factual representations made by us and our general partner. Such factual matters are as follows:

- We will not elect to be treated as an association or corporation;

- We will be operated in accordance with (1) all applicable partnership statutes, (2) our partnership agreement, and (3) the description thereof in this prospectus;

- For each taxable year, more than 90% of our gross income will be income from sources that our counsel has opined or may opine is "qualifying income" within the meaning of Section 7704(d) of the Code;

- Each futures contract entered into by us for the purchase or sale of natural gas or crude oil will be identified as a hedging transaction pursuant to Treasury Regulation Section 1.1221-2(e)(1); and

- Gain or loss resulting from our future transactions will be treated as an adjustment in the computation of cost of goods sold with respect to sales of crude oil for federal income tax purposes.

- Prior to January 1, 1997 our general partner had at all times while acting as our general partner either (i) in the aggregate as a general and limited partner at least a 20% interest in the capital and 19% of our outstanding units and will be acting for its own account and not as a mere agent of the limited partners, or (ii) assets (excluding any interest in, or notes or receivables due from, us or our operating subsidiaries), the fair market value of which exceeds its liabilities by the amount of at least 5% of the fair market value of all partnership interests outstanding immediately after the initial public offering of preference units, plus 5% of any additional net capital contributions to us made after the initial public offering.

- Prior to January 1, 1992, except as otherwise required by Section 704 of the code, our general partner had an interest in each material item of our and our operating subsidiaries' income, gain, loss, deduction and credit equal to at least 1% at all times during our existence and the existence of our operating companies.

- Prior to January 1, 1992 our general partner has acted independently of our limited partners.

Section 7704 of the Code provides that publicly-traded partnerships will, as a general rule, be taxed as corporations. However, an exception (the "Qualifying Income Exception") exists with respect to publicly-traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income and gains derived from the transportation and marketing, processing, production and development of, and exploration for, natural gas and crude oil, among other activities. Other types of qualifying income include interest (from other than a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. Based upon our representations and the representations of our general partner and a review of the applicable legal authorities, our counsel is of the opinion that at least 90% of our gross income will constitute qualifying income. We estimate that less than 5.0% of our gross income for each taxable year will not constitute qualifying income.

If we fail to meet the Qualifying Income Exception (other than a failure which is determined by the IRS to be inadvertent and which is cured within a reasonable time after discovery), we will be treated as if we had transferred all of our assets (subject to liabilities) to a newly formed corporation (on the first day of the year in which we fail to meet the Qualifying Income Exception) in return for stock in that corporation, and then distributed that stock to our partners in liquidation of their interests in us. This contribution and liquidation should be tax-free to us and unitholders, so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to the unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as either taxable dividend income (to the extent of our current or accumulated earnings and profits) or (in the absence of earnings and profits) a nontaxable return of capital (to the extent of the unitholder's tax basis in his units) or taxable capital gain (after the unitholder's tax basis in his units is reduced to zero). Accordingly, taxation as a corporation would result in a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The discussion below is based on the assumption that we will be classified as a partnership for federal income tax purposes.

LIMITED PARTNER STATUS

Unitholders who have become our limited partners will be treated as our partners for federal income tax purposes. Our counsel is also of the opinion that (a) assignees who have executed and delivered transfer applications and are awaiting admission as limited partners and (b) unitholders whose units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their units will be treated as our partners for federal income tax purposes. As there is no direct authority addressing assignees of units who are entitled to execute and deliver transfer applications and thereby become entitled to direct the exercise of attendant rights, but who fail to execute and deliver transfer applications, our counsel's opinion does not extend to these persons. Furthermore, a purchaser or other transferee of units who does not execute and deliver a transfer application may not receive certain federal income tax information or reports furnished to record holders of units unless the units are held in a nominee or street name account and the nominee or broker has executed and delivered a transfer application with respect to such units.

A beneficial owner of units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to such units for federal income tax purposes. See "--Tax Treatment of Operations--Treatment of Short Sales."

Income, gain, deductions or losses would not appear to be reportable by a unitholder who is not a partner for federal income tax purposes, and any cash distributions received by such a unitholder would therefore be fully taxable as ordinary income. These holders should consult their own tax advisors with respect to their status as our partners for federal income tax purposes.

TAX CONSEQUENCES OF UNIT OWNERSHIP

FLOW-THROUGH OF TAXABLE INCOME

We will pay no federal income tax. Instead, each unitholder will be required to report on his income tax return his allocable share of our income, gains, losses and deductions without regard to whether corresponding cash distributions are received by him. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution. Each unitholder will be required to include in income his allocable share of our income, gain, loss and deduction for our taxable year ending with or within the taxable year of the unitholder.

TREATMENT OF PARTNERSHIP DISTRIBUTIONS

Distributions by us to a unitholder generally will not be taxable to him for federal income tax purposes to the extent of his tax basis in his units immediately before the distribution.

Cash distributions in excess of a unitholder's tax basis generally will be considered to be gain from the sale or exchange of the units, taxable in accordance with the rules described under "--Disposition of Units" below. Any reduction in a unitholder's share of our liabilities for which no partner, including the general partner, bears the economic risk of loss ("nonrecourse liabilities") will be treated as a distribution of cash to that unitholder. To the extent that our distributions cause a unitholder's "at risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. See "--Limitations on Deductibility of Partnership Losses."

A decrease in a unitholder's percentage interest in us because of our issuance of additional units will decrease his share of our nonrecourse liabilities and, thus will result in a corresponding deemed distribution of cash. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his tax basis in his units, if the distribution reduces his share of our "unrealized receivables" (including depreciation recapture) and/or substantially appreciated "inventory items" (both as defined in Section 751 of the Code) (collectively, "Section 751 Assets"). To that extent, he will be treated as having been distributed his proportionate share of the Section 751 Assets and having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income under Section 751(b) of the Code. This income will equal the excess of (1) the non-pro rata portion of the distribution over (2) the unitholder's tax basis for the share of the Section 751 Assets deemed relinquished in the exchange.

RATIO OF TAXABLE INCOME TO DISTRIBUTIONS

We estimate that a purchaser of units in this offering who owns those units from the date of the closing of this offering through December 31, 2001 will be allocated, on a cumulative basis, an amount of federal taxable income for such period that will be approximately 30% of the cash distributed with respect to that period. We further estimate that for taxable years after the taxable year ending December 31, 2001 the taxable income allocable to those unitholders may constitute a significantly higher percentage of cash distributed to them. The foregoing estimates are based upon the assumption that gross income from operations will approximate the amount required to make the minimum quarterly distribution with respect to all units and other assumptions with respect to capital expenditures, cash flow and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and certain tax reporting positions that we have adopted and with which the IRS could disagree. Accordingly, you cannot be sure that the estimates will prove to be correct. The actual percentage could be higher or lower, and any such differences could be material and could materially affect the value of the units.

BASIS OF UNITS

A unitholder's initial tax basis for his units will be the amount he paid for the units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income and by any increases in his share of our nonrecourse liabilities. That basis will be decreased (but not below zero) by distributions from us to him, by his share of our losses, by any decrease in his share of our nonrecourse liabilities and by his share of our expenditures that are not deductible in computing its taxable income and are not required to be capitalized. A limited partner will have no share of our debt which is recourse to the general partner, but will have a share, generally based on his share of profits, of our nonrecourse liabilities. See "--Disposition of Units--Recognition of Gain or Loss."

LIMITATIONS ON DEDUCTIBILITY OF PARTNERSHIP LOSSES

The deduction by a unitholder of his share of our losses will be limited to the tax basis in his units and, in the case of an individual unitholder or a corporate unitholder (if more than 50% of the value of its stock is owned directly or indirectly by five or fewer individuals or certain tax-exempt organizations), to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than his tax basis. A unitholder must recapture losses deducted in previous years to the extent that our distributions cause his at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable to the extent that his tax basis or at risk amount (whichever is the limiting factor) is subsequently increased. Upon the taxable disposition of a unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any excess loss (above such gain) previously suspended by the at risk or basis limitations is no longer utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by any amount of money he borrows to acquire or hold his units if the lender of such borrowed funds owns an interest in us, is related to such a person or can look only to units for repayment. A unitholder's at risk amount will increase or decrease as the tax basis of his units increases or decreases (other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities).

The passive loss limitations generally provide that individuals, estates, trusts and certain closely-held corporations and personal service corporations can deduct losses from passive activities (generally, activities in which the taxpayer does not materially participate) only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly-traded partnership. Consequently, any passive losses generated by us will only be available to offset future income generated by us and will not be available to offset income from other passive activities or investments (including other publicly-traded partnerships) or salary or active business income. Passive losses which are not deductible because they exceed a unitholder's income generated by us may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction to an unrelated party. The passive activity loss rules are applied after other applicable limitations on deductions such as the at risk rules and the basis limitation.

A unitholder's share of our net income may be offset by any suspended passive losses from us, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly-traded partnerships. The IRS has announced that Treasury Regulations will be issued which characterize net passive income from a publicly-traded partnership as investment income for purposes of the limitations on the deductibility of investment interest.

LIMITATIONS ON INTEREST DEDUCTIONS

The deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of such taxpayer's "net investment income." As noted, a unitholder's net passive income from us will be treated as investment income for this purpose. In addition, a unitholder's share of our portfolio income will be treated as investment income. Investment interest expense includes (1) interest on indebtedness properly allocable to property held for investment, (2) our interest expense attributed to portfolio income, and (3) the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income. The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income pursuant to the passive loss rules less deductible expenses (other than interest) directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment.

ALLOCATION OF PARTNERSHIP INCOME, GAIN, LOSS AND DEDUCTION

In general, if we have a net profit, items of income, gain, loss and deduction will be allocated among the general partner and the unitholders in accordance with their respective percentage interests in us. At any time that distributions are made to the preference units and not to the common units, or that incentive distributions are made to our general partner, gross income will be allocated to the recipients to the extent of such distribution. If we have a net loss, items of income, gain, loss and deduction will generally be allocated first, to our general partner and the unitholders in accordance with their respective percentage interests to the extent of their positive capital accounts (as maintained under the partnership agreement) and, second, to our general partner.

As required by Section 704(c) of the Code and as permitted by Regulations thereunder, certain items of our income, deduction, gain and loss will be allocated to account for the difference between the tax basis and fair market value of property contributed to us by our general partner or others ("Contributed Property"). The effect of these allocations to a unitholder will be essentially the same as if the tax basis of the Contributed Property were equal to its fair market value at the time of contribution. In addition, certain items of recapture income will be allocated to the extent possible to the partner allocated the deduction giving rise to the treatment of such gain as recapture income in order to minimize the recognition of ordinary income by some unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in an amount and manner sufficient to eliminate the negative balance as quickly as possible.

Regulations provide that an allocation of items of partnership income, gain, loss or deduction, other than an allocation required by Section 704(c) of the Code to eliminate the difference between a partner's "book" capital account (credited with the fair market value of Contributed Property) and "tax" capital account (credited with the tax basis of Contributed Property) (the "Book-Tax Disparity"), will generally be given effect for federal income tax purposes in determining a partner's distributive share of an item of income, gain, loss or deduction only if the allocation has substantial economic effect. In any other case, a partner's distributive share of an item will be determined on the basis of the partner's interest in the partnership, which will be determined by taking into account all the facts and circumstances, including the partners' relative contributions to the partnership, the interests of the partners in economic profits and losses, the interest of the partners in cash flow and other nonliquidating distributions and rights of the partners to distributions of capital upon liquidation.

Our counsel is of the opinion that allocations under our partnership agreement will be given effect for federal income tax purposes in determining a unitholder's distributive share of an item of income, gain, loss or deduction.

TAX TREATMENT OF OPERATIONS

ACCOUNTING METHOD AND TAXABLE YEAR

We use the year ending December 31 as our taxable year and have adopted the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in income his allocable share of partnership income, gain, loss and deduction for our taxable year ending within or with the taxable year of the unitholder. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his units following the close of our taxable year but before the close of his taxable year must include his allocable share of our income, gain, loss and deduction in income for his taxable year with the result that he will be required to report in income for his taxable year his distributive share of more than one year of our income, gain, loss and deduction. See "--Disposition of Units--Allocations Between Transferors and Transferees."

INITIAL TAX BASIS, DEPRECIATION AND AMORTIZATION

The tax basis of our various assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of such assets. Our assets initially have an aggregate tax basis equal to the consideration we paid for such assets or, with respect to assets we acquired upon our formation or by contribution, the tax basis of the assets in the possession of our general partner or other contributor immediately prior to our formation. The federal income tax burden associated with the difference between the fair market value of property contributed by our general partner or other contributor and the tax basis established for such property will be borne by our general partner or other contributor. See "--Allocation of Partnership Income, Gain, Loss and Deduction."

To the extent allowable, we may elect to use the depletion, depreciation and cost recovery methods that will result in the largest deductions in our early years. We are not be entitled to any amortization deductions with respect to any goodwill conveyed to us on formation. Property subsequently acquired or constructed by us may be depreciated using accelerated methods permitted by the Code.

If we dispose of depreciable property by sale, foreclosure or otherwise, all or a portion of any gain (determined by reference to the amount of depreciation previously deducted and the nature of the property) may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a partner who has taken cost recovery or depreciation deductions with respect to our property may be required to recapture such deductions as ordinary income upon a sale of his units. See "--Allocation of Partnership Income, Gain, Loss and Deduction" and "--Disposition of Units--Recognition of Gain or Loss."

The costs incurred in promoting the issuance of units (i.e. syndication expenses) must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which may be amortized, and as syndication expenses, which may not be amortized. Under recently adopted regulations, underwriting discounts and commissions would be treated as a syndication cost.

SECTION 754 ELECTION

We have made the election permitted by Section 754 of the Code. That election is irrevocable without the consent of the IRS. The election will generally permit us to adjust a unit purchaser's (other than a unit purchaser that purchases units directly from us) tax basis in our assets ("inside basis") pursuant to Section 743(b) of the Code to reflect his purchase price. The Section 743(b) adjustment belongs to the purchaser and not to other partners. (For purposes of this discussion, a partner's inside basis in our assets will be considered to have two components: (1) his share of our tax basis in such assets ("common basis") and (2) his Section 743(b) adjustment to that basis.)

If a partnership elects the remedial allocation method with respect to an item of partnership property (which we may do with respect to certain assets), proposed Treasury regulations under Section 743 of the Code require that the portion of any Section 743(b) adjustment that is attributable to Section 704(c) built in gain must be depreciated over the remaining cost recovery period for the Section 704(c) built in gain. Nevertheless, the proposed regulations under Section 197 indicate that the Section 743(b) adjustment attributable to an amortizable Section 197 intangible should be treated as a newly-acquired asset placed in service in the month when the purchaser acquires the unit. Under Treasury Regulation Section 1.167(c)-1(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Code rather than cost recovery deductions under Section 168 is generally required to be depreciated using either the straight-line method or the 150% declining balance method. Although the proposed regulations under Section 743 will likely eliminate many of the problems if finalized in their current form, the depreciation and amortization methods and useful lives associated with the Section 743(b) adjustment may differ from the methods and useful lives generally used to depreciate the common basis in such properties. Pursuant to our partnership agreement, we are authorized to adopt a convention to preserve the uniformity of units even if that convention is not consistent with Treasury Regulation Section 1.167(c)-1(a)(6) and Proposed Treasury Regulation Section 1.197-2(g)(3). See "--Uniformity of Units."

Although our counsel is unable to opine as to the validity of such an approach, we intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property (to the extent of any unamortized Book-Tax Disparity) using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of such property, or treat that portion as non-amortizable to the extent attributable to property the common basis of which is not amortizable. This method is consistent with the proposed regulations under Section 743 but is arguably inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6) and Proposed Treasury Regulation Section 1.197-2(g)(3) (neither of which is expected to directly apply to a material portion of our assets). To the extent such Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Regulations and legislative history. If we determine that such position cannot reasonably be taken, we may adopt a depreciation or amortization convention under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. Such an aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to certain unitholders. See "--Uniformity of Units."

The allocation of the Section 743(b) adjustment must be made in accordance with the Code. The IRS may seek to reallocate some or all of any Section 743(b) adjustment not so allocated by us to goodwill which, as an intangible asset, would be amortizable over a longer period of time than some of our tangible assets.

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than such units' share of the aggregate tax basis of our assets immediately prior to the transfer. In such a case, as a result of the election, the transferee would have a higher tax basis in his share of our assets for purposes of calculating, among other items, his depreciation and depletion deductions and his share of any gain or loss on a sale of our assets. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in such units is lower than such unit's share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or adversely by the election.

The calculations involved in the Section 754 election are complex and will be made by us on the basis of certain assumptions as to the value of our assets and other matters. There is no assurance that the determinations made by us will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If such permission is granted, a subsequent purchaser of units may be allocated more income than he would have been allocated had the election not been revoked.

ALTERNATIVE MINIMUM TAX

Each unitholder will be required to take into account his distributive share of any items of our income, gain, deduction or loss for purposes of the alternative minimum tax. The current minimum tax rate for noncorporate taxpayers is 26% on the first $175,000 of alternative minimum taxable income in excess of the exemption amount and 28% on any additional alternative minimum taxable income. Prospective unitholders should consult with their tax advisors as to the impact of an investment in units on their liability for the alternative minimum tax.

VALUATION OF PARTNERSHIP PROPERTY AND BASIS OF PROPERTIES

The federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values of our assets. Although we may from time to time consult with professional appraisers with respect to valuation matters, many of the relative fair market value estimates will be made by us. These estimates are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value are subsequently found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years.

TREATMENT OF SHORT SALES

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of ownership of those units. If so, he would no longer be a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period, any of our income, gain, deduction or loss with respect to those units would not be reportable by the unitholder, any cash distributions received by the unitholder with respect to those units would be fully taxable and all of such distributions would appear to be treated as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units. The IRS has announced that it is actively studying issues relating to the tax treatment of short sales of partnership interests. See also "--Disposition of Units--Recognition of Gain or Loss."

DISPOSITION OF UNITS

RECOGNITION OF GAIN OR LOSS

Gain or loss will be recognized on a sale of units equal to the difference between the amount realized and the unitholder's tax basis for the units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from such sale.

Prior distributions by us in excess of cumulative net taxable income in respect of a unit which decreased a unitholder's tax basis in such unit will, in effect, become taxable income if the unit is sold at a price greater than the unitholder's tax basis in such unit, even if the price is less than his original cost.

Should the IRS successfully contest the convention used by us to amortize only a portion of the Section 743(b) adjustment (described under "--Tax Treatment of Operations--Section 754 Election") attributable to an amortizable Section 197 intangible after a sale by our general partner of units, a unitholder could realize additional gain from the sale of units than had such convention been respected. In that case, the unitholder may have been entitled to additional deductions against income in prior years but may be unable to claim them, with the result to him of greater overall taxable income than appropriate. Our counsel is unable to opine as to the validity of the convention but believes such a contest by the IRS to be unlikely because a successful contest could result in substantial additional deductions to other unitholders.

Gain or loss recognized by a unitholder (other than a "dealer" in units) on the sale or exchange of a unit held for more than one year will generally be taxable as capital gain or loss. Capital gain recognized on the sale of units held for more than 12 months will generally be taxed at a maximum rate of 20%. A portion of this gain or loss (which could be substantial), however, will be separately computed and taxed as ordinary income or loss under Section 751 of the Code to the extent attributable to assets giving rise to depreciation recapture or other "unrealized receivables" or to "inventory items" owned by us. The term "unrealized receivables" includes potential recapture items, including depreciation recapture. Ordinary income attributable to unrealized receivables, inventory items and depreciation recapture may exceed net taxable gain realized upon the sale of the unit and may be recognized even if there is a net taxable loss realized on the sale of the unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a disposition of units. Net capital loss may offset no more than $3,000 of ordinary income in the case of individuals and may only be used to offset capital gain in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis. Upon a sale or other disposition of less than all of such interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method. The ruling is unclear as to how the holding period of these interests is determined once they are combined. If this ruling is applicable to the holders of units, a unitholder will be unable to select high or low basis units to sell as would be the case with corporate stock. It is not clear whether the ruling applies to us because, similar to corporate stock, interests in us are evidenced by separate certificates. Accordingly, our counsel is unable to opine as to the effect such ruling will have on the unitholders. A unitholder considering the purchase of additional units or a sale of units purchased in separate transactions should consult his own tax advisor as to the possible consequences of that ruling.

Some provisions of the Code affect the taxation of certain financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" partnership interest (one in which gain would be recognized if it were sold, assigned or terminated at its fair market value) if the taxpayer or related persons enters into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest or substantially identical property. Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold such position if the taxpayer or related person then acquires the partnership interest or substantially identical property. The Secretary of Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

ALLOCATIONS BETWEEN TRANSFERORS AND TRANSFEREES

In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of units owned by each of them as of the opening of the NYSE on the first business day of the month (the "Allocation Date"). However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction accrued after the date of transfer.

The use of this method may not be permitted under existing Treasury Regulations. Accordingly, our counsel is unable to opine on the validity of this method of allocating income and deductions between the transferors and the transferees of units. If this method is not allowed under the Treasury Regulations (or only applies to transfers of less than all of the unitholder's interest), our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between transferors and transferees (as well as among partners whose interests otherwise vary during a taxable period) to conform to a method permitted under future Treasury Regulations.

A unitholder who owns units at any time during a quarter and who disposes of those units prior to the record date set for a cash distribution with respect to such quarter will be allocated items of our income, gain, loss and deductions attributable to such quarter but will not be entitled to receive that cash distribution.

NOTIFICATION REQUIREMENTS

A unitholder who sells or exchanges units is required to notify us in writing of that sale or exchange within 30 days after the sale or exchange and in any event by no later than January 15 of the year following the calendar year in which the sale or exchange occurred. We are required to notify the IRS of that transaction and to furnish certain information to the transferor and transferee. However, these reporting requirements do not apply with respect to a sale by an individual who is a citizen of the U.S. and who effects the sale or exchange through a broker. Additionally, a transferor and a transferee of a unit will be required to furnish statements to the IRS, filed with their income tax returns for the taxable year in which the sale or exchange occurred, that set forth the amount of the consideration received for the unit that is allocated to goodwill or going concern value of ours. Failure to satisfy these reporting obligations may lead to the imposition of substantial penalties.

CONSTRUCTIVE TERMINATION

We will be considered to have been terminated if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination will result in the closing of our taxable year for all unitholders. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months' taxable income or the inability to include our results in his taxable income for the year of termination. New tax elections required to be made by us, including a new election under Section 754 of the Code, must be made subsequent to a termination, and a termination could result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted prior to the termination.

ENTITY-LEVEL COLLECTIONS

If we are required or elect under applicable law to pay any federal, state or local income tax on behalf of any unitholder or our general partner or any former unitholder, we are authorized to pay those taxes from our funds. Such payment, if made, will be treated as a distribution of cash to the partner on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to current unitholders. We are authorized to amend our partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust subsequent distributions, so that after giving effect to such distributions, the priority and characterization of distributions otherwise applicable under the partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of an individual partner in which event the partner could file a claim for credit or refund.

UNIFORMITY OF UNITS

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of such units. In the absence of uniformity, compliance with a number of federal income tax requirements, both statutory and regulatory, could be substantially diminished. A lack of uniformity can result from a literal application of Treasury Regulation Section 1.167(c)-1(a)(6) and Proposed Treasury Regulation Section 1.197-2(g)(3). Any non-uniformity could have a negative impact on the value of the units. See "--Tax Treatment of Operations--Section 754 Election."

We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of contributed property or adjusted property (to the extent of any unamortized Book-Tax Disparity) using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of such property, or treat that portion as nonamortizable, to the extent attributable to property the common basis of which is not amortizable, consistent with the proposed regulations under Section 743 but despite its inconsistency with Treasury Regulation Section 1.167(c)-1(a)(6) and Proposed Treasury Regulation Section 1.197- 2(g)(3) (neither of which is expected to directly apply to a material portion of our assets). See "--Tax Treatment of Operations--Section 754 Election." To the extent such Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Regulations and legislative history. If we determine that such a position cannot reasonably be taken, we may adopt a depreciation and amortization convention under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to common basis or Section 743(b) basis, based upon the same applicable rate as if they had purchased a direct interest in our property. If such an aggregate approach is adopted, it may result in lower annual depreciation and amortization deductions than would otherwise be allowable to certain unitholders and risk the loss of depreciation and amortization deductions not taken in the year that such deductions are otherwise allowable. We will not adopt this convention if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization convention to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the unitholders. The IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If such a challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. See "--Disposition of Units--Recognition of Gain or Loss."

TAX EXEMPT ORGANIZATIONS AND CERTAIN OTHER INVESTORS

Ownership of units by employee benefit plans, other tax-exempt organizations, nonresident aliens, foreign corporations, other foreign persons and regulated investment companies raises issues unique to such persons and, as described below, may have substantially adverse tax consequences. Employee benefit plans and most other organizations exempt from federal income tax (including individual retirement accounts ("IRAs") and other retirement plans) are subject to federal income tax on unrelated business taxable income. Virtually all of the taxable income derived by such an organization from the ownership of a unit will be unrelated business taxable income and thus will be taxable to such a unitholder.

A regulated investment partnership or "mutual fund" is required to derive 90% or more of its gross income from interest, dividends, gains from the sale of stocks or securities or foreign currency or certain related sources. We do not anticipate that any significant amount of our gross income will include that type of income.

Non-resident aliens and foreign corporations, trusts or estates which hold units will be considered to be engaged in business in the U.S. on account of ownership of units. As a consequence they will be required to file federal tax returns in respect of their share of our income, gain, loss or deduction and pay federal income tax at regular rates on any net income or gain. Generally, a partnership is required to deduct withholding tax on the portion of the partnership's income which is effectively connected with the conduct of a U.S. trade or business and which is allocable to the foreign partners, regardless of whether any actual distributions have been made to such partners. However, under rules applicable to publicly-traded partnerships, we will withhold (currently at the rate of 39.6%) on actual cash distributions made quarterly to foreign unitholders. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to the Transfer Agent on a Form W-8 in order to obtain credit for the taxes withheld. A change in applicable law may require us to change these procedures.

Because a foreign corporation which owns units will be treated as engaged in a U.S. trade or business, such a corporation may be subject to U.S. branch profits tax at a rate of 30%, in addition to regular federal income tax, on its allocable share of our income and gain (as adjusted for changes in the foreign corporation's "U.S. net equity") which are effectively connected with the conduct of a U.S. trade or business. That tax may be reduced or eliminated by an income tax treaty between the U.S. and the country with respect to which the foreign corporate unitholder is a "qualified resident." In addition, such a unitholder is subject to special information reporting requirements under Section 6038C of the Code.

Under a ruling of the IRS a foreign unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized on the disposition of the unit to the extent that the gain is effectively connected with a U.S. trade or business of the foreign unitholder. Apart from the application of ruling, a foreign unitholder will not be taxed or subject to withholding upon the disposition of a unit if that foreign unitholder has held less than 5% in value of the units during the five-year period ending on the date of the disposition and if the units are regularly traded on an established securities market at the time of the disposition.

ADMINISTRATIVE MATTERS

PARTNERSHIP INFORMATION RETURNS AND AUDIT PROCEDURES

We intend to furnish to each unitholder, within 90 days after the close of each calendar year, certain tax information, including a substitute Schedule K-1, which sets forth each unitholder's share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will generally not be reviewed by counsel, we will use various accounting and reporting conventions, some of which have been mentioned in the previous discussion, to determine the unitholder's share of income, gain, loss and deduction. There is no assurance that any of those conventions will yield a result which conforms to the requirements of the Code, regulations or administrative interpretations of the IRS. We cannot assure prospective unitholders that the IRS will not successfully contend in court that such accounting and reporting conventions are impermissible. Any such challenge by the IRS could negatively affect the value of the units.

The federal income tax information returns filed by us may be audited by the IRS. Adjustments resulting from any such audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of the unitholder's own return. Any audit of a unitholder's return could result in adjustments of non-partnership as well as partnership items.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Code provides for one partner to be designated as the "Tax Matters Partner" for these purposes. Our partnership agreement appoints our general partner as our Tax Matters Partner.

The Tax Matters Partner has made and will make certain elections on our behalf and on behalf of the unitholders and can extend the statute of limitations for assessment of tax deficiencies against unitholders with respect to our items. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give such authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review (by which all the unitholders are bound) of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, such review may be sought by any unitholder having at least a 1% interest in our profits and by the unitholders having in the aggregate at least a 5% profits interest. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate. However, if we elect to be treated as a large partnership, a partner will not have the right to participate in settlement conferences with the IRS or to seek a refund.

A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of the consistency requirement may subject a unitholder to substantial penalties. However, if we elect to be treated as a large partnership, our partners would be required to treat all of our items in a manner consistent with our return.

NOMINEE REPORTING

Persons who hold an interest in us as a nominee for another person are required to furnish to us (a) the name, address and taxpayer identification number of the beneficial owner and the nominee; (b) whether the beneficial owner is (1) a person that is not a U.S. person, (2) a foreign government, an international organization or any wholly-owned agency or instrumentality of either of the foregoing, or (3) a tax-exempt entity; (c) the amount and description of units held, acquired or transferred for the beneficial owner; and (d) certain information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales. Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and certain information on units they acquire, hold or transfer for their own account. A penalty of $50 per failure (up to a maximum of $100,000 per calendar year) is imposed by the Code for failure to report such information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

REGISTRATION AS A TAX SHELTER

The Code requires that "tax shelters" be registered with the Secretary of the Treasury. The temporary Treasury Regulations interpreting the tax shelter registration provisions of the Code are extremely broad. It is arguable that we are not subject to the registration requirement on the basis that we will not constitute a tax shelter. However, our general partner, as our principal organizer, has registered us as a tax shelter with the Secretary of the Treasury in the absence of assurance that we will not be subject to tax shelter registration and in light of the substantial penalties which might be imposed if registration is required and not undertaken. ISSUANCE OF THE REGISTRATION NUMBER DOES NOT INDICATE THAT AN INVESTMENT IN THE PARTNERSHIP OR THE CLAIMED TAX BENEFITS HAVE BEEN REVIEWED, EXAMINED OR APPROVED BY THE IRS. The IRS has issued the following shelter registration number to us: 93084000079. We must furnish the registration number to the unitholders, and a unitholder who sells or otherwise transfers a unit in a subsequent transaction must furnish the registration number to the transferee. The penalty for failure of the transferor of a unit to furnish the registration number to the transferee is $100 for each such failure. The unitholders must disclose our tax shelter registration number on Form 8271 to be attached to the tax return on which any deduction, loss or other benefit generated by us is claimed or income of ours is included. A unitholder who fails to disclose the tax shelter registration number on his return, without reasonable cause for that failure, will be subject to a $250 penalty for each failure. Any penalties discussed herein are not deductible for federal income tax purposes.

ACCURACY-RELATED PENALTIES

An additional tax equal to 20% of the amount of any portion of an underpayment of tax which is attributable to one or more of certain listed causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Code. No penalty will be imposed, however, with respect to any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith with respect to that portion.

A substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000 ($10,000 for most corporations). The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return (1) with respect to which there is, or was, "substantial authority" or (2) as to which there is a reasonable basis and the pertinent facts of such position are disclosed on the return. Certain more stringent rules apply to "tax shelters," a term that in this context does not appear to include us. If any item of our income, gain, loss or deduction included in the distributive shares of unitholders might result in such an "understatement" of income for which no "substantial authority" exists, we must disclose the pertinent facts on its return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns to avoid liability for this penalty.

A substantial valuation misstatement exists if the value of any property (or the adjusted basis of any property) claimed on a tax return is 200% or more of the amount determined to be the correct amount of such valuation or adjusted basis. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for most corporations). If the valuation claimed on a return is 400% or more than the correct valuation, the penalty imposed increases to 40%.

STATE, LOCAL AND OTHER TAX CONSIDERATIONS

In addition to federal income taxes, unitholders will be subject to other taxes, such as state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on his investment in us. We will own property and conduct business in Texas and Louisiana; among other places. Of those, only Texas does not currently impose a personal income tax. A unitholder will be required to file state income tax returns and to pay state income taxes in some or all of the states in which we do business or own property and may be subject to penalties for failure to comply with those requirements. In certain states, tax losses may not produce a tax benefit in the year incurred (if, for example, we have no income from sources within that state) and also may not be available to offset income in subsequent taxable years. Some of the states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the state, generally does not relieve the non-resident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. See "--Disposition of Units--Entity-Level Collections." Based on current law and its estimate of our future operations, our general partner anticipates that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent states and localities, of his investment in us. Accordingly, each prospective unitholder should consult, and must depend upon, his own tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state and local, as well as U.S. federal, tax returns that may be required of such unitholder. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in us.

UNDERWRITING

Subject to the terms and conditions stated in the underwriting agreement dated the date hereof, each underwriter named below has severally agreed to purchase, and Leviathan has agreed to sell to such underwriter, the number of common units set forth opposite the name of such underwriter.

NAME	NUMBER OF COMMON UNITS
Salomon Smith Barney Inc.	
Goldman, Sachs & Co.	
PaineWebber Incorporated	
Dain Rauscher Wessels, a division of Dain Rauscher Incorporated	
First Union Capital Markets Corp.	
Total	4,000,000

The underwriting agreement provides that the obligations of the several underwriters to purchase the units included in this offering are subject to approval of certain legal matters by counsel and to certain other conditions. The underwriters are obligated to purchase all the common units (other than those covered by the over-allotment option described below) if they purchase any of the common units.

The underwriters, for whom Salomon Smith Barney Inc., Goldman, Sachs & Co., PaineWebber Incorporated, Dain Rauscher Wessels, a division of Dain Rauscher Incorporated and First Union Capital Markets Corp. are acting as representatives, propose to offer some of the common units directly to the public at the public offering price set forth on the cover page of this prospectus and some of the units to certain dealers at the public offering price less a concession not in excess of $ per common unit. The underwriters may allow, and such dealers may reallow, a concession not in excess of $ per common unit on sales to certain other dealers. If all of the common units are not sold at the initial offering price, the representatives may change the public offering price and the other selling terms.

Leviathan has granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to 600,000 additional common units at the public offering price less the underwriting discount. The underwriters may exercise such option solely for the purpose of covering over-allotments, if any, in connection with this offering. To the extent such option is exercised, each underwriter will be obligated, subject to certain conditions, to purchase a number of additional common units approximately proportionate to such underwriter's initial purchase commitment.

Leviathan, its general partner and EPEC Deepwater Gathering Company, a wholly owned subsidiary of El Paso, have agreed that, for a period of 180 days from the date of this prospectus, they will not, without the prior written consent of Salomon Smith Barney Inc., dispose of or hedge any common units of Leviathan or any securities convertible into or exchangeable for common units. The foregoing restriction shall not prohibit Leviathan's general partner or EPEC Deepwater from transferring common units owned by such person to a limited liability company of which such transferror is the sole member and pledging the member interests of such limited liability company to secure advances to El Paso Energy by Trinity River Associates, L.L.C., a limited liability company of which El Paso Energy is the managing member, as contemplated by an operating agreement between El Paso Energy and the other investors in Trinity River. Salomon Smith Barney Inc. in its sole discretion may release any of the securities subject to these lock-up agreements at any time without notice.

The common units are listed on the New York Stock Exchange under the symbol "LEV".

The following table shows the underwriting discounts and commissions to be paid to the underwriters by Leviathan in connection with this offering. These amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase additional common units.

	PAID BY LEVIATHAN	
	NO EXERCISE	FULL EXERCISE
Per unit	$	$
Total	$	$

In connection with the offering, Salomon Smith Barney Inc., on behalf of the underwriters, may purchase and sell the common units in the open market. These transactions may include over-allotment, syndicate covering transactions and stabilizing transactions. Over-allotment involves syndicate sales of common units in excess of the number of common units to be purchased by the underwriters in the offering, which creates a syndicate short position. Syndicate covering transactions involve purchases of the common units in the open market after the distribution has been completed in order to cover syndicate short positions. Stabilizing transactions consist of certain bids or purchases of common units made for the purpose of preventing or retarding a decline in the market price of the common units while the offering is in progress.

The underwriters also may impose a penalty bid. Penalty bids permit the underwriters to reclaim a selling concession from a syndicate member when Salomon Smith Barney Inc., in covering syndicate short positions or making stabilizing purchases, repurchases common units originally sold by that syndicate member.

Any of these activities may cause the price of the common units to be higher than the price that otherwise would exist in the open market in the absence of such transactions. These transactions may be effected on the New York Stock Exchange or in the over-the-counter market, or otherwise and, if commenced, may be discontinued at any time.

Leviathan estimates that its portion of the total expenses of this offering will be $8.4 million.

The representatives have performed certain investment banking and advisory services for Leviathan from time to time for which they have received customary fees and expenses. The representatives may, from time to time, engage in transactions with and perform services for Leviathan in the ordinary course of their business.

Leviathan has agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act of 1933, or to contribute to payments the underwriters may be required to make in respect of any of those liabilities.

LEGAL MATTERS

Certain legal matters with respect to the legality of the common units being offered and certain tax matters will be passed upon for us by Akin, Gump, Strauss, Hauer & Feld, L.L.P., Houston, Texas. Certain legal matters with respect to the legality of the common units being offered will be passed upon for the underwriters by Andrews & Kurth L.L.P., Houston, Texas.

EXPERTS

The consolidated financial statements of Leviathan Gas Pipeline Partners, L.P. and its subsidiaries as of December 31, 1998 and 1997 and for each of the three years in the period ended December 31, 1998 included in this Registration Statement have been so included in reliance on the report of PricewaterhouseCoopers LLP, independent accountants, given on the authority of said firm as experts in auditing and accounting.

The financial statements of Viosca Knoll Gathering Company as of December 31, 1998 and 1997 and for each of the three years in the period ended December 31, 1998 included in this Registration Statement have been so included in reliance on the report of PricewaterhouseCoopers LLP, independent accountants, given on the authority of said firm as experts in auditing and accounting.

The statements of financial position of High Island Offshore System, L.L.C. as of December 31, 1998 and 1997 and the related statements of income, members' equity, and cash flows for each of the three years in the period ended December 31, 1998 included in this Registration Statement have been so included in reliance on the report of Deloitte & Touche LLP, independent auditors, given upon the authority of said firm as experts in auditing and accounting.

The financial statements of Poseidon Oil Pipeline Company, L.L.C. as of December 31, 1998 and 1997 and for the years ended December 31, 1998 and 1997 and for the period from inception (February 14, 1996) through December 31, 1996 included in this Registration Statement have been so included in reliance on the report of Arthur Andersen LLP, independent public accountants, given on the authority of said firm as experts in auditing and accounting.

The consolidated financial statements of Neptune Pipeline Company, L.L.C. as of December 31, 1998 and 1997 and for the years then ended included in this Registration Statement have been so included in reliance on the report of PricewaterhouseCoopers LLP, independent accountants, given on the authority of said firm as experts in auditing and accounting.

The balance sheet of Leviathan Finance Corporation as of April 30, 1999 included in this Registration Statement has been so included in reliance on the report of PricewaterhouseCoopers LLP, independent accountants, given on the authority of said firm as experts in auditing and accounting.

The balance sheet of Leviathan Gas Pipeline Company as of December 31, 1998 included in this Registration Statement has been so included in reliance on the report of PricewaterhouseCoopers LLP, independent accountants, given on the authority of said firm as experts in auditing and accounting.

The information derived from the report of Netherland, Sewell & Associates, Inc., independent petroleum engineers, with respect to estimated oil and natural gas reserves of Leviathan Gas Pipeline Partners, L.P. and its subsidiaries included in this Registration Statement have been so included in reliance upon the authority of said firm as experts with respect to such matters contained in their report.

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GLOSSARY

The following abbreviations, acronyms or defined terms used in certain financial statements are defined below:

Bcf........................	Billion cubic feet
East Breaks................	East Breaks Gathering Company, L.L.C., a Delaware limited liability company and wholly owned subsidiary of Western Gulf
El Paso Energy.............	El Paso Energy Corporation, a Delaware corporation and the indirect parent of the General Partner
EPFS.......................	El Paso Field Services Company, a Delaware corporation and a wholly owned subsidiary of El Paso Energy
Equity Investees...........	Collectively refers to Stingray, West Cameron Dehy, POPCO, Manta Ray Offshore, Nautilus, HIOS, UTOS and prior to June 1, 1999, Viosca Knoll
General Partner............	Leviathan Gas Pipeline Company, a Delaware corporation and wholly owned indirect subsidiary of El Paso Energy
Green Canyon...............	Green Canyon Pipe Line Company, L.L.C., a Delaware limited liability company and wholly owned subsidiary of Leviathan
Gulf.......................	Gulf of Mexico
HIOS.......................	High Island Offshore System, L.L.C., a Delaware limited liability company and wholly owned subsidiary of Western Gulf
Leviathan..................	Leviathan Gas Pipeline Partners, L.P., a publicly held Delaware master limited partnership, and its subsidiaries, unless the context otherwise requires
Manta Ray Offshore.........	Manta Ray Offshore Gathering Company, L.L.C., a Delaware limited liability company and owned by Neptune and Ocean Breeze
Mcf........................	Thousand cubic feet
MMcf.......................	Million cubic feet
MMbtu......................	Million British thermal units
Nautilus...................	Nautilus Pipeline Company, L.L.C., a Delaware limited liability company and owned by Neptune and Ocean Breeze
Neptune....................	Neptune Pipeline Company, L.L.C., a Delaware limited liability company in which Leviathan owns a 25.67% member interest
Ocean Breeze...............	Ocean Breeze Pipeline Company, L.L.C., a Delaware limited liability company in which Leviathan owns a 25.67% member interest
NYMEX......................	New York Mercantile Exchange
POPCO......................	Poseidon Oil Pipeline Company, L.L.C., a Delaware limited liability company in which Leviathan owns a 36% member interest
Stingray...................	Stingray Pipeline Company, L.L.C., a Delaware limited liability company in which Leviathan owns a 50% member interest
Tarpon.....................	Tarpon Transmission Company, a Texas corporation and wholly owned subsidiary of Leviathan
UTOS.......................	U-T Offshore System, a Delaware partnership in which Leviathan collectively owns a 66.67% member interest
West Cameron Dehy..........	West Cameron Dehydration Company, L.L.C., a Delaware limited liability company in which Leviathan owns a 50% member interest
Western Gulf...............	Western Gulf Holdings, L.L.C., a Delaware limited liability company in which Leviathan collectively owns a 60% member interest
Viosca Knoll...............	Viosca Knoll Gathering Company, a Delaware general partnership in which Leviathan owns a 99% partnership interest

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The unaudited pro forma condensed consolidated financial statements as of and for the six months ended June 30, 1999 and for the year ended December 31, 1998 have been prepared based on the historical consolidated balance sheet and statements of operations of Leviathan Gas Pipeline Partners, L.P. and its subsidiaries ("Leviathan"). The historical balance sheet and statements of operations were adjusted to give effect to the transactions identified below (the "Transactions"). The historical balance sheet was adjusted to give effect to the Transactions described in (4) below as if they had occurred on June 30, 1999. The effect of the Transactions described in (1), (2) and (3) are included in Leviathan's historical results as of June 30, 1999. The historical statement of operations for the six months ended June 30, 1999 and for the year ended December 31, 1998 were adjusted to give effect to the Transactions as if the Transactions had occurred on January 1, 1998.

Leviathan, a publicly held Delaware master limited partnership, is primarily engaged in the gathering and transportation and production of natural gas and crude oil in the Gulf of Mexico (the "Gulf"). Through its subsidiaries and joint ventures, Leviathan owns interests in certain significant assets, including (i) nine (eight existing and one under construction) natural gas pipelines, (ii) two (one existing and one under construction) crude oil pipeline systems, (iii) six strategically-located multi-purpose platforms, (iv) a dehydration facility, (v) four producing oil and natural gas properties and (vi) a 100% working interest in a non-producing oil and natural gas unit comprised of Ewing Bank Blocks 958, 959, 1002 and 1003.

The unaudited pro forma financial information gives effect to the following Transactions:

(1) In May 1999, Leviathan sold $175 million of Senior Subordinated Notes due May 2009 (the "Subordinated Notes"). Proceeds from the Subordinated Notes were used (a) to fund the cash portion of the acquisition of the additional interest in Viosca Knoll Gathering Company ("Viosca Knoll") as described in (2) below, (b) to repay outstanding principal under Viosca Knoll's credit facility discussed in (2) below, (c) to reduce the balance outstanding on Leviathan's $375 million credit facility, as amended and restated, (the "Credit Facility") and (d) to pay fees and expenses incurred in connection with the sale of the Subordinated Notes and the Credit Facility.

(2) On January 21, 1999, Leviathan entered into a Contribution Agreement with El Paso Field Services Company ("El Paso"), to acquire all of El Paso's interest in Viosca Knoll, other than a 1% interest in profits and capital in Viosca Knoll. At the time the Contribution Agreement was executed, Leviathan and El Paso each beneficially owned a 50% interest in Viosca Knoll. On June 1, 1999 (the "Closing Date"), Leviathan and El Paso consummated the Viosca Knoll transactions. In connection therewith, (i) a subsidiary of El Paso contributed to Viosca Knoll $33,350,000 (the "Capital Contribution"), which amount was equal to 50% of the amount then outstanding under Viosca Knoll's credit facility, (ii) a subsidiary of Leviathan acquired a 49% interest in Viosca Knoll from a subsidiary of El Paso in exchange for the cash payment of $19,930,750 and the issuance of 2,661,870 Common Units, and (iii) as required by Leviathan's Amended and Restated Agreement of Limited Partnership, Leviathan Gas Pipeline Company, Leviathan's general partner, contributed $603,962 to Leviathan in order to maintain its 1% capital account balance. Concurrently with the closing of the Viosca Knoll transactions, Leviathan also contributed $33,350,000 to Viosca Knoll. These funds and the Capital Contribution were used to repay and terminate Viosca Knoll's credit facility. Furthermore, effective on the Closing Date, Leviathan began consolidating the accounts and operations of Viosca Knoll.

(3) On June 30, 1999, Leviathan acquired (i) all of the outstanding stock of Natoco, Inc., which owns a 20% member interest in Western Gulf Holdings, L.L.C. ("Western Gulf"), which in turn owns 100% of High Island Offshore System, L.L.C. ("HIOS") and East Breaks Gathering Company, L.L.C. ("East Breaks"), and Naloco, Inc. (Del.), which owns a 33 1/3% interest in U-T Offshore System ("UTOS") and (ii) various ownership interests in certain lateral pipelines located in the Gulf from

Natural Gas Pipeline Company of America ("NGPL"), a subsidiary of KN Energy, Inc. (collectively the "HIOS/UTOS Transactions"). The East Breaks system is currently under construction and will initially consist of 85 miles of pipeline, with a design capacity of over 400 million cubic feet of natural gas per day, and related facilities connecting the Diana/Hoover prospects developed by Exxon Company USA and BP Amoco plc in Alaminos Canyon Block 25 in the Gulf, with the HIOS system. The new pipeline and related facilities are anticipated to be in service in late 2000. The UTOS system transports natural gas from the terminus of the HIOS system to the Johnson Bayou facility in southern Louisiana with access to one intrastate and four interstate pipelines. Additionally, Stingray Pipeline Company, L.L.C., which is owned 50% by each of Leviathan and NGPL, purchased from NGPL certain offshore laterals that connect to the Stingray pipeline for approximately $5 million. After a transition period that could end as soon as October 1, 1999, but not later than January 1, 2000, Leviathan will assume NGPL's role as operator of the Stingray pipeline, the Stingray Onshore Separation Facility, the West Cameron Dehydration Facility and certain other lateral pipelines (the "Related Facilities"). Leviathan financed this acquisition with funds from the Credit Facility.

(4) The issuance of 4,000,000 common units of Leviathan (the "Offering") and the required capital contribution by Leviathan's general partner in order to maintain its 1% capital account balance. Proceeds from the Offering and the general partner capital contribution will be used to pay fees and expenses incurred in connection with the Offering and to reduce the principal balance outstanding under the Credit Facility.

The unaudited pro forma condensed consolidated financial statements are not necessarily indicative of Leviathan's consolidated financial condition or results of operations that might have occurred had the Transactions been completed at the beginning of the period or as of the dates specified, and do not purport to indicate Leviathan's consolidated financial condition or results of operations for any future period or at any future date. The unaudited pro forma condensed consolidated statements should be read in the context of the related historical consolidated financial statements and notes thereto appearing elsewhere in this prospectus.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED BALANCE SHEET
JUNE 30, 1999
(IN THOUSANDS)

	HISTORICAL LEVIATHAN	PRO FORMA FINANCING ADJUSTMENTS	PRO FORMA
ASSETS			
Current assets:			
Cash and cash equivalents	$ 3,301	$100,000(a) (8,400)(a) 925(b) (92,525)(c)	$ 3,301
Accounts receivable	9,180	--	9,180
Other current assets	344	--	344
Total current assets	12,825	--	12,825
Property and equipment, net	381,210		381,210
Equity investments	219,732		219,732
Other noncurrent assets	12,146		12,146
Total assets	$625,913	$ --	$625,913
LIABILITIES AND PARTNERS' CAPITAL			
Current liabilities:			
Accounts payable and accrued liabilities	$ 12,475	$ --	$ 12,475
Total current liabilities	12,475	--	12,475
Notes payable	306,500	(92,525)(c)	213,975
Long-term debt	175,000		175,000
Other noncurrent liabilities	12,151	--	12,151
Total liabilities	506,126	(92,525)	413,601
Minorities interests	(249)	--	(249)
Partners' capital:			
Preference unitholders	6,923	--	6,923
Common unitholders	132,345	100,000(a) (8,400)(a)	223,945
General partner	(19,232)	925(b)	(18,307)
	120,036	92,525	212,561
Total liabilities and partners' capital	$625,913	$ --	$625,913

The accompanying notes are an integral part of this financial statement.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS
SIX MONTHS ENDED JUNE 30, 1999
(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)

	HISTORICAL LEVIATHAN	PRO FORMA FINANCING ADJUSTMENTS	HISTORICAL VIOSCA KNOLL	PRO FORMA ACQUISITION ADJUSTMENTS		PRO FORMA
				VIOSCA KNOLL	HIOS/UTOS	
Revenue:						
Oil and natural gas sales........	$ 15,100	$ --	$ 49	$ (8)(f)	$ --	$ 15,141
Gathering, transportation and platform services..............	10,798	--	14,743	(2,446)(f)	645(l)	23,740
Equity in earnings...............	19,953	--	--	(3,860)(g)	1,040(m) 166(m) 105(n)	17,404
	45,851	--	14,792	(6,314)	1,956	56,285
Costs and expenses:						
Operating expenses...............	5,025	--	1,129	(268)(f)	175(l)	6,061
Depreciation, depletion and amortization...................	13,727	--	2,191	637(h) (438)(f)	198(l)	16,315
General and administrative expenses and management fee....	5,909	--	71	(8)(f)	--	5,972
	24,661	--	3,391	(77)	373	28,348
Operating income...................	21,190	--	11,401	(6,237)	1,583	27,937
Interest and other income..........	268	--	33	(2)(f)	500(o)	799
Interest and other financing costs............................	(13,868)	13,868(a) (9,078)(b) (294)(b) (7,964)(c)	(1,973)	1,973(i)	--	(17,336)
Minority interests in (income) loss.............................	(80)	35(d)	--	17(f) (167)(j)	(21)(p)	(216)
Income before income taxes.........	7,510	(3,433)	9,461	(4,416)	2,062	11,184
Income tax benefit.................	177	--	--	--	--	177
Net income.........................	$ 7,687	$ (3,433)	$ 9,461	$(4,416)	$2,062	$ 11,361
Weighted average number units outstanding......................	24,808	4,000(e)		2,221(k)		31,029
Basic and diluted net income per unit.............................	$ 0.25					$ 0.30

The accompanying notes are an integral part of this financial statement.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 1998
(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)

	HISTORICAL LEVIATHAN	PRO FORMA FINANCING ADJUSTMENTS	HISTORICAL VIOSCA KNOLL	PRO FORMA ACQUISITION ADJUSTMENTS		PRO FORMA
				VIOSCA KNOLL	HIOS/UTOS	
Revenue:						
Oil and natural gas sales	$ 31,411	$ --	$ 528	$ --	$ --	$ 31,939
Gathering, transportation and platform services	17,320	--	28,806	--	1,289(l)	47,415
Equity in earnings	26,724	--	--	(9,113)(g)	2,679(m) 548(m) 210(n)	21,048
	75,455	--	29,334	(9,113)	4,726	100,402
Costs and expenses:						
Operating expenses	11,369	--	2,877	--	349(l)	14,595
Depreciation, depletion and amortization	29,267	--	3,860	1,274(h)	396(l)	34,797
Impairment, abandonment and other	(1,131)	--	--	--	--	(1,131)
General and administrative expenses and management fee	16,189	--	154	--	--	16,343
	55,694	--	6,891	1,274	745	64,604
Operating income	19,761	--	22,443	(10,387)	3,981	35,798
Interest and other income	771	--	50	--	1,000(o)	1,821
Interest and other financing costs	(20,242)	20,242(a) (18,156)(b) (589)(b) (10,467)(c)	(4,267)	4,267(i)	--	(29,212)
Minority interests in (income) loss	(15)	91(d)	--	(347)(j)	(50)(p)	(321)
Income before income taxes	275	(8,879)	18,226	(6,467)	4,931	8,086
Income tax benefit	471	--	--	--	--	471
Net income	$ 746	$ (8,879)	$18,226	$ (6,467)	$4,931	$ 8,557
Weighted average number units outstanding	24,367	4,000(e)		2,662(k)		31,029
Basic and diluted net income per unit	$ 0.02					$ 0.22

The accompanying notes are an integral part of this financial statement.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO UNAUDITED PRO FORMA CONDENSED
CONSOLIDATED FINANCIAL STATEMENTS

The unaudited pro forma condensed consolidated financial statements have been prepared to reflect the Transactions described on pages F-4 and F-5 and the application of the adjustments to the historical amounts as described below:

BALANCE SHEET

(a) To record the proceeds from the Offering ($100.0 million) and the payment of fees and expenses related to the Offering ($8.4 million).

(b) To record the capital contribution (1.0%) by Leviathan's general partner described in Transaction (4).

(c) To reduce the principal balance outstanding under the Credit Facility using the net proceeds from the Offering and the general partner's capital contribution calculated as follows (in thousands):

Proceeds from the Offering	$100,000
Fees and expenses related to the Offering	(8,400)
General partner capital contribution	925
Net proceeds used to reduce Credit Facility	$ 92,525

STATEMENT OF OPERATIONS

(a) To reverse Leviathan's historical interest expense.

(b) To record (i) interest expense on the Subordinated Notes at a rate of 10 3/8% per annum and (ii) amortization of debt issue costs related to the Subordinated Notes ($5.9 million) over ten years.

(c) To record interest expense and amortization of debt issue costs related to the amended and restated Credit Facility calculated as follows (in thousands):

SIX MONTHS ENDED JUNE 30, 1999	1ST QUARTER	2ND QUARTER	TOTAL
Credit Facility interest expense:			
Outstanding balance at beginning of quarter	$184,554	$201,554	
Quarterly borrowings	17,000	12,421	
Outstanding balance at end of quarter	$201,554	$213,975	
Average outstanding balance	$193,054	$207,764	
Assumed average interest rate	7.5%	7.5%	
Assumed quarterly interest expense	$ 3,620	$ 3,896	$ 7,516
Less capitalized interest			(755)
Commitment fees and other			82
Amortization of debt issue costs			1,121 see (x) below
Adjusted interest expense			$ 7,964
Credit Facility debt issue costs:			
Balance of debt issue costs as of January 1, 1998	$ 3,749		
Amendment and restatement fees	2,975		
	6,724		
Life of Credit Facility	3 years		
Debt issue cost amortization for six months	$ 1,121(x)		

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO UNAUDITED PRO FORMA CONDENSED
CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

YEAR ENDED DECEMBER 31, 1998	1ST QUARTER	2ND QUARTER	3RD QUARTER	4TH QUARTER	TOTAL
Credit Facility interest expense:					
Outstanding balance as of January 1, 1998..........	$ 238,000				
Net reduction of Credit Facility(1).............	(153,446)				
Outstanding balance at beginning of quarter.....	84,554	$ 97,554	$116,554	$137,554	
Quarterly borrowings........	13,000	19,000	21,000	47,000	
Outstanding balance at end of quarter...............	$ 97,554	$116,554	$137,554	$184,554	
Average outstanding balance..................	$ 91,054	$107,054	$127,054	$161,054	
Assumed average interest rate.....................	7.5%	7.5%	7.5%	7.5%	
Assumed quarterly interest expense..................	$ 1,708	$ 2,007	$ 2,382	$ 3,020	$ 9,117
Less capitalized interest......................................					(1,066)
Commitment fees......................................					175
Amortization of debt issue costs......................................					2,241 see (y) below
Adjusted interest expense......................................					$10,467
Credit Facility debt issue costs:					
Balance of debt issue costs as of January 1, 1998....	$ 3,749				
Amendment and restatement fees.....................	2,975				
	6,724				
Life of Credit Facility.....	3 years				
Annual debt issue cost amortization............	$ 2,241(y)				

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(1) The net reduction of the Credit Facility on January 1, 1998 is calculated as follows (in thousands):

Proceeds from the Subordinated Notes.......................	$175,000
Proceeds from the Offering.................................	100,000
Capital contribution by the general partner.................	925
Fees and expenses related to sale of the Subordinated Notes..	(5,885)
Fees and expenses related to the Offering..................	(8,400)
Cash portion of the acquisition of the additional Viosca Knoll interest..	(20,741)
Repayment and cancellation of Viosca Knoll's credit facility..	(33,350)
Fees and expenses associated with the amended and restated Credit Facility..	(2,975)
Consummate the HIOS/UTOS Transactions......................	(51,128)
Net reduction of the Credit Facility.....................	$153,446

(d) To record the minority interest in expense for the approximate 1.0% minority interest ownership in certain of Leviathan's subsidiaries.

NOTES TO UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

(e) To adjust weighted average units outstanding for the 4,000,000 common units issued in connection with the Offering.

(f) To reverse the June 1999 results of operations of Viosca Knoll which are included in Leviathan's historical results of operations as Leviathan began consolidating Viosca Knoll on June 1, 1999.

(g) To reverse Leviathan's historical equity in earnings of Viosca Knoll.

(h) To record depreciation expense associated with the allocation of the excess purchase price to Viosca Knoll's property and equipment. Such equipment will be depreciated on a straight-line basis over the remaining useful lives of the assets which approximate 25 years.

(i) To reverse interest expense related to Viosca Knoll's credit facility which was repaid with the proceeds from the Capital Contribution and the Subordinated Notes.

(j) To adjust minority interest in income for the approximate 1.0% minority interest ownership in certain of Leviathan's subsidiaries and the 1.0% minority interest ownership in Viosca Knoll.

(k) To adjust weighted average units outstanding for the 2,661,870 common units issued at the Closing Date.

(l) To record transportation revenue, operating expenses and depreciation related to certain pipeline laterals acquired. The pipeline laterals will be depreciated on a straight-line basis over their estimated remaining useful lives of 5 years.

(m) To record Leviathan's additional equity in earnings of HIOS and UTOS calculated as follows (in thousands). Since Leviathan's control of its investments in HIOS and UTOS is expected to be temporary, Leviathan will continue to use the equity method to account for these investments.

	SIX MONTHS ENDED JUNE 30, 1999		YEAR ENDED DECEMBER 31, 1998	
	HIOS	UTOS	HIOS	UTOS
Net investee earnings	$8,498	$798	$19,983	$2,247
Additional ownership interest	20%	33.3%	20%	33.3%
	1,700	266	3,997	748
Adjustment:				
Depreciation(1)	(659)	(100)	(1,318)	(200)
Equity in earnings	$1,041	$166	$ 2,679	$ 548

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(1) Results from purchase price adjustments made in accordance with Accounting Principles Board Opinion No. 16, "Business Combinations." The purchase price of the HIOS/UTOS Transactions exceeded the fair value of net assets acquired by approximately $45.5 million. The excess cost has been preliminarily assigned to property and equipment and will be amortized on a straight-line basis over an estimated remaining life of 30 years.

(n) To record additional equity in earnings of Stingray calculated as 50% of the net earnings related to certain laterals acquired by Stingray in connection with the HIOS/UTOS Transactions.

(o) To record the management fee related to Leviathan's operation of the Related Facilities.

(p) To adjust minority interest in income for the approximate 1.0% minority interest ownership in certain of Leviathan's subsidiaries.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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

	QUARTER ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	1999	1998	1999	1998
Revenue	$23,972	$18,373	$ 45,851	$36,087
Costs and expenses				
Operating expenses	2,431	2,708	5,025	5,546
Depreciation, depletion and amortization	7,009	6,978	13,727	14,845
General and administrative expenses and management fee	2,779	2,554	5,909	7,503
	12,219	12,240	24,661	27,894
Operating income	11,753	6,133	21,190	8,193
Interest income and other	165	73	268	157
Interest and other financing costs	(7,766)	(4,707)	(13,868)	(8,429)
Minority interest in income	(43)	(16)	(80)	(3)
Income (loss) before income taxes	4,109	1,483	7,510	(82)
Income tax benefit	79	27	177	168
Net income	$ 4,188	$ 1,510	$ 7,687	$ 86
Weighted average number of units outstanding	25,244	24,367	24,808	24,367
Basic and diluted net income per unit	$ 0.13	$ 0.05	$ 0.25	$ 0.00

The accompanying Notes are an integral part of these Condensed Consolidated Financial Statements.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS)

ASSETS

	JUNE 30, 1999 (UNAUDITED)	DECEMBER 31, 1998
Current assets		
Cash and cash equivalents	$ 3,301	$ 3,108
Accounts receivable	9,180	8,588
Other current assets	344	247
Total current assets	12,825	11,943
Equity investments (Notes 2 and 3)	219,732	186,079
Property and equipment, net (Notes 2 and 4)	381,210	241,992
Other noncurrent assets	12,146	2,712
Total assets	$625,913	$442,726
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable and accrued liabilities	$ 12,475	$ 11,167
Notes payable (Note 6)	--	338,000
Total current liabilities	12,475	349,167
Notes payable (Note 6)	306,500	--
Long-term debt (Note 6)	175,000	--
Other noncurrent liabilities	12,151	11,661
Total liabilities	506,126	360,828
Commitments and contingencies		
Minority interest	(249)	(998)
Partners' capital (Note 2)	120,036	82,896
Total liabilities and partners' capital	$625,913	$442,726

The accompanying Notes are an integral part of these Condensed Consolidated Financial Statements.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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

	SIX MONTHS ENDED JUNE 30, 1999	SIX MONTHS ENDED JUNE 30, 1998
Cash flows from operating activities		
Net income	$ 7,687	$ 86
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	13,727	14,845
Distributions from equity investees	24,108	13,298
Equity in earnings	(19,953)	(12,571)
Other noncash items	721	509
Working capital changes, net of effects of acquisitions	(2,650)	(3,283)
Net cash provided by operating activities	23,640	12,884
Cash flows from investing activities		
Additions to pipelines, platforms and facilities	(14,260)	(12,283)
Investments in equity investees	(4,393)	(4,543)
Acquisition of additional interests in equity investees, net of cash received	(51,128)	--
Net cash flow impact of acquisition of Viosca Knoll	(19,856)	--
Development of oil and natural gas properties	(3,181)	(2,540)
Net cash used in investing activities	(92,818)	(19,366)
Cash flows from financing activities		
Proceeds from notes payable	95,500	50,000
Long-term debt issuance	175,000	--
Repayments of notes payable	(160,350)	(18,000)
Debt issuance costs	(10,126)	--
Distributions to partners	(31,256)	(30,806)
General Partner's contribution	603	--
Net cash provided by financing activities	69,371	1,194
Increase (decrease) in cash and cash equivalents	193	(5,288)
Cash and cash equivalents		
Beginning of period	3,108	6,430
End of period	$ 3,301	$ 1,142

Non-cash Investing Activities: See Note 2 for discussion.

The accompanying Notes are an integral part of these Condensed Consolidated Financial Statements.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
(IN THOUSANDS)

	PREFERENCE UNITS	PREFERENCE UNITHOLDERS	COMMON UNITS	COMMON UNITHOLDERS	GENERAL PARTNER(A)	TOTAL
Partners' capital at December 31, 1998	1,017	$7,351	23,350	$ 90,972	$(15,427)	$ 82,896
Net income for the six months ended June 30, 1999 (unaudited)	--	131	--	6,098	1,458	7,687
Issuance of Common Units for acquisition of additional interest in Viosca Knoll (unaudited)	--	--	2,662	59,792	--	59,792
General Partner contribution related to issuance of Common Units (unaudited)	--	--	--	--	603	603
Cash distributions (unaudited)	--	(559)	--	(24,517)	(5,866)	(30,942)
Partners' capital at June 30, 1999 (unaudited)	1,017	$6,923	26,012	$132,345	$(19,232)(b)	$120,036

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(a) Leviathan Gas Pipeline Company owns a 1% general partner interest in Leviathan.

(b) Pursuant to the terms of Leviathan's partnership agreement, no partner shall have any obligation to restore any negative balance in its capital account upon liquidation of Leviathan. Therefore, any net gains from the dissolution of Leviathan's assets would be allocated first to any then-outstanding deficit capital account balance before any of the remaining net proceeds would be distributed to the partners in accordance with their ownership percentages.

The accompanying Notes are an integral part of these Condensed Consolidated Financial Statements.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 -- ORGANIZATION AND BASIS OF PRESENTATION:

Leviathan is a provider of integrated energy services, including natural gas and oil gathering, transportation, midstream and other related services in the Gulf. Through its subsidiaries and joint ventures, Leviathan owns interests in significant assets, including (i) nine (eight existing and one under construction) natural gas pipelines (the "Gas Pipelines"), (ii) two (one existing and one under construction) oil pipeline systems, (iii) six strategically-located multi-purpose platforms, (iv) production handling and dehydration facilities, (v) four producing oil and natural gas properties and (vi) a non-producing oil and natural gas property, the Ewing Bank 958 Unit, comprised of Ewing Bank Blocks 958, 959, 1002 and 1003, formerly referred to as the Sunday Silence property. The General Partner performs all management and operational functions for Leviathan and its subsidiaries.

As of June 30, 1999, Leviathan had 26,011,858 Common Units and 1,016,906 Preference Units outstanding. The public owns limited partner interests representing an effective 65.5% interest in Leviathan, comprised of 1,016,906 Preference Units and 17,058,094 Common Units. El Paso Energy, through its subsidiaries, owns an effective 34.5% economic interest in Leviathan, comprised of a 32.5% limited partner interest in the form of 8,953,764 Common Units, its 1% general partner interest in Leviathan and its approximate 1% nonmanaging member interest in certain subsidiaries of Leviathan.

The 1998 Annual Report on Form 10-K for Leviathan includes a summary of significant accounting policies and other disclosures and should be read in conjunction with this Quarterly Report on Form 10-Q. The condensed consolidated financial statements at June 30, 1999, and for the quarters and six months ended June 30, 1999 and 1998 are unaudited. The condensed consolidated balance sheet at December 31, 1998 is derived from audited consolidated financial statements at that date. These financial statements do not include all disclosures required by generally accepted accounting principles, but have been prepared pursuant to the rules and regulations of the United States Securities and Exchange Commission. In the opinion of management, all material adjustments necessary to present fairly the consolidated financial position and results of operations for such periods have been included. All such adjustments are of a normal recurring nature. Results of operations for any interim period are not necessarily indicative of the results of operations for the entire year due to the seasonal nature of Leviathan's businesses.

NOTE 2 -- ACQUISITIONS:

Viosca Knoll

In January 1999, Leviathan entered into a Contribution Agreement with EPFS to acquire all of EPFS's interest in Viosca Knoll other than a 1% interest in profits and capital of Viosca Knoll. At the time the Contribution Agreement was executed, Leviathan and EPFS each beneficially owned a 50% interest in Viosca Knoll, which was formed in 1994 to construct, own and operate an unregulated gathering system designed to serve the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf. The Viosca Knoll system is comprised of (i) an approximately 94 mile, 20-inch diameter pipeline from a platform in Main Pass Block 252 owned by Shell Offshore, Inc. to a pipeline owned by Tennessee Gas Pipeline Company at South Pass Block 55 and (ii) a six mile 16-inch diameter pipeline from an interconnection with the 20-inch diameter pipeline at Leviathan's Viosca Knoll Block 817 platform to a pipeline owned by Southern Natural Gas Company at Main Pass Block 289.

Leviathan and EPFS closed the Viosca Knoll acquisition on June 1, 1999. In connection therewith, (i) EPFS contributed to Viosca Knoll $33.4 million, which amount was equal to 50% of the amount then outstanding under Viosca Knoll's credit facility, (ii) a subsidiary of EPFS transferred a 49% interest in Viosca Knoll to Leviathan, (iii) Leviathan paid to a subsidiary of EPFS $19.9 million and issued to that subsidiary 2,661,870 Common Units, (iv) Leviathan paid other closing costs of $0.8 million and (v) as required by Leviathan's Amended and Restated Agreement of Limited Partnership, the General Partner contributed $0.6 million to Leviathan in order to maintain its 1% capital account balance. In addition, during the six months commencing on June 1, 2000, Leviathan has an option to acquire the remaining 1% interest in profits and capital of Viosca Knoll for a cash payment equal to the sum of $1.6 million plus the amount of additional distributions (paid, payable or in arrears) which would have been paid, accrued or been in arrears had Leviathan acquired the remaining 1% of Viosca Knoll on June 1, 1999, by issuing additional Common Units in lieu of a cash payment of $1.7 million. Leviathan used the equity method of accounting for its 50% interest in Viosca Knoll through May 31, 1999. As a result of its acquisition of an additional 49% interest in Viosca Knoll, Leviathan began consolidating Viosca Knoll as of June 1, 1999. The acquisition of Viosca Knoll was accounted for as a purchase and the purchase price was assigned to the assets and liabilities acquired based upon the estimated fair value of those assets and liabilities as of the acquisition date. The fair value of allocations are preliminary and may be revised after the completion of an independent appraisal.

	(IN THOUSANDS)
Fair value of assets acquired	$ 83,061
Cash acquired	434
Fair value of liabilities assumed	(2,962)
Total purchase price	80,533
Issuance of common units	(59,792)
Net cash paid	$ 20,741

The following selected unaudited pro forma information represents Leviathan's consolidated results of operations on a pro forma basis for the six month periods ended June 30, 1999 and 1998, assuming the Viosca Knoll acquisition had occurred on January 1, 1998:

	SIX MONTHS ENDED JUNE 30, 1999	1998
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)	
Revenue	$54,330	$46,021
Operating income	$26,355	$14,334
Net income	$ 9,650	$ 3,005
Basic and diluted net income per unit	$ 0.29	$ 0.09

HIOS/UTOS

On June 30, 1999, subsidiaries of Leviathan acquired from Natural Gas Pipeline Company of America ("NGPL"), a subsidiary of KN Energy, Inc., for total consideration of approximately $51 million, net of cash received, (i) all of the outstanding stock of two of NGPL's wholly-owned subsidiaries, Natoco, Inc. ("Natoco"), which owns a 20% member interest in Western Gulf, which in turn owns 100% of each of HIOS and East Breaks, and Naloco, Inc. (Del.) ("Naloco"), which owns a 33.33% interest in UTOS, and (ii) NGPL's ownership interest in certain lateral pipelines located in the Gulf. In addition, Leviathan will assume NGPL's role as operator of Stingray, the Stingray Offshore Separation Facility and West Cameron Dehydration Facility. Leviathan financed this acquisition with funds borrowed under its $375 million revolving credit facility discussed in Note 6. The purchase price exceeded the fair market value of net assets acquired by approximately $48 million. This excess cost has been preliminary assigned to property and equipment and is to be amortized on a straight line basis over 30 years. After giving effect to the acquisition, Leviathan owns a 60% interest in Western Gulf, and thus an effective 60% interest in each of HIOS and East Breaks and a 66.67% interest in UTOS. Since Leviathan's control is expected to be temporary, these investments will continue to be accounted for under the equity method of accounting.

Western Gulf was formed in December 1998 by Leviathan, NGPL and ANR Pipeline Company ("ANR") as a holding company for HIOS and East Breaks. HIOS consists of approximately 204 miles of pipeline comprised of three supply laterals, the West, Central and East Laterals, that connect to a 42-inch diameter mainline. The HIOS system was placed in service in 1977 and is used to gather and transport natural gas produced from fields located in the Galveston, Garden Banks, High Island, West Cameron and East Breaks areas of the Gulf to a junction platform owned by HIOS located in West Cameron Block 167. The total capacity of the HIOS system is approximately 1.8 Bcf of natural gas per day. ANR operates the HIOS system. The East Breaks system is currently under construction, with a design capacity of over 400 Mcf of natural gas per day, and will initially consist of 85 miles of an 18 to 20-inch pipeline and related facilities connecting the Diana/Hoover prospects developed by Exxon Company USA ("Exxon") and BP Amoco plc ("BP Amoco") in Alaminos Canyon Block 25, with the HIOS system. The majority of the construction of the East Breaks system will occur in 1999 and the system is anticipated to be in service by mid-2000 at an estimated cost of approximately $90 million.

Prior to June 30, 1999, UTOS was owned equally by Leviathan, NGPL and ANR. The UTOS system was placed in service in 1978 and consists of approximately 30 miles of 42-inch diameter pipeline extending from a point of interconnection with HIOS at West Cameron Block 167 to the Johnson Bayou processing facility in southern Louisiana. The UTOS system transports natural gas from the terminus of the HIOS system at West Cameron Block 167 to the Johnson Bayou facility, where it interconnects with one intrastate and four interstate pipeline systems. UTOS also owns the Johnson Bayou facility, which provides primarily natural gas and liquids separation and natural gas dehydration for natural gas transported on the HIOS and UTOS systems. ANR operates the UTOS system.

The following selected unaudited pro forma information represents Leviathan's consolidated results of operations on a pro forma basis for the six month periods ended June 30, 1999 and 1998, assuming the HIOS/UTOS acquisition, the acquisition of certain lateral pipelines and the effects of becoming the operator of Stingray had occurred on January 1, 1998.

	SIX MONTHS ENDED JUNE 30,	
	1999	1998
	(IN THOUSANDS EXCEPT PER UNIT AMOUNTS)	
Revenue	$47,755	$38,485
Operating income	$22,896	$10,392
Net income (loss)	$ 6,882	$ (230)
Basic and diluted net income (loss) per unit	$ 0.23	$ (0.01)

NOTE 3 -- EQUITY INVESTMENTS:

Leviathan's ownership interest in each of the Equity Investees is included in the summarized financial information that follows:

SUMMARIZED HISTORICAL OPERATING RESULTS
SIX MONTHS ENDED JUNE 30, 1999
(IN THOUSANDS)
(UNAUDITED)

	HIOS(A)	UTOS(A)	VIOSCA KNOLL(B)	STINGRAY	WEST CAMERON DEHY	POPCO	MANTA RAY OFFSHORE(C)	NAUTILUS(C)	TOTAL
Operating revenue......	$19,350	$2,119	$12,338	$ 9,068	$1,475	$36,217	$ 7,780	$ 4,453	
Other income...........	118	33	31	1,105	13	191	1,144	(123)	
Operating expenses.....	(8,649)	(1,074)	(925)	(5,569)	(142)	(3,814)	(1,997)	(698)	
Depreciation...........	(2,321)	(280)	(1,752)	(3,800)	(8)	(2,301)	(2,523)	(2,964)	
Interest expense.......	--	--	(1,973)	(858)	--	(4,220)	(18)	(182)	
Net earnings (loss)....	8,498	798	7,719	(54)	1,338	26,073	4,386	486	
Ownership percentage...	40%	33.3%	50%	50%	50%	36%	25.67%	25.67%	
	3,399	266	3,860	(27)	669	9,386	1,126	125	
Adjustments:									
Depreciation(d)......	354	17	--	400	--	(60)	(174)	--	
Contract amortization(d)....	(53)	--	--	--	--	--	--	--	
Other................	(2)	3	--	721(e)	--	--	--	(57)	
Equity in earnings.....	$3,698	$ 286	$ 3,860	$ 1,094	$ 669	$ 9,326	$ 952	$ 68	$19,953
Distributions(f).......	$4,200	$ 333	$ 6,350	$ 2,501	$ 550	$ 7,463	$ 1,954	$ 757	$24,108

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(a) As a result of restructuring the joint venture arrangement in December 1998, the partners of HIOS, (i) created a holding company, Western Gulf, (ii) converted the HIOS Delaware partnership into a limited liability company and (iii) formed East Breaks. HIOS owns a regulated natural gas system, and East Breaks is currently constructing an unregulated natural gas system. Leviathan believes the disclosure of separate financial data for HIOS and East Breaks is more meaningful than the consolidated results of Western Gulf. East Breaks has had only construction activity since its inception. On June 30, 1999, Leviathan acquired additional interests in HIOS, East Breaks and UTOS (see Note 2). As a result of the additional interests acquired, Leviathan owns an effective 60% interest in each of HIOS and East Breaks and a 66.7% interest in UTOS.

(b) The information presented for Viosca Knoll as an equity investment is through May 31, 1999. On June 1, 1999, Leviathan began consolidating the results of Viosca Knoll as a result of acquiring an additional 49% interest in Viosca Knoll (see Note 2).

(c) Leviathan owns a 25.67% interest in each of Neptune and Ocean Breeze, which together own 100% of the member interests in each of Manta Ray Offshore, which owns an unregulated natural gas system, and Nautilus, which owns a regulated natural gas system. Leviathan believes the disclosure of separate financial data for Manta Ray Offshore and Nautilus is more meaningful than the consolidated results of Neptune and Ocean Breeze.

(d) Adjustments result from purchase price adjustments made in accordance with Accounting Principles Board ("APB") Opinion No. 16, "Business Combinations."

(e) Adjustments primarily resulting from changes in prior period estimates of reserves for uncollectible revenue.

(f) Future distributions are at the discretion of the Equity Investees' management committees and could further be restricted by the terms of the Equity Investees' respective credit agreements.

SUMMARIZED HISTORICAL OPERATING RESULTS
SIX MONTHS ENDED JUNE 30, 1998
(IN THOUSANDS)
(UNAUDITED)

	HIOS	UTOS	VIOSCA KNOLL	STINGRAY	WEST CAMERON DEHY	POPCO	MANTA RAY OFFSHORE(A)	NAUTILUS(A)	TOTAL
Operating revenue	$21,730	$ 2,384	$14,746	$11,620	$1,191	$19,517	$ 5,234	$ 1,289	
Other income	134	57	23	434	2	145	184	17	
Operating expenses	(8,632)	(1,260)	(1,263)	(7,611)	(84)	(1,960)	(1,533)	(678)	
Depreciation	(2,384)	(279)	(1,893)	(3,489)	(7)	(4,392)	(2,129)	(2,890)	
Interest expense	--	--	(1,989)	(1,069)	--	(4,396)	--	(12)	
Net earnings (loss)	10,848	902	9,624	(115)	1,102	8,914	1,756	(2,274)	
Ownership percentage	40%	33.3%	50%	50%	50%	36%	25.67%	25.67%	
	4,339	301	4,812	(58)	551	3,209	451	(584)	
Adjustments:									
Depreciation(b)	379	16	--	406	--	--	(174)	--	
Contract amortization(b)	(53)	--	--	(122)	--	--	--	--	
Other	(69)	16	--	(24)	--	(60)	--	(765)(c)	
Equity in earnings (loss)	$ 4,596	$ 333	$ 4,812	$ 202	$ 551	$ 3,149	$ 277	$(1,349)	$12,571
Distributions	$ 5,240	$ 333	$ 5,800	$ 1,000	$ 425	$ --	$ 500	$ --	$13,298

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(a) Leviathan owns a 25.67% interest in each of Neptune and Ocean Breeze, which together own 100% of the member interests in each of Manta Ray Offshore, which owns an unregulated natural gas system, and Nautilus, which owns a regulated natural gas system. Leviathan believes the disclosure of separate financial data for Manta Ray Offshore and Nautilus is more meaningful than the consolidated results of Neptune and Ocean Breeze.

(b) Adjustments result from purchase price adjustments made in accordance with APB Opinion No. 16.

(c) Primarily relates to a revision of the allowance for funds used during construction ("AFUDC") which represents the estimated costs, during the construction period, of funds used for construction purposes.

NOTE 4 -- PROPERTY AND EQUIPMENT:

Property and equipment consist of the following (in thousands):

	JUNE 30, 1999 (UNAUDITED)	DECEMBER 31, 1998
Property and equipment, at cost		
Pipelines	$ 79,313	$ 64,464
Platforms and facilities	271,049	123,912
Oil and natural gas properties, at cost, using successful efforts method	155,931	152,750
	506,293	341,126
Less accumulated depreciation, depletion, amortization and impairment	125,083	99,134
Property and equipment, net	$381,210	$241,992

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

NOTE 5 -- BUSINESS SEGMENT INFORMATION:

The following table summarizes certain financial information for each business segment (in thousands):

	GATHERING, TRANSPORTATION AND PLATFORM SERVICES	OIL AND NATURAL GAS	EQUITY INVESTMENTS	SUBTOTAL	ELIMINATIONS AND OTHER	TOTAL
QUARTER ENDED JUNE 30, 1999:						
Revenue from external customers..........	$ 6,425	$ 8,295	$ 9,252	$ 23,972	$ --	$ 23,972
Intersegment revenue............	3,136	--	--	3,136	(3,136)	--
Depreciation, depletion and amortization.......	(2,323)	(4,686)	--	(7,009)	--	(7,009)
Operating income (loss)............	4,632	(1,177)	8,298	11,753	--	11,753
Net cash flows........	6,956	3,508	13,064	23,528	--	23,528
Segment assets........	310,609	77,871	222,038	610,518	15,395	625,913
QUARTER ENDED JUNE 30, 1998:						
Revenue from external customers..........	$ 4,522	$ 6,599	$ 7,252	$ 18,373	$ --	$ 18,373
Intersegment revenue............	2,486	--	--	2,486	(2,486)	--
Depreciation, depletion and amortization.......	(1,903)	(5,075)	--	(6,978)	--	(6,978)
Operating income (loss)............	2,700	(3,061)	6,494	6,133	--	6,133
Net cash flows........	4,603	2,014	6,215	12,832	--	12,832
Segment assets........	143,340	58,662	188,530	390,532	15,555	406,087
SIX MONTHS ENDED JUNE 30, 1999:						
Revenue from external customers..........	$ 10,798	$15,100	$ 19,953	$ 45,851	$ --	$ 45,851
Intersegment revenue............	6,010	--	--	6,010	(6,010)	--
Depreciation, depletion and amortization.......	(4,243)	(9,484)	--	(13,727)	--	(13,727)
Operating income (loss)............	7,642	(4,043)	17,591	21,190	--	21,190
Net cash flows........	11,885	5,441	21,746	39,072	--	39,072
Segment assets........	310,609	77,871	222,038	610,518	15,395	625,913
SIX MONTHS ENDED JUNE 30, 1998:						
Revenue from external customers..........	$ 7,782	$15,734	$ 12,571	$ 36,087	$ --	$ 36,087
Intersegment revenue............	5,075	--	--	5,075	(5,075)	--
Depreciation, depletion and amortization.......	(3,519)	(11,326)	--	(14,845)	--	(14,845)
Operating income (loss)............	3,129	(5,109)	10,173	8,193	--	8,193
Net cash flows........	6,648	6,217	10,900	23,765	--	23,765
Segment assets........	143,340	58,662	188,530	390,532	15,555	406,087

NOTE 6 -- FINANCING TRANSACTIONS:

Senior Subordinated Notes

Leviathan entered into an indenture dated May 27, 1999 with Chase Bank of Texas, National Association, pursuant to which it issued $175 million in aggregate principal amount of Senior Subordinated Notes (along with the indenture, the "Subordinated Notes"). Leviathan capitalized $5.2 million of debt issue costs related to the issuance of the Subordinated Notes. Approximately $19.9 million of the proceeds were used to consummate the Viosca Knoll acquisition (see Note 2), $33.4 million were contributed to Viosca Knoll to repay the remaining unpaid balance of the Viosca Knoll credit facility, and the remaining proceeds were used to reduce the balance outstanding of and to extend Leviathan's revolving credit facility (discussed below).

The Subordinated Notes bear interest at a rate of 10 3/8% per annum, payable semi-annually, on June 1 and December 1, mature on June 1, 2009 and are junior to substantially all of Leviathan's other indebtedness other than trade payables and indebtedness that by its terms expressly states it is equal or junior to the Subordinated Notes. Generally, Leviathan does not have the right to prepay the Subordinated Notes prior to May 31, 2004 and thereafter, Leviathan may prepay the Subordinated Notes at a premium of 5% of the face amount, which premium declines ratably through maturity. Although the Subordinated Notes are unsecured, all of Leviathan's subsidiaries have guaranteed those obligations. The Subordinated Notes contain customary terms and conditions, including various affirmative and negative covenants and the obligation to offer to repurchase the notes at a premium under certain circumstances. Among other things, the terms of the Subordinated Notes limit Leviathan's ability to make distributions to its unitholders, redeem or otherwise reacquire any of its equity, incur additional indebtedness, incur or permit to exist certain liens, make additional investments, engage in transactions with affiliates, engage in certain types of businesses and dispose of assets under certain circumstances, including if certain financial tests are not satisfied or there is a default. In addition, Leviathan will be obligated to offer to repurchase the Subordinated Notes if it experiences certain types of changes of control or if it disposes of certain assets and does not reinvest the proceeds or repay senior indebtedness. Also, Leviathan agreed to file a registration statement for an offer to exchange the Subordinated Notes for debt securities with identical terms and to complete the registered exchange offer within 180 days after June 1, 1999.

Leviathan Credit Facility

Concurrent with the closing of the offering of the Subordinated Notes, Leviathan amended and restated its $375 million credit facility (the "Leviathan Credit Facility") to, among other things, extend its maturity from December 1999 to May 2002. Leviathan incurred approximately $3.0 million related to the amendment and restatement of the credit facility. The Leviathan Credit Facility, as amended, is a revolving credit facility with a syndicate of commercial banks providing for up to $375 million of available credit, subject to customary terms and conditions, including certain limitations on incurring additional indebtedness (including borrowings under this facility) if certain financial targets are not achieved and maintained. In addition, Leviathan will be required to prepay a portion of the balance outstanding under this credit facility to the extent such financial targets are not achieved and maintained. Funds borrowed under the Leviathan Credit Facility are available to Leviathan for general partnership purposes, including financing capital expenditures, working capital requirements and, subject to certain limitations, distributions to the unitholders. The Leviathan Credit Facility can also be utilized to issue letters of credit as may be required from time to time; however, no letters of credit are currently outstanding. The Leviathan Credit Facility, as amended, matures in May 2002; is guaranteed by the General Partner and each of Leviathan's subsidiaries; and is collateralized by (i) the management agreement between the General Partner and a subsidiary of El Paso Energy, (ii) substantially all of the assets of Leviathan and its subsidiaries and (iii) the General Partner's 1% general partner interest in Leviathan and approximate 1% nonmanaging member interest in certain subsidiaries of Leviathan. The Leviathan Credit Facility has no scheduled amortization prior to maturity. As of June 30, 1999, Leviathan had $306.5 million outstanding under its credit facility bearing interest at an average floating rate of 7.5% per annum.

NOTE 7 -- PARTNERS' CAPITAL INCLUDING CASH DISTRIBUTIONS:

Cash distributions

Leviathan paid cash distributions of $0.275 per Preference Unit and $0.525 per Common Unit for each of the three months ended December 31, 1998 and March 31, 1999 in February 1999 and May 1999, respectively. As a result, the General Partner received incentive distributions of $5.6 million for the six months ended June 30, 1999. On July 19, 1999, Leviathan declared a cash distribution of $0.275 per Preference Unit and $0.525 per Common Unit for the three months ended June 30, 1999 which was paid on August 13, 1999, to all holders of record of Common Units and Preference Units as of July 30, 1999. The General Partner was paid an incentive distribution of $3.2 million for the quarter ended June 30, 1999. At the current distribution rates, the General Partner receives approximately 19% of total cash distributions paid by Leviathan and is thus allocated approximately 19% of Leviathan's net income.

Conversion of Preference Units into Common Units

On May 14, 1999, Leviathan notified the holders of its 1,016,906 then outstanding Preference Units of their opportunity to submit their Preference Units for conversion into an equal number of Common Units during a 90-day period. During the conversion period, 725,607 Preference Units were converted into an equal number of Common Units. The remaining 291,299 Preference Units will retain their distribution preferences over the Common Units; that is, no Common Unitholder or the General Partner will receive any quarterly distribution until each Preference Unitholder has received the minimum quarterly distribution of $0.275 per unit plus any arrearages. Holders of the Common Units and the General Partner are entitled to distributions in excess of $0.275 per unit. Preference Units are not entitled to any such excess distributions.

Holders of Preference Units will have a third and final conversion opportunity in May 2000. Thereafter, any remaining Preference Units may, in certain circumstances, be subject to mandatory redemption at below market trading prices. Further, following this most recent conversion opportunity period, the Preference Units may no longer meet New York Stock Exchange minimum listing requirements and may be delisted.

NOTE 8 -- NET INCOME PER UNIT:

Basic and diluted net income per unit is calculated based upon the net income of Leviathan less an allocation of net income to the General Partner proportionate to its share of cash distributions and is presented below for the quarters and six months ended June 30, 1999 and 1998 (in thousands).

	QUARTER ENDED JUNE 30,					
	1999			1998		
	LIMITED PARTNERS	GENERAL PARTNER	TOTAL	LIMITED PARTNERS	GENERAL PARTNER	TOTAL
Net income(a)	$4,146	$ 42	$4,188	$1,495	$ 15	$1,510
Allocation to General Partner(b)	(753)	753	--	(277)	277	--
Allocation of net income as adjusted for incentive distributions	$3,393	$ 795	$4,188	$1,218	$292	$1,510
Weighted average number of units outstanding(c)	25,244			24,367		
Basic and diluted net income per unit	$ 0.13			$ 0.05		

	SIX MONTHS ENDED JUNE 30,					
	1999			1998		
	LIMITED PARTNERS	GENERAL PARTNER	TOTAL	LIMITED PARTNERS	GENERAL PARTNER	TOTAL
Net income(a)	$ 7,610	$ 77	$7,687	$ 85	$ 1	$ 86
Allocation to General Partner(b)	(1,382)	1,382	--	(16)	16	--
Allocation of net income as adjusted for incentive distributions	$ 6,228	$1,459	$7,687	$ 69	$ 17	$ 86
Weighted average number of units outstanding(c)	24,808			24,367		
Basic and diluted net income per unit	$ 0.25			$ 0.00		

(a) Net income is initially allocated 99% to the limited partners as holders of the Preference and Common Units and 1% to the General Partner (see (b)).

(b) Represents allocation of net income to the General Partner proportionate to its share of each quarter's cash distributions which included incentive distributions (see Note 7).

(c) Diluted weighted average number of units outstanding for 1999 is less than 1,000 units higher than basic weighted average units outstanding as a result of unit options included in the diluted weighted average.

NOTE 9 -- RELATED PARTY TRANSACTIONS:

Management fees

Leviathan's partnership agreement provides for reimbursement of expenses incurred by the General Partner, including reimbursement of expenses incurred by El Paso Energy in providing management services to Leviathan, its subsidiaries and the General Partner. The General Partner charged Leviathan $2.3 million, $2.1 million, $4.7 million and $4.6 million for the quarters and six months ended June 30, 1999 and 1998, respectively.

NOTE 10 -- COMMITMENTS AND CONTINGENCIES:

Leviathan may utilize derivative financial instruments for purposes other than trading to manage its exposure to movements in interest rates and commodity prices. In accordance with procedures established by Leviathan's Board of Directors, Leviathan monitors current economic conditions and evaluates its expectations of future prices and interest rates when making decisions with respect to risk management.

Interest Rate Risk

Leviathan utilizes both fixed and variable rate long-term debt. Leviathan is exposed to some market risk due to the floating interest rate under its credit facility. Under the Leviathan Credit Facility, as amended, the remaining principal and the final interest payment are due in May 2002. As of August 9, 1999, Leviathan's credit facility had a principal balance of $300 million at an average floating interest rate of 7.7% per annum. A 1.5% increase in interest rates could result in a $4.5 million annual increase in interest expense on the existing principal balance. Leviathan is exposed to similar risk under the credit facilities and loan agreements entered into by its joint ventures. Leviathan has determined that it is not necessary to participate in interest rate-related derivative financial instruments because it currently does not expect significant short-term increases in the interest rates charged under its credit facility or the various joint venture credit facilities and loan agreements.

Commodity Price Risk

Leviathan hedges a portion of its oil and natural gas production to reduce its exposure to fluctuations in the market prices thereof. Leviathan uses commodity price swap transactions whereby monthly settlements are based on differences between the prices specified in the commodity price swap agreements and the settlement prices of certain futures contracts quoted on the NYMEX or certain other indices. Leviathan settles the commodity price swap transactions by paying the negative difference or receiving the positive difference between the applicable settlement price and the price specified in the contract. The commodity price swap transactions Leviathan uses differ from futures contracts in that there are no contractual obligations which require or allow for the future delivery of the product. The credit risk from Leviathan's price swap contracts is derived from the counterparty to the transaction, typically a major financial institution. Leviathan does not require collateral and does not anticipate nonperformance by this counterparty, which does not transact a sufficient volume of transactions with Leviathan to create a significant concentration of credit risk. Gains or losses resulting from hedging activities and the termination of any hedging instruments are initially deferred and included as an increase or decrease to oil and natural gas sales in the period in which the hedged production is sold. For the quarter and six months ended June 30, 1999 and 1998, Leviathan recorded a net gain (loss) of $(0.4) million, $0.6 million, $(0.7) million and $1.4 million, respectively, related to hedging activities.

As of June 30, 1999, Leviathan has open sales swap transactions for 10,000 MMbtu of natural gas per day for calendar 2000 at a fixed price to be determined at its option equal to the February 2000 Natural Gas Futures Contract on the NYMEX as quoted at any time during 1999 and January 2000, to and including the last two trading days of the February 2000 contract, minus $0.5450 per MMbtu. Additionally, Leviathan has open sales swap transactions of 10,000 MMbtu of natural gas per day at a fixed price to be determined at its option equal to the January 2000 Natural Gas Futures Contract on NYMEX as quoted at any time during 1999, to and including the last two trading days of the January 2000 contract, minus $0.50 per MMbtu.

At June 30, 1999, Leviathan had open crude oil hedges on approximately 500 barrels per day for the remainder of calendar 1999 at an average price of $16.10 per barrel.

If Leviathan had settled its open oil and natural gas hedging positions as of June 30, 1999, based on the applicable settlement prices of the NYMEX futures contracts, Leviathan would have recognized a loss of approximately $2.2 million.

Other

Leviathan is involved from time to time in various claims, actions, lawsuits and regulatory matters that have arisen in the ordinary course of business, including various rate cases and other proceedings before the Federal Energy Regulatory Commission.

Leviathan and several subsidiaries of El Paso Energy have been made defendants in actions brought by Jack Grynberg on behalf of the United States Government under the false claims act. Generally, the complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Indian lands, thereby depriving the United States Government of royalties. In April 1999, the U.S. Government filed a notice that it does not intend to intervene in these actions. Grynberg has petitioned the Multidistrict Litigation Panel ("MLP") for consolidation of pre-trial matters. The MLP will not consider this matter until September 1999. Leviathan and El Paso Energy believe the complaint is without merit, and therefore, will not have a material adverse effect on Leviathan's consolidated financial position, results of operations or cash flows.

Leviathan is a defendant in a lawsuit filed by Transco Gas Pipe Line Corporation ("Transco") in the 157th Judicial District Court, Harris County, Texas on August 30, 1996. Transco alleges that, pursuant to a platform lease agreement entered into on June 28, 1994, Transco has the right to expand its facilities and operations on the offshore platform by connecting additional pipeline receiving and appurtenant facilities. Management has denied Transco's request to expand its facilities and operations because the lease agreement does not provide for such expansion and because Transco's activities will interfere with the Manta Ray Offshore system and Leviathan's existing and planned activities on the platform. Transco has requested a declaratory judgment and is seeking damages. The case is set for trial in November 1999. It is the opinion of management that adequate defenses exist and that the final disposition of this suit will not have a material adverse effect on Leviathan's consolidated financial position, results of operations or cash flows.

Leviathan is a named defendant in several lawsuits and a named party in several governmental proceedings arising in the ordinary course of business. While the outcome of such lawsuits or other proceedings against Leviathan cannot be predicted with certainty, management currently does not expect these matters to have a material adverse effect on Leviathan's consolidated financial position, results of operations or cash flows.

NOTE 11 -- NEW ACCOUNTING PRONOUNCEMENT NOT YET ADOPTED:

In June 1998, Statement of Financial Accounting Standards ("SFAS") No. 133, Accounting for Derivative Instruments and Hedging Activities, was issued by the Financial Accounting Standards Board to establish accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that entities recognize all derivative investments as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as a hedge transaction. For fair-value hedge transactions in which Leviathan is hedging changes in an asset's, liability's or firm commitment's fair value, changes in the fair value of the derivative instrument will generally be offset in the income statement by changes in the hedged item's fair value. For cash-flow hedge transactions in which Leviathan is hedging the variability of cash flows related to a variable-rate asset, liability, or a forecasted transaction, changes in the fair value of the derivative instrument will be reported in other comprehensive income. The gains and losses on the derivative instrument that are reported in other comprehensive income will be reclassified as earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The ineffective portion of all hedges will be recognized in current-period earnings. This statement was amended by SFAS No. 137 issued in June 1999. The amendment defers the effective date of SFAS No. 133 to fiscal years beginning after June 15, 2000. Leviathan is currently evaluating the effects of this pronouncement.

NOTE 12 -- SUBSEQUENT EVENTS:

In August 1999, Leviathan and Tejas Energy, L.L.C. ("Tejas") formed Nemo Gathering Company, LLC ("Nemo") to build a new pipeline (the "Nemo Pipeline") to gather natural gas from the deepwater region of the Gulf.

Nemo, owned 66.08% by Tejas and 33.92% by Leviathan, has entered into a gas gathering agreement with Shell Deepwater Development Inc. ("Shell") and will construct a 24-mile, 20-inch gas gathering line connecting Shell's planned Brutus development with the existing Manta Ray Offshore Gathering System. Gas production from the Brutus development is expected to commence in late 2001. Tejas will operate the line once it is constructed.

Shell plans to install a tension leg platform to develop its Brutus discovery at Green Canyon Block 158 in 2,980 feet of water. The Nemo Pipeline will interconnect with the Manta Ray Offshore Gathering System at Leviathan's platform located in Ship Shoal Block 332.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Unitholders of Leviathan Gas Pipeline Partners, L.P.
and the Board of Directors and Stockholder of
Leviathan Gas Pipeline Company, as General Partner

In our opinion, the accompanying consolidated balance sheet and related consolidated statements of operations, of cash flows and of partners' capital present fairly, in all material respects, the financial position of Leviathan Gas Pipeline Partners, L.P. and its subsidiaries ("Leviathan") at December 31, 1998 and 1997 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998 in conformity with generally accepted accounting principles. These financial statements are the responsibility of Leviathan'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 generally accepted auditing standards 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 the opinion expressed above.

PricewaterhouseCoopers LLP

Houston, Texas
March 19, 1999

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET
(In thousands)

	DECEMBER 31, 1998	DECEMBER 31, 1997
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,108	$ 6,430
Accounts receivable	1,482	1,953
Accounts receivable from affiliates	7,106	6,608
Other current assets	247	653
Total current assets	11,943	15,644
Equity investments	186,079	182,301
Property and equipment:		
Pipelines	64,464	78,617
Platforms and facilities	123,912	97,509
Oil and natural gas properties, at cost, using successful efforts method	152,750	120,296
	341,126	296,422
Less accumulated depreciation, depletion, amortization and impairment	99,134	95,783
Property and equipment, net	241,992	200,639
Investment in Tatham Offshore, Inc. (Notes 1 and 8)	--	7,500
Other noncurrent assets	2,712	3,758
Total assets	$442,726	$409,842
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 10,429	$ 12,522
Accounts payable to affiliates	738	1,032
Notes payable	338,000	--
Total current liabilities	349,167	13,554
Deferred federal income taxes	937	1,399
Notes payable	--	238,000
Other noncurrent liabilities	10,724	13,304
Total liabilities	360,828	266,257
Commitments and contingencies		
Minority interest	(998)	(381)
Partners' capital:		
Preference unitholders' interest	7,351	163,426
Common unitholders' interest	90,972	(15,400)
General Partner's interest	(15,427)	(4,060)
	82,896	143,966
Total liabilities and partners' capital	$442,726	$409,842

The accompanying notes are an integral part of this financial statement.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS
(In thousands, except per Unit amounts)

	YEAR ENDED DECEMBER 31,		
	1998	1997	1996
Revenue:			
Oil and natural gas sales	$ 186	$ 276	$ 772
Oil and natural gas sales to affiliates	31,225	57,830	46,296
Gathering, transportation and platform services	13,924	10,029	13,974
Gathering, transportation and platform services to affiliates	3,396	7,300	10,031
Equity in earnings	26,724	29,327	20,434
	75,455	104,762	91,507
Costs and expenses:			
Operating expenses	11,369	11,352	9,068
Depreciation, depletion and amortization	29,267	46,289	31,731
Impairment, abandonment and other	(1,131)	21,222	--
General and administrative expenses	6,416	5,869	788
Management fee and general and administrative expenses allocated from General Partner	9,773	8,792	7,752
	55,694	93,524	49,339
Operating income	19,761	11,238	42,168
Interest income and other	771	1,475	1,710
Interest and other financing costs	(20,242)	(14,169)	(5,560)
Minority interest in (income) loss	(15)	7	(427)
Income (loss) before income taxes	275	(1,449)	37,891
Income tax benefit	471	311	801
Net income (loss)	$ 746	$ (1,138)	$38,692
Weighted average number of units outstanding	24,367	24,367	24,367
Basic and diluted net income (loss) per unit (Note 2)	$ 0.02(a)	$ (0.06)	$ 1.57

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(a) Excludes 933,000 outstanding unit options to purchase an equal number of Common Units of Leviathan as the exercise prices of the unit options were greater than the average market price of the Common Units (Note 7).

The accompanying notes are an integral part of this financial statement.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS
(In thousands)

	YEAR ENDED DECEMBER 31,		
	1998	1997	1996
Cash flows from operating activities:			
Net income (loss)	$ 746	$ (1,138)	$ 38,692
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Amortization of debt issue costs	2,128	960	1,351
Depreciation, depletion and amortization	29,267	46,289	31,731
Impairment, abandonment and other	(1,131)	21,222	--
Minority interest in income (loss)	15	(7)	427
Equity in earnings	(26,724)	(29,327)	(20,434)
Distributions from equity investments	31,171	27,135	36,823
Deferred income taxes and other	(462)	(323)	(936)
Other noncash items	(310)	(1,596)	(6,560)
Changes in operating working capital:			
Decrease (increase) in accounts receivable	471	4,284	(3,442)
(Increase) decrease in accounts receivable from affiliates	(498)	7,499	(7,512)
Decrease (increase) in other current assets	406	206	(97)
Decrease in accounts payable and accrued liabilities	(9,108)	(5,247)	(23,190)
(Decrease) increase in accounts payable to affiliates	(294)	(2,472)	3,326
Net cash provided by operating activities	25,677	67,485	50,179
Cash flows from investing activities:			
Acquisition and development of oil and natural gas properties	(30,548)	(11,249)	(59,599)
Additions to pipelines, platforms and facilities	(27,368)	(30,708)	(30,095)
Equity investments	(8,195)	--	(12,027)
Proceeds from sales of assets and other	487	188	--
Net cash used in investing activities	(65,624)	(41,769)	(101,721)
Cash flows from financing activities:			
Decrease in restricted cash	--	716	--
Debt issue costs	(928)	(93)	(2,843)
Proceeds from notes payable	129,000	65,000	89,220
Repayments of notes payable	(29,000)	(54,000)	--
Distributions to partners	(62,447)	(47,398)	(33,852)
Net cash provided by (used in) financing activities	36,625	(35,775)	52,525
Net (decrease) increase in cash and cash equivalents	(3,322)	(10,059)	983
Cash and cash equivalents at beginning of year	6,430	16,489	15,506
Cash and cash equivalents at end of year	$ 3,108	$ 6,430	$ 16,489

Supplemental disclosures to the statement of cash flows -- see Note 11.

The accompanying notes are an integral part of this financial statement.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
(In thousands)

	PREFERENCE UNITS	PREFERENCE UNITHOLDERS	COMMON UNITS	COMMON UNITHOLDERS	GENERAL PARTNER(A)	TOTAL
Partners' capital at December 31, 1995	18,075	$ 192,225	6,292	$ (5,380)	$ (4)	$186,841
Net income for the year ended December 31, 1996	--	28,400	--	9,905	387	38,692
Cash distributions	--	(24,401)	--	(8,494)	(615)	(33,510)
Partners' capital at December 31, 1996	18,075	196,224	6,292	(3,969)	(232)	192,023
Net loss for the year ended December 31, 1997	--	(1,167)	--	(420)	449	(1,138)
Cash distributions	--	(31,631)	--	(11,011)	(4,277)	(46,919)
Partners' capital at December 31, 1997	18,075	163,426	6,292	(15,400)	(4,060)	143,966
Net income for the year ended December 31, 1998	--	63	--	541	142	746
Conversion of Preference Units into Common Units (Note 7)	(17,058)	(127,842)	17,058	127,842	--	--
Cash distributions	--	(28,296)	--	(22,011)	(11,509)	(61,816)
Partners' capital at December 31, 1998	1,017	$ 7,351	23,350	$ 90,972	$(15,427)(b)	$ 82,896

(a) Leviathan Gas Pipeline Company owns a 1% general partner interest in Leviathan Gas Pipeline Partners, L.P.

(b) Pursuant to the terms of the Partnership Agreement, no partner shall have any obligation to restore any negative balance in its capital account upon liquidation of Leviathan. Therefore, any net gains from the dissolution of Leviathan's assets would be allocated first to any then-outstanding deficit capital account balance before any of the remaining net proceeds would be distributed to the partners in accordance with their ownership percentages.

The accompanying notes are an integral part of this financial statement.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 -- ORGANIZATION:

Leviathan Gas Pipeline Partners, L.P., a publicly held Delaware limited partnership ("Leviathan"), is primarily engaged in the gathering, transportation and production of natural gas and crude oil in the Gulf of Mexico (the "Gulf"). Through its subsidiaries and joint ventures, Leviathan owns interests in significant assets, including (i) eight natural gas pipelines, (ii) a crude oil pipeline system, (iii) six strategically located multi-purpose platforms, (iv) a dehydration facility, (v) four producing oil and natural gas properties and (vi) one undeveloped oil and natural gas property.

Leviathan Gas Pipeline Company, a Delaware corporation and the general partner of Leviathan (the "General Partner"), performs all management and operational functions of Leviathan and its subsidiaries. In August 1998, the General Partner became a wholly-owned indirect subsidiary of El Paso Energy Corporation ("El Paso") pursuant to El Paso's merger with DeepTech International Inc. ("DeepTech"), the indirect parent of the General Partner, as discussed below.

Merger

Effective August 14, 1998, El Paso completed the acquisition of DeepTech by merging a wholly-owned subsidiary of El Paso with and into DeepTech (the "Merger") pursuant to the Agreement and Plan of Merger dated as of February 27, 1998 (as amended, the "Merger Agreement"). The material terms of the Merger and the transactions contemplated by the Merger Agreement and other agreements as these agreements relate to Leviathan are as follows:

(a) Prior to the Merger, Leviathan Holdings Company, which owns 100% of the General Partner, was owned 85% by DeepTech resulting in DeepTech owning an overall 23.2% effective interest in Leviathan. El Paso acquired the minority interests of Leviathan Holdings Company and two other subsidiaries of DeepTech primarily held by former DeepTech management for an aggregate of $55.0 million. As a result, El Paso owns 100% of the General Partner's interest in Leviathan and an overall 27.3% effective interest in Leviathan.

(b) In June 1998, Tatham Offshore, Inc. ("Tatham Offshore"), an affiliate of Leviathan through August 14, 1998, canceled its reversionary interests in certain oil and natural gas properties owned by Leviathan (Note 4).

(c) On August 14, 1998, Tatham Offshore transferred its remaining assets located in the Gulf to Leviathan in exchange for the 7,500 shares of Series B 9% Senior Convertible Preferred Stock (the "Senior Preferred Stock") issued by Tatham offshore (Note 8) and owned by Leviathan (the "Redemption Agreement"). Under the terms of the Redemption Agreement, Leviathan acquired all of Tatham Offshore's right, title and interest in and to Viosca Knoll Blocks 817 (subject to an existing production payment obligation), West Delta Block 35, the platform located at Ship Shoal Block 331 and other lease blocks not material to Leviathan's current operations. The net cash expenditure of Leviathan under the Redemption Agreement totaled $774,000 representing (i) $2,771,000 of abandonment costs relating to wells located at Ewing Bank Blocks 914 and 915 offset by (ii) $1,997,000 of net cash generated from the producing properties from January 1, 1998 through August 14, 1998. In addition, Leviathan assumed all remaining abandonment and restoration obligations associated with the platform and leases.

NOTE 2 -- SIGNIFICANT ACCOUNTING POLICIES:

Principles of consolidation

The accompanying consolidated financial statements include the accounts of those 50% or more owned subsidiaries controlled by Leviathan. The General Partner's approximate 1% nonmanaging interest in certain subsidiaries of Leviathan represents the minority interest in Leviathan's consolidated financial statements. Investments in which Leviathan owns a 20% to 50% ownership interest are accounted for using the equity method. All significant intercompany balances and transactions have been eliminated in consolidation. Certain amounts from the prior year have been reclassified to conform to the current year's presentation.

Cash and cash equivalents

All highly liquid investments with a maturity of three months or less when purchased are considered to be cash equivalents.

Property and equipment

Gathering pipelines, platforms and related facilities are recorded at cost and are depreciated on a straight-line basis over the estimated useful lives of the assets which generally range from 5 to 30 years for the gathering pipelines and from 18 to 30 years for platforms and the related facilities. Repair and maintenance costs are expensed as incurred; additions, improvements and replacements are capitalized.

Leviathan accounts for its oil and natural gas exploration and production activities using the successful efforts method of accounting. Under this method, costs of successful exploratory wells, development 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. Repair and maintenance costs are charged to expense as incurred; additions, improvements and replacements are capitalized.

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. Other noncurrent liabilities at December 31, 1998 and 1997 include $10,724,000 and $9,158,0000, respectively, of accrued dismantlement, restoration and abandonment costs.

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.

Leviathan evaluates impairment of its property and equipment in accordance with Statement of Financial Accounting Standard ("SFAS") No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," which requires recognition of impairment losses on long-lived assets (including pipelines, proved properties, wells, equipment and related facilities) if the carrying amount of such assets, grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows from other assets, exceeds the estimated undiscounted future cash flows of such assets. Measurement of any impairment loss is based on the fair value of the assets.

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. Any unamortized debt issue costs are expensed at the time the related indebtedness is repaid or otherwise terminated.

Revenue recognition

Revenue from pipeline transportation of hydrocarbons is recognized upon receipt of the hydrocarbons into the pipeline systems. Revenue from oil and natural gas sales is recognized upon delivery in the period of production. Revenue from platform access and processing services is recognized in the period the services are provided.

Income taxes

Leviathan and its subsidiaries other than Tarpon Transmission Company ("Tarpon") are not taxable entities. However, the taxable income or loss resulting from the operations of Leviathan 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 acquisition of partnership units. Further, each partner's tax accounting, which is partially dependent upon his/her 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/her share of the net assets reported in the consolidated financial statements. Leviathan does not have access to information about each individual partner's tax attributes in Leviathan, and the aggregate tax bases cannot be readily determined. Accordingly, management does not believe that, in Leviathan's circumstances, the aggregate difference would be meaningful information.

Tarpon is, and Manta Ray Gathering Systems, Inc. ("Manta Ray") was, prior to its liquidation in May 1996, a subsidiary of Leviathan subject to federal corporate income taxation. Leviathan utilizes an asset and liability approach for accounting for income taxes of Tarpon and Manta Ray that requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the carrying amounts and tax bases of other assets and liabilities. Resulting tax liabilities, if any, are borne by Leviathan.

Net income per unit

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

Basic income (loss) per unit and diluted income (loss) per unit for Leviathan are the same for the years ended December 31, 1998, 1997 and 1996 as no dilutive potential units were outstanding during the respective periods. Leviathan includes the outstanding Preference Units in the basic and diluted net income (loss) per unit calculation as if the Preference Units had been converted into Common Units.

Basic and diluted net income (loss) per unit is calculated based upon the net income (loss) of Leviathan less an allocation of net income to the General Partner proportionate to its share of cash distributions and is calculated as follows (in thousands).

	YEAR ENDED DECEMBER 31, 1998			YEAR ENDED DECEMBER 31, 1997		
	LIMITED PARTNERS	GENERAL PARTNER	TOTAL	LIMITED PARTNERS	GENERAL PARTNER	TOTAL
Net income (loss)(a)	$ 738	$ 8	$746	$(1,127)	$(11)	$(1,138)
Allocation to General Partner(b)	(134)	134	--	(460)	460	--
Allocation of net income (loss) as adjusted for Incentive Distributions	$ 604	$142	$746	$(1,587)	$449	$(1,138)
Weighted average number of units outstanding	24,367			24,367		
Basic and diluted net income (loss) per unit	$ 0.02			$ (0.06)		

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(a) Net income (loss) allocated 99% to the limited partners as holders of the Preference and Common Units and 1% to the General Partner.

(b) Represents allocation of net income to the General Partner proportionate to its share of each quarter's cash distributions which included Incentive Distributions (Note 7).

For the year ended December 31, 1996, basic and diluted net income per unit was computed based upon the net income of Leviathan less an allocation of approximately 1% of Leviathan's net income to the General Partner. During 1996, the General Partner only received a 1% allocation of net income as Leviathan did not pay any Incentive Distributions (Note 7) until 1997. The weighted average number of Units outstanding for the year ended December 31, 1996 was 24,366,894 Units.

Estimates

The preparation of consolidated financial statements in conformity with generally accepted accounting principles and the estimation of oil and natural gas reserves requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the related reported amounts of revenue and expenses during the reporting period. Such estimates and assumptions include those regarding: (i) Federal Energy Regulatory Commission ("FERC") regulations, (ii) oil and natural gas reserve disclosure, (iii) estimated useful lives of depreciable assets and (iv) potential abandonment, dismantlement, restoration and environmental liabilities. Actual results could differ from those estimates. Management believes that its estimates are reasonable.

Unit Options

In August 1998, Leviathan adopted SFAS No. 123, "Accounting for Stock Based Compensation." While SFAS No. 123 encourages entities to adopt the fair value method of accounting for their stock-based compensation plans, this standard permits and Leviathan has elected to utilize the intrinsic value method under Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees." Prior to August 1998, compensation expense for Leviathan's unit appreciation rights was recorded annually based on the quoted market price of Preference Units at the end of the period and the percentage of vesting which had occurred. A description of Leviathan's option plans and pro forma information regarding net income (loss) and net income (loss) per unit, as calculated under the provisions of SFAS No. 123, are disclosed in Note 7.

Price Risk Management Activities

Leviathan enters into commodity price swap instruments for non-trading purposes to manage its exposure to price fluctuations on anticipated natural gas and crude oil sales transactions. To qualify for hedge accounting, the transactions must reduce the risk of the underlying hedge items, be designated as hedges at inception and result in cash flows and financial impacts which are inversely correlated to the position being hedged. If correlation ceases to exist, hedge accounting is terminated and mark-to-market accounting is applied. Gains and losses resulting from hedging activities and the termination of any hedging instruments are initially deferred and included as an increase or decrease to oil and natural gas sales in the period in which the hedged production is sold. See Note 10.

Recent Pronouncements

Effective January 1, 1998, Leviathan adopted SFAS No. 131, "Disclosures About Segments of an Enterprise and Related Information." SFAS No. 131 establishes standards for the method public entities report information about operating segments in both interim and annual financial statements issued to unitholders and requires related disclosures about products and services, geographic areas and major customers. See Notes 3, 4, 12 and 13.

In April 1998, the American Institute of Certified Public Accountants issued Statement of Position 98-5, "Reporting on the Costs of Start-Up Activities." This statement defines start-up activities, requires start-up and organization costs to be expensed as incurred and requires that any such costs that exist on the balance sheet be expensed upon adoption of this pronouncement. The statement is effective for fiscal years beginning after December 15, 1998. Leviathan does not expect the implementation of this statement to have a material effect on Leviathan's financial position or results of operations.

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that entities recognize all derivative instruments as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as a hedge transaction. For fair-value hedge transactions in which Leviathan is hedging changes in an asset's, liability's or firm commitment's fair value, changes in the fair value of the derivative instrument will generally be offset in the income statement by changes in the hedged item's fair value. For cash-flow hedge transactions, in which Leviathan is hedging the variability of cash flows related to a variable-rate asset, liability, or a forecasted transaction, changes in the fair value of the derivative instrument will be reported in other comprehensive income. The gains and losses on the derivative instrument that are reported in other comprehensive income will be reclassified as earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The ineffective portion of all hedges will be recognized in current-period earnings. This statement is effective for fiscal years beginning after June 15, 1999. Leviathan has not yet determined the impact that the adoption of SFAS No. 133 will have on its financial position or results of operations.

In November 1998, the Emerging Issues Task Force ("EITF") reached a consensus on EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." EITF 98-10 requires energy trading contracts to be recorded at fair value on the balance sheet, with the changes in fair value included in earnings and is effective for fiscal years beginning after December 15, 1998. Leviathan adopted the provisions of EITF 98-10 in January 1999 and does not believe that the application of this pronouncement will have a material impact on Leviathan's financial position or results of operations.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

NOTE 3 -- EQUITY INVESTMENTS:

Leviathan owns interests of 50% in Viosca Knoll Gathering Company ("Viosca Knoll"), 36% in Poseidon Oil Pipeline Company, L.L.C. ("POPCO"), 50% in Stingray Pipeline Company ("Stingray"), 40% in High Island Offshore System, L.L.C., ("HIOS"), 33 1/3% in U-T Offshore System ("UTOS"), 50% in West Cameron Dehydration Company, L.L.C. ("West Cameron Dehy") and an effective 25.67% interest in each of Manta Ray Offshore Gathering Company, L.L.C. ("Manta Ray Offshore") and Nautilus Pipeline Company, L.L.C. ("Nautilus").

The excess of the carrying amount of the investments accounted for using the equity method over the underlying equity in net assets as of December 31, 1998 is $45,023,000. The difference between the cost of the investments accounted for on the equity method and the underlying equity in net assets is being depreciated on a straight-line basis over the estimated lives of the underlying net assets.

The summarized financial information for investments, which are accounted for using the equity method, is as follows.

SUMMARIZED HISTORICAL OPERATING RESULTS
YEAR ENDED DECEMBER 31, 1998
(In thousands)

	HIOS	VIOSCA KNOLL	STINGRAY	POPCO	WEST CAMERON DEHY	UTOS	MANTA RAY OFFSHORE(A)	NAUTILUS(A)	TOTAL
Operating revenue........	$ 43,818	$29,334	$ 23,008	$44,522	$2,796	$ 5,174	$10,949	$ 5,403	
Other income.............	--	50	670	290	11	100	488	100	
Operating expenses.......	(19,047)	(3,031)	(16,814)	(4,763)	(183)	(2,466)	(3,710)	(1,979)	
Depreciation.............	(4,772)	(3,860)	(6,852)	(8,846)	(16)	(559)	(4,303)	(5,845)	
Interest expense.........	(16)	(4,267)	(1,668)	(8,671)	--	(2)	--	--	
Net earnings (loss)......	19,983	18,226	(1,656)	22,532	2,608	2,247	3,424	(2,321)	
Ownership percentage.....	40%	50%	50%	36%	50%	33.3%	25.67%	25.67%	
	7,993	9,113	(828)	8,111	1,304	749	879	(596)	
Adjustments:									
Depreciation(b)........	881	--	749	(120)	--	33	(348)	--	
Contract amortization(b)......	(105)	--	(127)	--	--	--	--	--	
Other..................	(149)	--	(49)	--	--	(52)	--	(714)(c)	
Equity in earnings (loss)................	$ 8,620	$ 9,113	$ (255)	$7,991	$1,304	$ 730	$ 531	$ (1,310)	$26,724
Distributions(d).........	$ 9,240	$10,350	$ 1,000	$6,732	$1,100	$ 933	$ 1,182	$ 634	$31,171

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(a) Leviathan owns a 25.67% interest in Neptune Pipeline Company, L.L.C. ("Neptune"). Neptune owns a 99% member interest in each of Manta Ray Offshore, which owns a non-jurisdictional natural gas system, and Nautilus, which owns a jurisdictional natural gas system. Leviathan believes the disclosure of separate financial data for Manta Ray Offshore and Nautilus is more meaningful than the consolidated results of Neptune.

(b) Adjustments result from purchase price adjustments made in accordance with APB Opinion No. 16 "Business Combinations."

(c) Primarily relates to a revision of the allowance for funds used during construction ("AFUDC") which represents the estimated costs, during the construction period, of funds used for construction.

(d) Future distributions could be restricted by the terms of the equity investees' respective credit agreements.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

SUMMARIZED HISTORICAL OPERATING RESULTS
YEAR ENDED DECEMBER 31, 1997
(In thousands)

	HIOS	VIOSCA KNOLL	STINGRAY	POPCO	WEST CAMERON DEHY	UTOS	MANTA RAY OFFSHORE(A)	NAUTILUS(A)	TOTAL
Operating revenue..........	$ 45,917	$23,128	$ 23,630	$26,161	$2,451	$ 3,785	$ 6,263	$ 54	
Other income...............	--	40	970	209	29	61	1,564	6,489(b)	
Operating expenses.........	(17,101)	(2,115)	(15,612)	(5,782)	(164)	(2,472)	(2,223)	(435)	
Depreciation...............	(4,774)	(2,474)	(7,216)	(6,463)	(16)	(566)	(1,823)	(233)	
Interest expense...........	--	(1,959)	(1,384)	(5,341)	--	37	(1,483)	--	
Net earnings...............	24,042	16,620	388	8,784	2,300	845	2,298	5,875	
Ownership percentage.......	40%	50%	50%	36%	50%	33.3%	25.67%	25.67%	
	9,617	8,310	194	3,162	1,150	281	590	1,508	
Adjustments:									
Depreciation(c)..........	845	--	959	(120)	--	35	--	--	
Contract amortization(c)........	(105)	--	(350)	--	--	--	--	--	
Other....................	(228)	--	(49)	(263)	--	(24)	3,082(d)	733	
Equity in earnings.........	$ 10,129	$ 8,310	$ 754	$2,779	$1,150	$ 292	$ 3,672	$2,241	$29,327
Distributions(e)...........	$ 12,200	$ 9,650	$ 1,375	$ --	$1,150	$ 200	$ 2,560	$ --	$27,135

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(a) Leviathan owns a 25.67% interest in Neptune. Neptune owns a 99% member interest in each of Manta Ray Offshore, which owns a non-jurisdictional natural gas system, and Nautilus, which owns a jurisdictional natural gas system. Leviathan believes the disclosure of separate financial data for Manta Ray Offshore and Nautilus is more meaningful than the consolidated results of Neptune.

(b) Includes $6,431,000 related to AFUDC. Recognition of this allowance is appropriate because it constitutes an actual cost of construction. For regulated activities, Nautilus is permitted to earn a return on and recover AFUDC through its inclusion in the rate base and the provision for depreciation. The rate employed for the equity component of AFUDC is the equity rate of return stated in Nautilus' FERC tariff.

(c) Adjustments result from purchase price adjustments made in accordance with APB Opinion No. 16 "Business Combinations."

(d) Represents additional net earnings specifically allocated to Leviathan related to the assets contributed by Leviathan to the Manta Ray Offshore joint venture. Pursuant to the terms of the joint venture agreement, Leviathan managed the operations of the assets contributed to Manta Ray Offshore and was permitted to retain approximately 100% of the net earnings from such assets during the construction phase of the expansion to the Manta Ray Offshore system (January 17, 1997 through December 31, 1997). Effective January 1, 1998, Manta Ray Offshore began allocating all net earnings in accordance with the ownership percentages of the joint venture.

(e) Future distributions could be restricted by the terms of the equity investees' respective credit agreements.

SUMMARIZED HISTORICAL OPERATING RESULTS
YEAR ENDED DECEMBER 31, 1996
(In thousands)

	HIOS	VIOSCA KNOLL	STINGRAY	POPCO	WEST CAMERON DEHY	UTOS	TOTAL
Operating revenue	$ 47,440	$13,923	$ 24,146	$7,819	$1,686	$ 3,476	
Other income	97	--	1,186	339	10	48	
Operating expenses	(15,683)	(424)	(14,260)	(3,042)	(162)	(2,511)	
Depreciation	(4,775)	(2,269)	(7,057)	(2,176)	(16)	(560)	
Other expenses	--	(90)	(1,679)	(269)	--	--	
Net earnings	27,079	11,140	2,336	2,671	1,518	453	
Ownership percentage	40%	50%	50%	36%	50%	33.3%	
	10,832	5,570	1,168	962	759	151	
Adjustments:							
Depreciation(a)	783	--	669	--	--	2	
Contract amortization(a)	(105)	--	--	--	--	--	
Rate refund reserve	(417)	--	--	--	--	--	
Other	(107)	--	--	167	--	--	
Equity in earnings	$ 10,986	$ 5,570	$ 1,837	$1,129	$ 759	$ 153	$20,434
Distributions	$ 11,400	$18,450	$ 1,923	$4,000	$ 650	$ 400	$36,823

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(a) Adjustments result from purchase price adjustments made in accordance with APB Opinion No. 16, "Business Combinations."

SUMMARIZED HISTORICAL BALANCE SHEETS
(In thousands)

	HIOS		VIOSCA KNOLL		STINGRAY		POPCO	
	DECEMBER 31,		DECEMBER 31,		DECEMBER 31,		DECEMBER 31,	
	1998	1997	1998	1997	1998	1997	1998	1997
Current assets	$ 4,662	$ 5,587	$ 5,451	$ 3,354	$ 17,892	$ 20,184	$ 43,338	$ 31,763
Noncurrent assets	12,936	12,081	97,758	98,004	50,109	42,541	233,082	226,055
Current liabilities	2,626	3,380	1,021	11,280	18,960	21,787	40,134	35,864
Long-term debt	--	--	66,700	52,200	20,583	11,600	131,000	120,500
Other noncurrent liabilities	--	199	340	256	12,924	5,289	--	--

	WEST CAMERON DEHY		UTOS		MANTA RAY OFFSHORE		NAUTILUS	
	DECEMBER 31,		DECEMBER 31,		DECEMBER 31,		DECEMBER 31,	
	1998	1997	1998	1997	1998	1997	1998	1997
Current assets	$ 848	$ 455	$ 4,699	$ 3,955	$ 7,250	$ 31,714	$ 2,782	$ 924
Noncurrent assets	647	663	2,745	2,803	135,626	127,731	113,434	120,074
Current liabilities	13	43	4,125	2,900	5,023	32,601	709	3,699

NOTE 4 -- OIL AND NATURAL GAS PROPERTIES:

Capitalized Costs

	DECEMBER 31,	
	1998	1997
	(In thousands)	
Proved properties	$ 53,313	$ 38,790
Wells, equipment and related facilities	99,437	81,506
Total capitalized costs	152,750	120,296
Accumulated depreciation, depletion and amortization	72,194	53,684
Net capitalized costs	$ 80,556	$ 66,612

Costs incurred in the Oil and Natural Gas Acquisitions, Exploration and Development Activities

	YEAR ENDED DECEMBER 31,	
	1998	1997
	(In thousands)	
Acquisitions of proved properties	$16,945	$ 1
Development	17,783	10,522
Capitalized interest	328	726
Total costs incurred	$35,056	$11,249

In October 1998, Leviathan purchased a 100% working interest in Ewing Bank Blocks 958, 959, 1002 and 1003 from a wholly-owned indirect subsidiary of El Paso for $12,235,000. In December 1998, Leviathan completed the drilling of a successful delineation well on the Ewing Bank unit.

In 1995, Leviathan entered into a purchase and sale agreement (the "Purchase and Sale Agreement") with Tatham Offshore pursuant to which Leviathan acquired, subject to certain reversionary rights, a 75% working interest in Viosca Knoll Block 817, a 50% working interest in Garden Banks Block 72 and a 50% working interest in Garden Banks Block 117 (the "Acquired Properties") from Tatham Offshore for $30 million. Leviathan was entitled to retain all of the revenue attributable to the Acquired Properties until it had received net revenue equal to the payout amount, whereupon Tatham Offshore was entitled to receive a reassignment of the Acquired Properties, subject to certain reductions and conditions. In connection with the Merger, Tatham Offshore canceled its reversionary interests in the Acquired Properties (Note 1).

NOTE 5 -- REGULATORY MATTERS:

The FERC has jurisdiction under the Natural Gas Act of 1938, as amended (the "NGA"), and the Natural Gas Policy Act of 1978, as amended (the "NGPA"), over Nautilus, Stingray, HIOS and UTOS (the "Regulated Pipelines") 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. Leviathan's remaining systems (the "Unregulated Pipelines") are gathering facilities and as such are not currently subject to rate and certificate regulation by the FERC under the NGA and the NGPA. However, the FERC has asserted that it has rate jurisdiction under the NGA over services performed through gathering facilities owned by a natural gas company (as defined in the NGA) when such services are performed "in connection with" transportation services provided by such natural gas company. Whether, and to what extent, the FERC will exercise any NGA rate jurisdiction it may be found to have over gathering facilities owned either by natural gas companies or affiliates thereof is subject to case-by-case review by the FERC. Based on current FERC policy and precedent, Leviathan does not anticipate that the FERC will assert or exercise any NGA rate jurisdiction over the Unregulated Pipelines so long as the services provided through such lines are not performed "in connection with" transportation services performed through any of the Regulated Pipelines. Both the Regulated and the Unregulated Pipelines are subject to the FERC's administration of the "equal access" requirements of the Outer Continental Shelf Lands Act ("OCSLA").

Poseidon is subject to regulation under the Hazardous Liquid Pipeline Safety Act ("HLPSA"). Operations in offshore federal waters are regulated by the Department of the Interior. In addition, as transporter of hydrocarbons across the Outer Continental Shelf ("OCS"), the Poseidon system must offer "equal access" to other potential shippers of crude. Poseidon is located in federal waters in the Gulf, and its right-of-way was granted by the federal government. Therefore, the FERC may assert that it has jurisdiction to compel Poseidon to grant access under OCSLA to other shippers of crude oil upon the satisfaction of certain conditions and to apportion the capacity of the line among owner and non-owner shippers.

The FERC has generally disclaimed jurisdiction to set rates for oil pipelines in the OCS under the Interstate Commerce Act. As a result, POPCO has not filed tariffs with the FERC for the Poseidon crude oil pipeline system.

Rate Cases

Tarpon. In March 1997, the FERC issued an order declaring Tarpon's facilities exempt from NGA regulation under the gathering exception, thereby terminating Tarpon's status as a "natural gas company" under the NGA. Tarpon has agreed, however, to continue service for shippers that have not executed replacement contracts on the terms and conditions, and at the rates reflected in, its last effective regulated tariff for two years from the date of the order.

Other. Each of Nautilus, Stingray, HIOS, and UTOS are currently operating under agreements with their respective customers that provide for rates that have been approved by the FERC.

NOTE 6 -- INDEBTEDNESS:

Leviathan has a revolving credit facility, as amended and restated (the "Leviathan Credit Facility"), with a syndicate of commercial banks to provide up to $375 million of available credit, subject to certain incurrence limitations. As of December 31, 1998 and 1997, Leviathan had $338 million and $238 million, respectively, outstanding under its credit facility. At the election of Leviathan, interest under the Leviathan Credit Facility is determined by reference to the reserve-adjusted London interbank offer rate ("LIBOR"), the prime rate or the 90-day average certificate of deposit. The interest rate at December 31, 1998 and 1997 was 7.1% and 6.6% per annum, respectively. A commitment fee is charged on the unused and available to be borrowed portion of the credit facility. This fee varies between 0.25% and 0.375% per annum and was 0.375% per annum at December 31, 1998. The amendment to the credit facility in January 1999 increased the commitment fee to 0.50% per annum. Amounts advanced under the Leviathan Credit Facility were used to finance Leviathan's capital expenditures, including construction of platforms and pipelines, investments in equity investees and the acquisition and development of oil and natural gas properties. Amounts remaining under the Leviathan Credit Facility are available to Leviathan for general partnership purposes, including financing capital expenditures, for working capital, and subject to certain limitations, for paying distributions to unitholders. The Leviathan Credit Facility can also be utilized to issue letters of credit as may be required from time to time; however, no letters of credit are currently outstanding. The Leviathan Credit Facility matures in December 1999; is guaranteed by Leviathan and each of Leviathan's subsidiaries; and is collateralized by the management agreement with Leviathan (Note 8), substantially all of the assets of Leviathan and the General Partner's 1% general partner interest in Leviathan and approximate 1% nonmanaging interest in certain subsidiaries of Leviathan. Management believes it will be able to extend or refinance this credit facility on acceptable terms and conditions prior to its maturity.

Interest and other financing costs totaled $21,308,000, $15,890,000 and $17,470,000 for the years ended December 31, 1998, 1997 and 1996, respectively. During the years ended December 31, 1998, 1997 and 1996, Leviathan capitalized $1,066,000, $1,721,000 and $11,910,000, respectively, of such interest costs in connection with construction projects and drilling activities in progress during such periods. At December 31, 1998 and 1997, the unamortized portion of debt issue costs totaled $2,549,000 and $3,749,000, respectively.

NOTE 7 -- PARTNERS' CAPITAL:

General

As of December 31, 1998, Leviathan had 23,349,988 Common Units and 1,016,906 Preference Units outstanding. Preference Units and Common Units totaling 18,075,000 are owned by the public, representing a 72.7% effective limited partner interest in Leviathan. The General Partner, through its ownership of a 25.3% limited partner interest in the form of 6,291,894 Common Units, its 1% general partner interest in Leviathan and its approximate 1% nonmanaging interest in certain subsidiaries of Leviathan, owns a 27.3% effective interest in Leviathan. See Note 14.

Conversion of Preference Units into Common Units

On May 7, 1998, Leviathan notified the holders of its 18,075,000 then outstanding Preference Units of their right to convert their Preference Units into an equal number of Common Units within a 90-day period. On August 5, 1998, the conversion period expired and holders of 17,058,094 Preference Units, representing approximately 94% of the Preference Units then outstanding, elected to convert to Common Units. As a result, the Preference Period, as defined in the Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement"), ended and the Common Units (including the 6,291,894 Common Units held by Leviathan) became the primary listed security on the New York Stock Exchange ("NYSE") under the symbol "LEV." A total of 1,016,906 Preference Units remain outstanding and trade as Leviathan's secondary listed security on the NYSE under the symbol "LEV.P". Leviathan reallocated partners' capital to reflect this conversion of Preference Units into Common Units.

The remaining Preference Units retain their distribution preferences over the Common Units; that is, holders of such Preference Units will be paid up to the minimum quarterly distribution of $0.275 per unit before any quarterly distributions are made to the Common Unitholders or the General Partner. However, holders of Preference Units will not receive any distributions in excess of the minimum quarterly distribution of $0.275 per unit. Only holders of Common Units and the General Partner will be eligible to receive any such excess distributions. See "Cash Distributions" below.

In accordance with the Partnership Agreement, holders of the remaining Preference Units will have the opportunity to convert their Preference Units into Common Units in May 1999 and May 2000. Thereafter, any remaining Preference Units may, under certain circumstances, be subject to redemption.

Cash Distributions

Leviathan makes quarterly distributions of 100% of its Available Cash, as defined in the Partnership Agreement, to its unitholders and the General Partner. Available Cash consists generally of all the cash receipts of Leviathan plus reductions in reserves less all of its cash disbursements and net additions to reserves. The General Partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to provide for the proper conduct of the business of Leviathan including cash reserves for future capital expenditures, to stabilize distributions of cash to the unitholders and the General

Partner, to reduce debt or as necessary to comply with the terms of any agreement or obligation of Leviathan. Leviathan expects to make distributions of Available Cash within 45 days after the end of each quarter to unitholders of record on the applicable record date, which will generally be the last business day of the month following the close of such calendar quarter.

The distribution of Available Cash for each quarter is subject to the preferential rights of the Preference Unitholders to receive the minimum quarterly distribution of $0.275 per unit for such quarter, plus any arrearages in the payment of the minimum quarterly distribution for prior quarters, if any, before any distribution of Available Cash is made to holders of Common Units for such quarter. The holders of Common Units are not entitled to arrearages in the payment of the minimum quarterly distribution. See the discussion above regarding distributions subsequent to the end of the Preference Period.

Since commencement of operations on February 19, 1993 through December 31, 1998, Leviathan has made distributions to the unitholders equal to and in excess of the minimum quarterly distribution of $0.275 per unit. See Note 16.

Distributions by Leviathan of its Available Cash are effectively made 98% to unitholders and 2% to the General Partner, subject to the payment of incentive distributions to the General Partner if certain target levels of cash distributions to unitholders are achieved ("Incentive Distributions"). As an incentive, the general partner's interest in the portion of quarterly cash distributions in excess of $0.325 per Unit and less than or equal to $0.375 per Unit is increased to 15%. For quarterly cash distributions over $0.375 per Unit but less than or equal to $0.425 per Unit, the general partner receives 25% of such incremental amount and for all quarterly cash distributions in excess of $0.425 per Unit, the general partner receives 50% of the incremental amount. During the years ended December 31, 1998, 1997 and 1996, the General Partner received Incentive Distributions totaling $11,113,000, $3,885,000 and $285,000, respectively. In February 1999, Leviathan paid a cash distribution of $0.275 per Preference Unit and $0.525 per Common Unit and an Incentive Distribution of $2,835,000 to the General Partner.

Unit Rights Appreciation Plan

In 1995, Leviathan adopted the Unit Rights Appreciation Plan (the "Plan") to provide Leviathan with the ability of making awards of unit rights to certain officers and employees of the General Partner or its affiliates as an incentive for these individuals to continue in the service of Leviathan or its affiliates. Under the Plan, Leviathan granted 1,200,000 unit rights to certain officers and employees of the General Partner or its affiliates that provided for the right to purchase, or realize the appreciation of, a Preference Unit or a Common Unit (a "Unit Right"), pursuant to the provisions of the Plan. The exercise prices covered by the Unit Rights granted pursuant to the Plan ranged from $15.6875 to $21.50, the closing prices of the Preference Units as reported on the NYSE on the grant date of the respective Unit Rights. For the years ended December 31, 1997 and 1996, Leviathan had accrued $3,710,000 and $436,000, respectively, related to the appreciation and vestiture of these Unit Rights through such dates. As a result of the "change in control" occurring upon the closing of the Merger, the Unit Rights fully vested and the holders of the Unit Rights elected to be paid $8,591,000, the amount equal to the difference between the grant price of the Unit Rights and the average of the high and the low sales price of the Common Units on the date of exercise. Upon the exercise of all of the Unit Rights outstanding, the Plan was terminated. Leviathan replaced the Plan with the Omnibus Plan discussed below.

Option Plans

In August 1998, Leviathan adopted the 1998 Omnibus Compensation Plan (the "Omnibus Plan") to provide the 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 3,000,000 Common Units of Leviathan may be issued pursuant to the Omnibus Plan. Unit options granted pursuant to the Omnibus Plan are not immediately exercisable. 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. The unit options shall expire ten years from such grant date, but shall be subject to earlier termination under certain circumstances.

In August 1998, Leviathan adopted the 1998 Unit Option Plan for Non-Employee Directors (the "Director Plan" and collectively with the Omnibus Plan, the "Option Plans") to provide the General Partner with the ability to issue unit options to attract and retain the services of knowledgeable directors. Unit options to purchase a maximum of 100,000 Common Units of Leviathan may be issued pursuant to the Director Plan. Each unit option granted under the Director Plan vests immediately at the date of grant and shall expire ten years from such date, but shall be subject to earlier termination in the event that the director ceases to be a director of the 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.

The following table summarizes the Option Plans as of and for the year ended December 31, 1998. No unit options had been granted by Leviathan prior to August 1998.

	NUMBER UNITS OF UNDERLYING OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at beginning of year	--	$ --
Granted	933,000	27.18
Exercised	--	--
Forfeited	--	--
Canceled	--	--
Outstanding at end of year	933,000(1)	$27.18(3)
Options Exercisable at end of year	3,000(2)	$26.17

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(1) The weighted average remaining contractual life approximates 9.8 years.

(2) The weighted average remaining contractual life approximates 9.6 years.

(3) The exercise prices for outstanding options range from $25.00 to $27.3438.

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: an expected volatility of 37%, a risk-free interest rate of 4.65%, an expected dividend yield of 8% and an expected term of 8 years. The weighted average fair value of the unit options granted during the year ended December 31, 1998 was $4.59. All of the unit options granted during 1998 were granted at market value on the date of grant.

Leviathan applied APB Opinion No. 25 and related interpretations in accounting for its Option Plans, under which no compensation expense has been recognized during 1998 as the exercise price of each grant equaled the market price on the date of grant. Had compensation costs for the Option Plans been determined consistent with the methodology prescribed by SFAS No. 123, Leviathan's net income and net income per unit would have been adjusted to a net loss of $461,000 or $0.015 per unit on a proforma basis. The effects of applying SFAS No. 123 in this pro forma disclosure are not indicative of future amounts.

NOTE 8 -- RELATED PARTY TRANSACTIONS:

Management Fees

Substantially all of the individuals who perform the day-to-day financial, administrative, accounting and operational functions for Leviathan as well as those who are responsible for the direction and control of Leviathan are currently employed by El Paso or were employed by DeepTech. Pursuant to a management agreement between DeepTech and the General Partner, a management fee is charged to the General Partner which is intended to approximate the amount of resources allocated by El Paso and/or DeepTech in providing various operational, financial, accounting and administrative services on behalf of the General Partner and Leviathan. The management agreement expires on June 30, 2002, and may be terminated thereafter upon 90 days notice by either party. Pursuant to the terms of the Partnership Agreement, the General Partner is entitled to reimbursement of all reasonable general and administrative expenses and other reasonable expenses incurred by the General Partner and its affiliates for or on behalf of Leviathan including, but not limited to, amounts payable by the General Partner to DeepTech under the management agreement.

Effective November 1, 1995, July 1, 1996 and July 1, 1997, primarily as a result of the increased activities of Leviathan, the General Partner amended its management agreement with DeepTech to provide for an annual management fee of 45.3%, 54% and 52%, respectively, of DeepTech's overhead. In connection with the Merger, the General Partner amended its management agreement with DeepTech to provide for a monthly management fee of $775,000. The General Partner charged Leviathan $9,283,000, $8,080,000 and $6,590,000 pursuant to its management agreement with DeepTech for the years ended December 31, 1998, 1997 and 1996, respectively.

The General Partner is also required to reimburse DeepTech for certain tax liabilities resulting from, among other things, additional taxable income allocated to the General Partner due to (i) the issuance of additional Preference Units (including the sale of the Preference Units by Leviathan pursuant to its second public offering) and (ii) the investment of such proceeds in additional acquisitions or construction projects. During the years ended December 31, 1998, 1997 and 1996, the General Partner charged Leviathan $489,000, $713,000 and $1,162,000, respectively, to compensate DeepTech for additional taxable income allocated to the General Partner.

Platform Access and Transportation Agreements

General. In 1993, Leviathan entered into a master gas dedication arrangement with Tatham Offshore (the "Master Dedication Agreement"). Under the Master Dedication Agreement, Tatham Offshore dedicated all production from its Viosca Knoll, Garden Banks, Ewing Bank and Ship Shoal leases as well as certain adjoining areas of mutual interest to Leviathan for transportation. In exchange, Leviathan agreed to install the pipeline facilities necessary to transport production from the areas and certain related facilities and to provide transportation services with respect to such production. Tatham Offshore agreed to pay certain fees for transportation services and facilities access provided under the Master Dedication Agreement. Pursuant to the terms of the Purchase and Sale Agreement (Note 4) and the Redemption Agreement (Note 1), a subsidiary of Leviathan assumed all of Tatham Offshore's obligations under the Master Dedication Agreement and certain ancillary agreements.

Viosca Knoll. For the years ended December 31, 1998, 1997 and 1996, Leviathan received $1,099,000, $1,973,000 and $1,896,000, respectively, from Tatham Offshore as platform access and processing fees related to Leviathan's platform located in Viosca Knoll Block 817.

For the years ended December 31, 1998, 1997 and 1996, Leviathan charged Viosca Knoll $2,447,000, $2,116,000 and $249,000, respectively, for expenses and platform access fees related to the Viosca Knoll Block 817 platform.

In addition, for the years ended December 31, 1998, 1997 and 1996, Viosca Knoll reimbursed $152,000, $47,000 and $254,000, respectively, to Leviathan for costs incurred by Leviathan in connection with the acquisition and installation of a booster compressor on Leviathan's Viosca Knoll Block 817 platform.

During the years ended December 31, 1998, 1997 and 1996, Viosca Knoll charged Leviathan $1,881,000, $3,921,000 and $3,229,000, respectively, for transportation services related to transporting production from the Viosca Knoll Block 817 lease.

Garden Banks. During the years ended December 31, 1998, 1997 and 1996, POPCO charged Leviathan $1,445,000, $2,003,000 and $1,056,000, respectively, for transportation services related to transporting production from the Garden Banks Block 72 and 117 leases.

Ewing Bank. Pursuant to a gathering agreement (the "Ewing Bank Agreement") among Tatham Offshore, DeepTech, and a subsidiary of Leviathan, Tatham Offshore dedicated all natural gas and crude oil produced from eight of its Ewing Bank leases for gathering and redelivery by Leviathan and was obligated to pay a demand and a commodity rate for shipment of all oil and natural gas under this agreement. Pursuant to the Ewing Bank Agreement, Leviathan constructed gathering facilities connecting Tatham Offshore's Ewing Bank 914 #2 well to a third party platform at Ewing Bank Block 826. For the years ended December 31, 1997 and 1996, Tatham Offshore paid Leviathan demand and commodity charges of $54,000 and $349,000, respectively, under this agreement. Additionally, through May 1997, Leviathan received revenue from the oil and natural gas production from the Ewing Bank 914 #2 well as a result of its 7.13% overriding royalty interest in the well. In 1995, Tatham Offshore experienced production problems with its Ewing Bank 914 #2 well and in March 1996, as a result of the continued production problems, Leviathan settled all remaining unpaid demand charge obligations under the Ewing Bank Agreement in exchange for certain consideration as discussed below.

Ship Shoal. Pursuant to the Master Dedication Agreement, Leviathan and Tatham Offshore entered into a gathering and processing agreement (the "Ship Shoal Agreement") pursuant to which Leviathan constructed a gathering line from Tatham Offshore's Ship Shoal Block 331 to interconnect with a third-party pipeline at Leviathan's platform and processing facilities located on Ship Shoal Block 332 in exchange for the dedication of all of the production from Tatham Offshore's Ship Shoal Block 331 and eight additional surrounding leases and receipt of a demand charge of $113,000 per month over a five-year period ending June 1999. During late 1994, all of Tatham Offshore's wells at Ship Shoal Block 331 experienced completion and production problems and in March 1996, as a result of the continued production problems, Leviathan settled all remaining unpaid demand charge obligations under this transportation agreement in exchange for certain consideration as discussed below.

Transportation Agreements Settled. Tatham Offshore was obligated to make demand charge payments to Leviathan pursuant to the Ewing Bank and Ship Shoal Agreements discussed above. However, production problems at Ship Shoal Block 331 and the Ewing Bank 914 #2 well affected Tatham Offshore's ability to pay the demand charge obligations under agreements relative to these properties. As a result, effective February 1, 1996, Leviathan released Tatham Offshore from all remaining demand charge payments under the Ewing Bank Agreement and the Ship Shoal Agreement, a total of $17,800,000. In exchange, Leviathan received 7,500 shares Senior Preferred Stock valued at $7,500,000 and added an additional $7,500,000 to the payout amount under the Purchase and Sale Agreement (Note 4), which was recorded as a noncurrent receivable. Pursuant to the Redemption Agreement, Leviathan exchanged the Senior Preferred Stock for Tatham Offshore's remaining assets located in the Gulf (Note 1).

During 1997, Tatham Offshore announced its intent to reserve its remaining costs associated with the Ewing Bank 914 #2 well and the three wellbores at Ship Shoal Block 331 as a result of production problems. In addition, Leviathan had determined that the designated net revenue from the Acquired

Properties (Note 4) was not likely to be sufficient to satisfy the payout amount and as such, would (i) retain 100% of the net revenue from the Acquired Properties, (ii) bear all abandonment obligations related to these properties and (iii) not realize the $7,500,000 plus accrued interest Leviathan had recorded as a noncurrent receivable related to the settlement of the Ewing Bank and Ship Shoal Agreements discussed above. Accordingly, in June 1997, Leviathan recorded as impairment, abandonment and other expense on the accompanying consolidated statement of operations a non-recurring charge of $21,222,000 to reserve its investment in certain gathering facilities and other assets associated with Tatham Offshore's Ewing Bank 914 #2 well and Ship Shoal Block 331 property ($6,443,000), to fully accrue its abandonment obligations associated with the gathering facilities serving these properties ($3,825,000), to reserve its noncurrent receivable related to the prepayment of the demand charge obligations under the Ewing Bank and Ship Shoal Agreements ($9,094,000) and to accrue certain abandonment obligations associated with its Viosca Knoll and Garden Banks properties ($1,860,000).

During 1998, Leviathan abandoned the Ewing Bank flowlines at a cost of $2,869,000 and recorded a credit to impairment, abandonment and other of $1,131,000, which represented the excess of the accrued costs over the actual costs incurred associated with the abandonment of the flowlines.

Other

Leviathan has agreed to sell all of its oil and natural gas production to Offshore Gas Marketing, Inc. ("Offshore Marketing"), an affiliate of Leviathan, on a month to month basis. The agreement with Offshore Marketing provides Offshore Marketing fees equal to 2% of the sales value of crude oil and condensate and $0.015 per dekatherm of natural gas for selling Leviathan's production. During the years ended December 31, 1998, 1997 and 1996, oil and natural gas sales to Offshore Marketing totaled $31,225,000, $57,830,000 and $46,296,000, respectively.

Pursuant to a management agreement between Viosca Knoll and Leviathan, Leviathan charges Viosca Knoll a base fee of $100,000 annually in exchange for Leviathan providing financial, accounting and administrative services on behalf of Viosca Knoll. For each of the years ended December 31, 1998, 1997 and 1996, Leviathan charged Viosca Knoll $100,000 in accordance with this management agreement.

For the years ended December 31, 1998 and 1997, Leviathan charged Manta Ray Offshore $1,274,000 and $287,000, respectively, pursuant to management and operations agreements.

Mr. Grant E. Sims and Mr. James H. Lytal entered into employment agreements with five year terms with El Paso pursuant to which they would continue to serve as Chief Executive Officer and President, respectively, of the General Partner and Leviathan. However, pursuant to the terms of their respective employment agreements, Messrs. Sims and Lytal have the right to terminate such agreements upon thirty days notice and El Paso has the right to terminate such agreements under certain circumstances.

Pursuant to the former Leviathan non-employee director compensation arrangements, Leviathan was obligated to pay each non-employee director 2 1/2% of the general partners' Incentive Distribution as a profit participation fee. During the years ended December 31, 1998 and 1997, Leviathan paid the three non-employee directors of Leviathan a total of $621,000 and $313,000, respectively, as a profit participation fee. As a result of the Merger, the three non-employee directors resigned and the compensation arrangements were terminated.

During the years ended December 31, 1997 and 1996, Leviathan was charged $3,351,000 and $7,223,000, respectively, by Sedco Forex Division of Schlumberger Technology Corporation ("Sedco Forex") for contract drilling services rendered by the semisubmersible drilling rig, the FPS Laffit Pincay, at its Garden Banks Block 117 project. The FPS Laffit Pincay was owned by an affiliate of DeepTech and managed by Sedco Forex during such period.

POPCO, which owns the Poseidon crude oil pipeline system, entered into certain agreements with a subsidiary of Leviathan which provided for POPCO's use of certain pipelines and platforms owned by such subsidiary for fees which consisted of a monthly rental fee of $100,000 per month for the period from February 1996 to January 1997 and reimbursement of $2,000,000 of capital expenditures incurred in readying one of the platforms for use.

In 1996, a subsidiary of Leviathan received a performance fee of $1,400,000 for managing the construction and installation of the initial 117 mile segment of the Poseidon crude oil pipeline system.

Mr. Charles M. Darling IV, a director of the General Partner and DeepTech through August 14, 1998, was a partner in a law firm until April 1997 that provided legal services to Leviathan. During the years ended December 31, 1997 and 1996, Leviathan incurred $55,000 and $203,000, respectively, for these services.

Dover Technology, Inc., which is 50% owned by DeepTech, performed certain technical and geophysical services for Leviathan in the aggregate amount of $240,000 for the year ended December 31, 1996.

NOTE 9 -- INCOME TAXES:

Leviathan (other than its subsidiaries, Tarpon and Manta Ray) is not subject to federal income taxes. Therefore, no recognition has been given to income taxes other than income taxes related to Tarpon and Manta Ray. The tax returns of Leviathan are subject to examination; if such examinations result in adjustments to distributive shares of taxable income or loss, the tax liability of partners could be adjusted accordingly.

Tarpon is and Manta Ray was, prior to its liquidation in May 1996, a subsidiary of Leviathan that files separate federal income tax returns. The income tax benefit recorded for the years ended December 31, 1998, 1997, and 1996 equals $471,000, $311,000 and $801,000, respectively, and is entirely related to Tarpon. The benefit equals Tarpon's book loss times the effective statutory rate for such period as no material book/tax permanent differences exist. Leviathan's deferred income tax liability at December 31, 1998 and 1997 of $937,000 and $1,399,000, respectively, is entirely related to the differences in the tax and book bases of the pipeline assets of Tarpon. In May 1996, Manta Ray was merged with and into a subsidiary of Leviathan. Manta Ray had no taxable income for the respective periods prior to its liquidation.

NOTE 10 -- COMMITMENTS AND CONTINGENCIES:

Credit Facilities

Each of POPCO, Viosca Knoll and Stingray are parties to a credit agreement under which it has outstanding obligations that may restrict the payment of distributions to its owners.

POPCO has a revolving credit facility, as amended, (the "POPCO Credit Facility") with a syndicate of commercial banks to provide up to $150 million for the construction and expansion of Poseidon and for other working capital needs of POPCO. POPCO's ability to borrow money under the facility is subject to certain customary terms and conditions, including borrowing base limitations. The POPCO Credit Facility is collateralized by a substantial portion of POPCO's assets and matures on April 30, 2001. As of December 31, 1998 and 1997, POPCO had $131,000,000 and $120,500,000, respectively, outstanding under its credit facility bearing interest at an average floating rate of 6.9% and 7.2% per annum, respectively. At December 31, 1998, POPCO had approximately $19,000,000 of additional funds available under the facility.

Viosca Knoll has a revolving credit facility, as amended, (the "Viosca Knoll Credit Facility") with a syndicate of commercial banks to provide up to $100 million for the addition of compression to and expansion of the Viosca Knoll system and for other working capital needs of Viosca Knoll, including funds for a one-time distribution of $25 million to its partners. In December 1996, Leviathan received a $12,500,000 distribution from Viosca Knoll as a result of its 50% interest in Viosca Knoll. Viosca Knoll's ability to borrow money under its credit facility is subject to certain customary terms and conditions, including borrowing base limitations. The Viosca Knoll Credit Facility is collateralized by all of Viosca Knoll's material contracts and agreements, receivables and inventory and matures on December 20, 2001. If Viosca Knoll fails to pay any principal, interest or other amounts due pursuant to the Viosca Knoll Credit Facility, Leviathan is obligated to pay up to a maximum of $2,500,000 in settlement of 50% of Viosca Knoll's obligations under the Viosca Knoll Credit Facility agreement. As of December 31, 1998 and 1997, Viosca Knoll had $66,700,000 and $52,200,000, respectively, outstanding under the Viosca Knoll Credit Facility bearing interest at an average floating rate of 6.7% per annum. At December 31, 1998, Viosca Knoll had approximately $33,300,000 of additional funds available under the facility. See Note 14.

In March 1998, Stingray amended an existing term loan agreement (the "Stingray Credit Agreement") to provide for additional borrowings of up to $11.1 million and to extend the maturity date of the loan from December 31, 2000 to March 31, 2003. The Stingray Credit Agreement requires Stingray to make 18 quarterly principal payments of $1,583,333 commencing December 31, 1998. The term loan agreement is principally collateralized by current and future natural gas transportation contracts between Stingray and its customers. As of December 31, 1998 and 1997, Stingray had $26,917,000 and $17,400,000, respectively, outstanding under the Stingray Credit Agreement bearing interest at an average floating rate of 6.5% per annum. On the earlier to occur of March 31, 2003 or the accelerated due date pursuant to the Stingray Credit Agreement, if Stingray has not settled all amounts due under the Stingray Credit Agreement, Leviathan is obligated to pay the lesser of (i) $8,500,000, (ii) the aggregate amount of distributions received by Leviathan from Stingray subsequent to January 1, 1998, or (iii) 50% of any then outstanding amounts due pursuant to the Stingray Credit Agreement. Management cannot determine the likelihood of Leviathan's potential obligation associated with the Stingray Credit Agreement.

Hedging Activities

Leviathan hedges a portion of its oil and natural gas production to reduce Leviathan's exposure to fluctuations in market prices of oil and natural gas and to meet certain requirements of the Leviathan Credit Facility. Leviathan uses commodity price swap instruments whereby monthly settlements are based on differences between the prices specified in the instruments and the settlement prices of certain futures contracts quoted on the New York Mercantile Exchange ("NYMEX") or certain other indices. Leviathan settles the instruments by paying the negative difference or receiving the positive difference between the applicable settlement price and the price specified in the contract. The instruments utilized by Leviathan differ from futures contracts in that there is no contractual obligation which requires or allows for the future delivery of the product. The credit risk from Leviathan's price swap contracts is derived from the counter-party to the transaction, typically a major financial institution. Management does not require collateral and does not anticipate non-performance by this counter-party, which does not transact a sufficient volume of transactions with Leviathan to create a significant concentration of credit risk. Gains or losses on hedging activities are recognized as oil and gas sales in the period in which the hedged production is sold. For the years ended December 31, 1998, 1997 and 1996, Leviathan recorded a net (gain) loss of ($2,526,000), $6,340,000 and $2,826,000, respectively, from such activities.

As of December 31, 1998, Leviathan had open sales swap transactions for calendar 1999 of 10,000 million British thermal units ("MMbtu") of natural gas per day at a fixed price to be determined at Leviathan's option equal to the February 1999 Natural Gas Futures Contract on NYMEX as quoted at any time during 1998 and January 1999, to and including the last two trading days of the February 1999 contract, minus $0.23 per MMbtu. In January 1999, Leviathan renegotiated this contract to provide for 10,000 MMbtu of natural gas per day for calendar 2000 at a fixed price to be determined at Leviathan's option equal to the February 2000 Natural Gas Futures Contract on NYMEX as quoted at any time during 1999 and January 2000, to and including the last two trading days of the February 2000 contract, minus $0.5450 per MMbtu.

Additionally, Leviathan had open sales swap transactions for calendar 2000 of 10,000 MMbtu of natural gas per day at a fixed price to be determined at Leviathan's option equal to the January 2000 Natural Gas Futures Contract on NYMEX as quoted at any time during 1999, to and including the last two trading days of the January 2000 contract minus, $0.50 per MMbtu.

If Leviathan had settled its open natural gas hedging positions as of December 31, 1998 and 1997 based on the applicable settlement prices of the NYMEX futures contracts, Leviathan would have recognized a loss (gain) of approximately $2.6 million and ($2.2 million), respectively.

Other

Leviathan is involved from time to time in various claims, actions, lawsuits and regulatory matters that have arisen in the ordinary course of business, including various rate cases and other proceedings before the FERC.

Leviathan and several subsidiaries of El Paso have been made defendants in United States ex rel Grynberg v. El Paso Natural Gas Company, et al. litigation. Generally, the complaint in this motion alleges an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Indian lands, thereby depriving the United States government of royalties. The complaint remains sealed. Leviathan and El Paso believe the complaint is without merit and therefore will not have a material adverse effect on the consolidated financial position, operations or cash flows of Leviathan.

Leviathan is a defendant in a lawsuit filed by Transco Gas Pipe Line Corporation ("Transco") in the 157th Judicial District Court, Harris County, Texas on August 30, 1996. Transco alleges that, pursuant to a platform lease agreement entered into on June 28, 1994, Transco has the right to expand its facilities and operations on the offshore platform by connecting additional pipeline receiving and appurtenant facilities. Management has denied Transco's request to expand its facilities and operations because the lease agreement does not provide for such expansion and because Transco's activities will interfere with the Manta Ray Offshore system and Leviathan's existing and planned activities on the platform. Transco has requested a declaratory judgment and is seeking damages. The case is set for trial in June 1999. It is the opinion of management that adequate defenses exist and that the final disposition of this suit individually, and all of Leviathan's other pending legal proceedings in the aggregate, will not have a material adverse effect on the consolidated financial position, operations or cash flows of Leviathan.

In the ordinary course of business, Leviathan is subject to various laws and regulations. In the opinion of management, compliance with existing laws and regulations will not materially affect the consolidated financial position, operations or cash flows of Leviathan. Various legal actions which have arisen in the ordinary course of business are pending with respect to the pipeline interests and other assets of Leviathan. Management believes that the ultimate disposition of these actions, either individually or in the aggregate, will not have a material adverse effect on the consolidated financial position, operations or cash flows of Leviathan.

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

NOTE 11 -- SUPPLEMENTAL DISCLOSURES TO THE STATEMENT OF CASH FLOWS:

Cash paid, net of amounts capitalized, during each of the periods presented

	YEAR ENDED DECEMBER 31,		
	1998	1997	1996
	(In thousands)		
Interest	$17,608	$12,965	$2,890
Taxes	$ --	$ 11	$ 20

Supplemental disclosures of noncash investing and financing activities

	YEAR ENDED DECEMBER 31,		
	1998	1997	1996
	(In thousands)		
Decrease (increase) in investment in Tatham Offshore	$ 7,500	$ --	$(7,500)
Additions to oil and natural gas properties	(4,683)	--	--
Additions to platform and facilities	(7,024)	--	--
Assumption of abandonment obligations	4,033	--	--
Increase in other noncurrent receivable	--	--	(7,500)
Increase in deferred revenue	--	--	15,000
Conveyance of assets and liabilities to POPCO	--	--	29,758
Conveyance of assets and liabilities to Manta Ray Offshore and Nautilus	30	72,080	--

NOTE 12 -- MAJOR CUSTOMERS:

As discussed in Note 8, Leviathan sells substantially all of its oil and natural gas production to Offshore Marketing.

The percentage of gathering, transportation and platform services revenue from major customers was as follows:

	YEAR ENDED DECEMBER 31,		
	1998	1997	1996
	(In thousands)		
Kerr-McGee Corporation	32%	--	--
Texaco Gas Marketing, Inc	10%	13%	--
Viosca Knoll	13%	--	--
Walter Oil & Gas Corporation	7%	13%	--
Shell Gas Trading Company	--	--	17%
Tatham Offshore	--	--	30%

NOTE 13 -- BUSINESS SEGMENT INFORMATION:

Leviathan's operations consist of three segments: (i) gathering, transportation and platform services, (ii) oil and natural gas and (iii) equity investments. All of Leviathan's operations are conducted in the Gulf. The gathering, transportation and platform services segment owns interests in natural gas systems and platforms strategically located offshore Texas, Louisiana and Mississippi that provides services to producers, marketers, other pipelines and end-users for a fee. Leviathan is engaged in the development and production of hydrocarbons through its oil and natural gas segment (Note 4). Equity investments primarily include Leviathan's nonregulated and regulated gathering and transportation activities that are conducted through joint ventures, organized as general partnerships or limited liability companies, with subsidiaries of major energy companies. The operational and administrative activities of Leviathan's equity investments are primarily conducted by the major energy companies and management decisions related to the operations are made by management committees comprised of representatives of each partner or member, as applicable, with authority appointed in direct relationship to ownership interests (Note 3). Leviathan evaluates segment performance based on operating net cash flows. The accounting policies of the individual segments are the same as those of Leviathan, as a whole, as described in Note 2. The following table summarizes certain financial information for each business segment (in thousands):

	GATHERING, TRANSPORTATION AND PLATFORM SERVICES	OIL AND NATURAL GAS	EQUITY INVESTMENTS	SUBTOTAL	INTERSEGMENT ELIMINATIONS	TOTAL
YEAR ENDED DECEMBER 31, 1998:						
Revenue from external customers...	$ 17,320	$ 31,411	$26,724	$ 75,455	$ --	$ 75,455
Intersegment revenue..............	10,673	--	--	10,673	(10,673)	--
Depreciation, depletion and amortization....................	(7,134)	(22,133)	--	(29,267)	--	(29,267)
Impairment, abandonment and other...........................	1,131	--	--	1,131	--	1,131
Operating income (loss)...........	9,128	(10,271)	20,904	19,761	--	19,761
YEAR ENDED DECEMBER 31, 1997:						
Revenue from external customers...	$ 17,329	$ 58,106	$29,327	$104,762	$ --	$104,762
Intersegment revenue..............	11,162	--	--	11,162	(11,162)	--
Depreciation, depletion and amortization....................	(9,900)	(36,389)	--	(46,289)	--	(46,289)
Impairment, abandonment and other...........................	(10,268)	(10,954)	--	(21,222)	--	(21,222)
Operating income (loss)...........	(1,278)	(9,676)	22,192	11,238	--	11,238
YEAR ENDED DECEMBER 31, 1996:						
Revenue from external customers...	$ 24,005	$ 47,068	$20,434	$ 91,507	$ --	$ 91,507
Intersegment revenue..............	10,052	--	--	10,052	(10,052)	--
Depreciation, depletion and amortization....................	(15,002)	(16,729)	--	(31,731)	--	(31,731)
Operating income..................	9,787	15,489	16,892	42,168	--	42,168

NOTE 14 -- SUBSEQUENT EVENTS:

Acquisition of Additional Interest in Viosca Knoll Gathering Company, the Issuance of Common Units to the General Partner and the Amendment to the Partnership Agreement

Currently, Viosca Knoll is effectively owned 50% by Leviathan and 50% by El Paso (Note 3). In January 1999, Leviathan announced its intent to acquire all of El Paso's interest in Viosca Knoll, other than a 1% interest in profits and capital of Viosca Knoll, for approximately $85.26 million (subject to adjustment), comprised of 25% cash (up to a maximum of $21.315 million) and 75% Common Units (up to a maximum of 3,205,263 Common Units), the number of which will depend on the average closing price of Common Units during the applicable trading reference period. At the closing, (i) El Paso will contribute to Viosca Knoll an amount of money equal to 50% of the amount then outstanding under the Viosca Knoll Credit Facility (currently a total of $66.7 million is outstanding), (ii) Leviathan will deliver to El Paso the cash and Common Units discussed above and (iii) as required by the Partnership Agreement, the General Partner will contribute approximately $650,000 to Leviathan in order to maintain its 1% capital account balance. Then, during the six month period commencing on the day after the first anniversary of that closing date, Leviathan would have the option to acquire the remaining 1% in profits and capital in Viosca Knoll for a cash payment equal to the sum of $1.74 million plus the amount of additional distributions which would have been paid, accrued or been in arrears had Leviathan acquired the remaining 1% of Viosca Knoll at the initial closing by issuing additional Common Units in lieu of a cash payment of $1.74 million.

The number of units actually issued by Leviathan will vary depending on the market price of Common Units during the applicable trading reference period. Such number will be determined by dividing $63.945 million (subject to adjustment) by the average closing sales price for a Common Unit on the NYSE for the ten day trading period ending two days prior to the closing date (the "Market Price"); provided that, for purposes of such calculation, the Market Price will not be less than $19.95 per Common Unit or more than $24.15 per Common Unit. Accordingly, Leviathan will neither issue less than 2,647,826 nor more than 3,205,263 Common Units, subject to adjustments contemplated by the definitive agreements. Based on the closing sales price of the Common Units on March 5, 1999 of $20.875 per unit, Leviathan would issue 3,063,234 Common Units to El Paso, which issuance would constitute approximately 10.9% of the units (Common and Preference) outstanding immediately after such issuance and would result in El Paso owning, indirectly through its subsidiaries, a combined 35.4% effective interest in Leviathan, consisting of a 1% general partnership interest, a 33.4% limited partnership interest comprised of 9,355,128 Common Units and an approximate 1% nonmanaging interest in certain subsidiaries of Leviathan.

Although certain federal and state securities laws would otherwise limit El Paso's ability to dispose of any Common Units held by it, El Paso would have the right on three occasions to require Leviathan to file a registration statement covering such Common Units and to participate in offerings made pursuant to certain other registration statements filed by Leviathan during a ten year period. Such registrations would be at Leviathan's expense and, generally, would allow El Paso to dispose of all or any of its Common Units. If the acquisition is consummated, there can be no assurance regarding how long El Paso may hold any of its Common Units or whether El Paso's disposition of a significant number of Common Units in a short period of time would not depress the market price of the Common Units.

Upon consummation of the acquisition, Leviathan would be the beneficial owner of 99% of Viosca Knoll and have the option to acquire the remaining 1% interest. Leviathan and El Paso entered into a Contribution Agreement dated January 22, 1999, which is effective as of January 1, 1999. Consummation of the acquisition is subject to the satisfaction of certain closing conditions, including, among other things, obtaining certain third party consents. The consent of the lenders under the Leviathan Credit Facility and the Viosca Knoll Credit Facility must be obtained prior to consummating this transaction. There can be no assurance that all such required consents will be obtained. Management believes that the acquisition of the Viosca Knoll interest does not require any federal, state or other regulatory approval.

On January 19, 1999, the Board of Directors of the General Partner unanimously approved and ratified and recommended that the unitholders approve and ratify the acquisition of the additional Viosca Knoll interest. Based upon, among other things, a multi-faceted review and analysis of the acquisition, as well as the recommendation for approval and ratification from the Special Committee of independent directors and the fairness opinion of an independent financial advisor, the Board of Directors of the

General Partner believes that the acquisition is fair to and in the best interests of Leviathan and its unitholders. On March 5, 1999, the unitholders of record as of January 28, 1999, held a meeting and ratified and approved (i) the transactions relating to Leviathan's acquisition of El Paso's interest in Viosca Knoll and (ii) an amendment of the Partnership Agreement to decrease the vote required for approval of certain actions, including the removal of the general partner without cause, from 66 2/3% to 55%.

If the remaining conditions to closing are satisfied, including obtaining certain third party consents, management believes that the closing of the acquisition of the Viosca Knoll interest will occur during the second quarter of 1999.

Joint Venture Restructuring and New Pipeline Construction

In December 1998, the partners of High Island Offshore System, a Delaware partnership between Leviathan (40%), subsidiaries of ANR Pipeline Company ("ANR") (40%) and a subsidiary of Natural Gas Pipeline Company ("NGPL") (20%), restructured the joint venture arrangement by (i) creating a holding company, Western Gulf Holdings, L.L.C. ("Western Gulf"), (ii) converting High Island Offshore System, which owns a jurisdictional natural gas pipeline located in the Gulf, into a limited liability company, HIOS and (iii) forming a new limited liability company, East Breaks Gathering Company, L.L.C. ("East Breaks") to construct and operate a non-jurisdictional natural gas pipeline system. Western Gulf, owned 40% by Leviathan, 40% by ANR and 20% by NGPL, owns 100% of each of HIOS and East Breaks.

In February 1999, Western Gulf entered into a $100 million revolving credit facility (the "Western Gulf Credit Facility") with a syndicate of commercial banks to provide funds for the construction of the East Breaks system and for other working capital needs of Western Gulf. The ability of Western Gulf to borrow money under its credit facility is subject to certain customary terms and conditions, including borrowing base limitations. The credit facility is collateralized by substantially all of the material contracts and agreements of East Breaks and Western Gulf including Western Gulf's ownership in HIOS and East Breaks, and matures in February 2004. As of March 10, 1999, Western Gulf had $44.1 million outstanding under its credit facility bearing interest at an average floating rate of 6.4% per annum and $55.9 million of additional funds were available under the credit facility.

The East Breaks system will initially consist of 85 miles of an 18 to 20-inch pipeline and related facilities connecting the Diana/Hoover prospects developed by Exxon Company USA ("Exxon") and BP Amoco Plc ("BP Amoco") in Alaminos Canyon Block 25 in the Gulf, with the HIOS system. The majority of the construction of the East Breaks system will occur in 1999 and the system is anticipated to be in service in late 2000 at an estimated cost of approximately $90 million. East Breaks entered into long-term agreements with Exxon and BP Amoco involving the commitment, gathering and processing of production from the Diana/Hoover prospects. All of the natural gas to be produced from 11 blocks in the East Breaks and Alaminos Canyon areas will be dedicated for transportation services on the HIOS system.

NOTE 15 -- SUPPLEMENTAL OIL AND NATURAL GAS INFORMATION (UNAUDITED):

Oil and natural gas reserves

The following table represents Leviathan's net interest in estimated quantities of developed and undeveloped reserves of crude oil, condensate and natural gas and changes in such quantities at fiscal year end 1998, 1997 and 1996. Estimates of Leviathan's reserves at December 31, 1998, 1997 and 1996 have been made by the independent engineering consulting firm, Netherland, Sewell & Associates, Inc. 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. 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.

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 (BARRELS)	NATURAL GAS (MCF)
	(In thousands)	
Proved reserves -- December 31, 1995	4,323	61,292
Revisions of previous estimates	(734)	(4,823)
Extensions, discoveries and other additions	294	3,832
Production	(421)	(15,787)
Proved reserves -- December 31, 1996	3,462	44,514
Revisions of previous estimates	(542)	5,441
Production	(801)	(19,792)
Proved reserves -- December 31, 1997	2,119	30,163
Revisions of previous estimates	(33)	1,833
Purchase of reserves in place	32	8,212
Production	(540)	(11,324)
Proved reserves -- December 31, 1998	1,578	28,884
Proved developed reserves -- December 31, 1996	3,149	44,075
Proved developed reserves -- December 31, 1997	2,119	28,324
Proved developed reserves -- December 31, 1998	1,578	26,432

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.

Furthermore, Leviathan's wells have only been producing for a short period of time and, accordingly, estimates of future production are based on this limited history. 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 Leviathan's reserves is based upon volumetric calculations.

Future net cash flows

The standardized measure of discounted future net cash flows relating to Leviathan's 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 hedging and other fixed price contracts in effect, to Leviathan's 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, 1998 were $9.80 per barrel of oil and $1.53 per Mcf of gas. Future production and development costs were computed by applying year-end costs to future years. As Leviathan is not a taxable entity, no future income taxes were provided. A prescribed 10% discount factor was applied to the future net cash flows.

In Leviathan's opinion, this standardized measure is not a representative measure of fair market value, and the standardized measure presented for Leviathan's 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.

	DECEMBER 31,		
	1998	1997	1996
	(In thousands)		
Future cash inflows	$ 53,299	$104,192	$206,311
Future production costs	(13,412)	(15,895)	(13,019)
Future development costs	(10,566)	(10,463)	(5,328)
Future income tax expenses	--	--	--
Future net cash flows	29,321	77,834	187,964
Annual discount at 10% rate	(2,649)	(10,468)	(32,326)
Standardized measure of discounted future net cash flows	$ 26,672	$ 67,366	$155,638

	DECEMBER 31, 1998		
	PROVED DEVELOPED	PROVED UNDEVELOPED	TOTAL
	(In thousands)		
Undiscounted estimated future net cash flows from proved reserves before income taxes	$28,457	$864	$29,321
Present value of estimated future net cash flows from proved reserves before income taxes, discounted at 10%	$26,131	$541	$26,672

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

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

	1998	1997	1996
Beginning of year	$ 67,366	$155,638	$115,170
Sales and transfers of oil and natural gas produced, net of production costs	(22,131)	(53,492)	(40,420)
Net changes in prices and production costs	(32,129)	(35,645)	45,358
Extensions, discoveries and improved recovery, less related costs	--	--	17,077
Oil and natural gas development costs incurred during the year	120	11,140	57,501
Changes in estimated future development costs	(443)	(12,439)	(29,421)
Revisions of previous quantity estimates	1,920	(3,817)	(19,686)
Purchase of reserves in place	7,573	--	--
Accretion of discount	6,736	15,564	11,517
Changes in production rates, timing and other	(2,340)	(9,583)	(1,458)
End of year	$ 26,672	$ 67,366	$155,638

NOTE 16 -- SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	YEAR 1998				
	QUARTER ENDED				
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31	YEAR
	(In thousands, except for per Unit data)				
Revenue	$17,714	$18,373	$18,230	$21,138	$75,455
Gross profit(a)	$ 7,010	$ 8,687	$ 8,165	$10,957	$34,819
Net income (loss)	$(1,424)	$ 1,510	$(1,806)	$ 2,466	$ 746
Basic and diluted net income (loss) per unit	$ (0.05)	$ 0.05	$ (0.06)	$ 0.08	$ 0.02
Weighted average number of Units outstanding	24,367	24,367	24,367	24,367	24,367
Distributions declared per Common Unit	$ 0.525	$ 0.525	$ 0.525	$ 0.525	$ 2.10
Distributions declared per Preference Unit	$ 0.525	$ 0.525	$ 0.275	$ 0.275	$ 1.60

	YEAR 1997				
	QUARTER ENDED				
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31	YEAR
	(In thousands, except for per Unit data)				
Revenue	$31,028	$ 28,226	$25,474	$20,034	$104,762
Gross profit(a)	$13,980	$ 11,289	$11,311	$10,541	$ 47,121
Net income (loss)	$ 8,964	$(15,855)	$ 3,274	$ 2,479	$ (1,138)
Basic and diluted net income (loss) per unit	$ 0.32	$ (0.58)	$ 0.12	$ 0.08	$ (0.06)
Weighted average number of Units outstanding	24,367	24,367	24,367	24,367	24,367
Distributions declared per Preference and Common Unit	$ 0.425	$ 0.45	$ 0.475	$ 0.50	$ 1.85

	YEAR 1996				
	QUARTER ENDED				
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31	YEAR
	(In thousands, except for per Unit data)				
Revenue	$19,637	$18,562	$24,214	$29,094	$91,507
Gross profit(a)	$12,437	$10,792	$13,246	$14,233	$50,708
Net income (loss)	$10,910	$ 9,161	$10,006	$ 8,615	$38,692
Basic and diluted net income (loss) per unit	$ 0.44	$ 0.37	$ 0.41	$ 0.35	$ 1.57
Weighted average number of Units outstanding	24,367	24,367	24,367	24,367	24,367
Distributions declared per Preference and Common Unit	$ 0.325	$ 0.35	$ 0.375	$ 0.40	$ 1.45

(a) Represent revenue less operating and depreciation, depletion and amortization expenses.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholder of
Leviathan Finance Corporation

In our opinion, the accompanying balance sheet presents fairly, in all material respects, the financial position of Leviathan Finance Corporation (the "Company") at April 30, 1999 in conformity with generally accepted accounting principles. This financial statement is the responsibility of the Company's management; our responsibility is to express an opinion on this financial statement based on our audit. We conducted our audit of this statement in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statement is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statement, 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 the opinion expressed above.

PricewaterhouseCoopers LLP

Houston, Texas
May 3, 1999

LEVIATHAN FINANCE CORPORATION
(A WHOLLY OWNED SUBSIDIARY OF LEVIATHAN GAS PIPELINE PARTNERS, L.P.)

BALANCE SHEET

APRIL 30, 1999

ASSETS	
Subscription receivable from parent	$1,000
Total assets	$1,000
STOCKHOLDER'S EQUITY	
Common stock, $1.00 par value, 1,000 shares authorized; 1,000 issued and outstanding	$1,000
Total stockholder's equity	$1,000

The accompanying note is an integral part of this financial statement.

LEVIATHAN FINANCE CORPORATION
(A WHOLLY OWNED SUBSIDIARY OF LEVIATHAN GAS PIPELINE PARTNERS, L.P.)

NOTE TO BALANCE SHEET

NOTE 1 -- ORGANIZATION:

Leviathan Finance Corporation (the "Company"), a Delaware corporation, was formed on April 30, 1999 for the sole purpose of co-issuing $175,000,000 aggregate principal amount of Senior Subordinated Notes due May 2009 (the "Notes") with Leviathan Gas Pipeline Partners, L.P. ("Leviathan"), the Company's parent. Leviathan, a publicly held Delaware master limited partnership, is primarily engaged in the gathering, transportation and production of natural gas and crude oil in the Gulf of Mexico. Through its subsidiaries and joint ventures, Leviathan owns interests in significant assets, including (i) eight natural gas pipelines, (ii) a crude oil pipeline system, (iii) six strategically-located multi-purpose platforms, (iv) a dehydration facility, (v) four producing oil and natural gas properties and (vi) one undeveloped oil and natural gas property.

The Company's subscription receivable was generated from the initial capitalization of the Company in which the Company issued 1,000 shares of common stock at $1.00 par value. The Company has not conducted any operations and all activities have related to the issuance of the Notes.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Partners of Viosca Knoll Gathering
Company (a Delaware general partnership)

In our opinion, the accompanying balance sheet and the related statements of operations, of cash flows and of partners' capital present fairly, in all material respects, the financial position of Viosca Knoll Gathering Company (a Delaware general partnership) ("Viosca Knoll") as of December 31, 1998 and 1997, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1998 in conformity with generally accepted accounting principles. These financial statements are the responsibility of Viosca Knoll's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with generally accepted auditing standards 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 the opinion expressed above.

PricewaterhouseCoopers LLP

Houston, Texas
March 19, 1999

VIOSCA KNOLL GATHERING COMPANY
(A DELAWARE GENERAL PARTNERSHIP)

BALANCE SHEET
(In thousands)

	JUNE 30, 1999 (UNAUDITED)	DECEMBER 31, 1998	DECEMBER 31, 1997
ASSETS			
Current assets:			
Cash and cash equivalents	$ 182	$ 155	$ 135
Accounts receivable	3,068	4,885	2,658
Accounts receivable from affiliates	1,590	179	561
Other current assets	232	232	--
Total current assets	5,072	5,451	3,354
Property and equipment:			
Pipelines	145,652	108,121	103,121
Construction-in-progress	67	--	1,449
Other	77	77	24
	145,796	108,198	104,594
Less: Accumulated depreciation	12,811	10,662	6,886
Property, plant and equipment, net	132,985	97,536	97,708
Debt issue costs, net	--	222	296
Total assets	$138,057	$103,209	$101,358
LIABILITIES AND PARTNERS' CAPITAL			
Current liabilities:			
Accounts payable	$ 27	$ 414	$ 3,841
Accounts payable to affiliates	155	552	851
Accrued liabilities	5,102	55	6,588
Total current liabilities	5,284	1,021	11,280
Provision for negative salvage	382	340	256
Notes payable	--	66,700	52,200
	5,666	68,061	63,736
Commitments and contingencies (Note 5)			
Partners' capital:			
VK Deepwater	131,389	17,574	18,811
EPEC Deepwater	1,002	17,574	18,811
	132,391	35,148	37,622
Total liabilities and partners' capital	$138,057	$103,209	$101,358

The accompanying notes are an integral part of this financial statement.

VIOSCA KNOLL GATHERING COMPANY
(A DELAWARE GENERAL PARTNERSHIP)

STATEMENT OF OPERATIONS
(In thousands)

	SIX MONTHS ENDED JUNE 30,		YEAR ENDED DECEMBER 31,		
	1999	1998	1998	1997	1996
	(UNAUDITED)				
Revenue:					
Transportation services	$14,743	$14,314	$28,806	$23,128	$13,923
Oil and natural gas sales	49	432	528	--	--
	14,792	14,746	29,334	23,128	13,923
Costs and expenses:					
Operating expenses	1,129	1,181	2,877	1,990	298
Depreciation	2,191	1,893	3,860	2,474	2,269
General and administrative expenses	71	82	154	125	126
	3,391	3,156	6,891	4,589	2,693
Operating income	11,401	11,590	22,443	18,539	11,230
Interest income	33	23	50	40	--
Interest and other financing costs	(1,973)	(1,989)	(4,267)	(1,959)	(90)
Net income	$ 9,461	$ 9,624	$18,226	$16,620	$11,140

The accompanying notes are an integral part of this financial statement.

VIOSCA KNOLL GATHERING COMPANY
(A DELAWARE GENERAL PARTNERSHIP)

STATEMENT OF CASH FLOWS
(In thousands)

	SIX MONTHS ENDED JUNE 30, 1999	1998	YEAR ENDED DECEMBER 31, 1998	1997	1996
	(UNAUDITED)				
Cash flows from operating activities:					
Net income	$ 9,461	$ 9,624	$ 18,226	$ 16,620	$ 11,140
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation	2,191	1,893	3,860	2,474	2,269
Amortization of debt issue costs	222	37	74	73	--
Changes in operating working capital:					
Decrease (increase) in accounts receivable	1,817	(496)	(2,227)	340	(1,462)
(Increase) decrease in accounts receivable from affiliates	(1,411)	546	382	573	(1,046)
Increase in other current assets	--	--	(232)	--	--
(Decrease) increase in accounts payable	(387)	(3,572)	(3,427)	1,937	1,557
(Decrease) increase in accounts payable to affiliates	(397)	(498)	(299)	513	(2,312)
Decrease (increase) in accrued liabilities	(53)	(6,538)	(6,533)	6,328	(251)
Net cash provided by operating activities	11,443	996	9,824	28,858	9,895
Cash flows from investing activities:					
Additions to pipeline assets	(49)	(1,179)	(3,604)	(27,541)	(5,219)
Construction-in-progress	(67)	--	--	(1,449)	(3,410)
Net cash used in investing activities	(116)	(1,179)	(3,604)	(28,990)	(8,629)
Cash flows from financing activities:					
Proceeds from notes payable	--	11,800	14,500	18,900	33,300
Repayment of notes payable	(66,700)	--	--	--	--
Contributions from partners	68,100	--	--	320	3,018
Distributions to partners	(12,700)	(11,600)	(20,700)	(19,300)	(36,900)
Debt issue costs	--	--	--	(70)	(300)
Net cash (used in) provided by financing activities	(11,300)	200	(6,200)	(150)	(882)
Net increase (decrease) in cash and cash equivalents	27	17	20	(282)	384
Cash and cash equivalents at beginning of year	155	135	135	417	33
Cash and cash equivalents at end of period	$ 182	$ 152	$ 155	$ 135	$ 417
Cash paid for interest, net of amounts capitalized	$ 1,804	$ 1,943	$ 4,180	$ 1,878	$ --
Noncash investing activities:					
Additions to pipeline assets offset by additions to accrued liabilities	$ 5,100	$ --	$ --	$ --	$ --

The accompanying notes are an integral part of this financial statement.

VIOSCA KNOLL GATHERING COMPANY
(A DELAWARE GENERAL PARTNERSHIP)

STATEMENT OF PARTNERS' CAPITAL
(In thousands)

	VK DEEPWATER	EPEC DEEPWATER	TOTAL
Partners' capital at December 31, 1995	$ 31,362	$ 31,362	$ 62,724
Contributions	1,509	1,509	3,018
Distributions	(18,450)	(18,450)	(36,900)
Net income	5,570	5,570	11,140
Partners' capital at December 31, 1996	19,991	19,991	39,982
Contributions	160	160	320
Distributions	(9,650)	(9,650)	(19,300)
Net income	8,310	8,310	16,620
Partners' capital at December 31, 1997	18,811	18,811	37,622
Distributions	(10,350)	(10,350)	(20,700)
Net income	9,113	9,113	18,226
Partners' capital at December 31, 1998	17,574	17,574	35,148
Contributions (unaudited)	34,050	34,050	68,100
Distributions (unaudited)	(6,350)	(6,350)	(12,700)
Transfer ownership interest (unaudited) (Note 9)	48,151	(48,151)	--
Capital contribution related to acquisition of 49% interest (unaudited) (Note 9)	32,382	--	32,382
Net income (unaudited)	5,582	3,879	9,461
Partners' capital at June 30, 1999 (unaudited)	$ 131,389	$ 1,002	$ 132,391

The accompanying notes are an integral part of this financial statement.

VIOSCA KNOLL GATHERING COMPANY
(A DELAWARE GENERAL PARTNERSHIP)

NOTES TO FINANCIAL STATEMENTS

NOTE 1 -- ORGANIZATION:

Viosca Knoll Gathering Company ("Viosca Knoll") is a Delaware general partnership formed in May 1994 to design, construct, own and operate the Viosca Knoll Gathering System (the "Viosca Knoll system") and any additional facilities constructed or acquired pursuant to the Joint Venture Agreement between VK Deepwater Gathering Company, L.L.C. ("VK Deepwater"), an approximate 99% owned subsidiary of Leviathan Gas Pipeline Partners, L.P. ("Leviathan"), and EPEC Deepwater Gathering Company ("EPEC Deepwater"), an indirect subsidiary of El Paso Energy Corporation ("El Paso"). El Paso, as a result of its merger with DeepTech International Inc. on August 14, 1998, owns an effective 27.3% interest in Leviathan. Each of the partners has a 50% interest in Viosca Knoll. Viosca Knoll is managed by a committee consisting of representatives from each of the partners. Viosca Knoll has no employees. VK Deepwater is the operator of Viosca Knoll and has contracted with an affiliate of EPEC Deepwater to maintain the pipeline and with Leviathan to perform financial, accounting and administrative services.

The Viosca Knoll system is a non-jurisdictional gathering system designed to serve the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico (the "Gulf"), southeast of New Orleans, offshore Louisiana. The Viosca Knoll system, has a maximum design capacity of approximately 1 billion cubic feet of natural gas per day and consists of 125 miles of predominantly 20-inch natural gas pipelines and a large compressor. The Viosca Knoll system provides its customers access to the facilities of a number of major interstate pipelines, including Tennessee Gas Pipeline Company, Columbia Gulf Transmission Company, Southern Natural Gas Company, Transcontinental Gas Pipe Line and Destin Pipeline Company.

The base system, comprised of (i) an approximately 94 mile, 20-inch diameter pipeline from a platform in Main Pass Block 252 owned by Shell Offshore, Inc. ("Shell") to a pipeline owned by Tennessee Gas Pipeline Company at South Pass Block 55 and (ii) a six mile, 16-inch diameter pipeline from an interconnection with the 20-inch diameter pipeline at Viosca Knoll Block 817 to a pipeline owned by Southern Natural Gas Company at Main Pass Block 289, was constructed in 1994. A 7,000 horsepower compressor was installed in 1996 on Leviathan's Viosca Knoll 817 platform to allow Viosca Knoll to effect deliveries at the operating pressures on downstream interstate pipelines with which it is interconnected. The additional capacity created by such compression allowed Viosca Knoll to transport new natural gas volumes during 1997 from the Shell-operated Southeast Tahoe and Ram-Powell fields as well as other new deepwater projects in the area. In 1997, Viosca Knoll added approximately 25 miles of parallel 20-inch pipelines.

NOTE 2 -- SIGNIFICANT ACCOUNTING POLICIES:

Cash and cash equivalents

All highly liquid investments with a maturity of three months or less when purchased are considered to be cash equivalents.

Property and equipment

Gathering pipelines and related facilities are recorded at cost and depreciated on a straight-line basis over an estimated useful life of 30 years. Viosca Knoll also calculates a negative salvage provision using the straight-line method based on an estimated cost of abandoning the pipeline of $2.5 million. Other property, plant and equipment is depreciated on a straight-line basis over an estimated useful life of five years. Maintenance and repair costs are expensed as incurred; additions, improvements and replacements are capitalized. Retirements, sales and disposals of assets are recorded by eliminating the related costs and accumulated depreciation of the disposed assets with any resulting gain or loss reflected in income.

Viosca Knoll evaluates impairment of its property and equipment in accordance with Statement of Financial Accounting Standard ("SFAS") No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" which requires recognition of impairment losses on long-lived assets if the carrying amount of such assets, grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows from other assets, exceeds the estimated undiscounted future cash flows of such assets. Measurement of any impairment loss will be based on the fair value of the assets.

Capitalization of interest

Interest and other financing costs are capitalized in connection with construction 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. Any unamortized debt issue costs are expensed at the time the related indebtedness is repaid or otherwise terminated.

Revenue recognition

Revenue from pipeline transportation of natural gas is recognized upon receipt of the natural gas into the pipeline system. Revenue from demand charges is recognized in the period the services are provided. Revenue from oil and natural gas sales is recognized upon delivery in the period of production.

Income taxes

Viosca Knoll is not a taxable entity. Income taxes are the responsibility of the partners and are not reflected in these financial statements. However, the taxable income or loss resulting from the operations of Viosca Knoll will ultimately be included in the federal income tax returns of the partners and may vary substantially from income or loss reported for financial statement purposes.

Estimates

The preparation of Viosca Knoll's financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions, including those related to potential environmental liabilities and future regulatory status, that affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Management believes that the estimates are reasonable.

Recent Pronouncements

In April 1998, the American Institute of Certified Public Accountants issued SOP 98-5, "Reporting on the Costs of Start-Up Activities." This statement defines start-up activities, requires start-up and organization costs to be expensed as incurred and requires that any such costs that exist on the balance sheet be expensed upon adoption of this pronouncement. The statement is effective for fiscal years beginning after December 15, 1998. Viosca Knoll adopted the provisions of this statement on January 1, 1999 resulting in no material impact on its financial position or results of operations.

VIOSCA KNOLL GATHERING COMPANY
(A DELAWARE GENERAL PARTNERSHIP)

NOTES TO FINANCIAL STATEMENTS -- (CONTINUED)

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, as amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities," to be effective for all fiscal years beginning after June 15, 2000. SFAS No. 133, as amended, requires that entities recognize all derivative instruments as either assets or liabilities on the balance sheet and measure those instruments at fair value. The accounting for changes in the fair value of a derivative will depend on the intended use of the derivative and the resulting designation. Viosca Knoll is currently evaluating the impact, if any, of SFAS No. 133, as amended.

NOTE 3 -- INDEBTEDNESS:

In December 1996, Viosca Knoll entered into a revolving credit facility (the "Viosca Knoll Credit Facility") with a syndicate of commercial banks to provide up to $100 million for the addition of compression and expansion to the Viosca Knoll System and for other working capital needs of Viosca Knoll, including providing a one time distribution not to exceed $25 million to its partners (Note 7). Viosca Knoll's ability to borrow money under the facility is subject to certain customary terms and conditions, including borrowing base limitations. The Viosca Knoll Credit Facility is collateralized by all of Viosca Knoll's material contracts and agreements, receivables and inventory and matures on December 20, 2001. As of December 31, 1998 and 1997, Viosca Knoll had $66,700,000 and $52,200,000, respectively, outstanding under the Viosca Knoll Credit Facility bearing interest at an average floating rate of 6.7% per annum. As of December 31, 1998, approximately $33,300,000 of additional funds were available under the Viosca Knoll Credit Facility. See Note 8.

Interest and other financing costs totaled $1,973,000 (unaudited), $4,278,000, $2,710,000 and $90,000 for the six months ended June 30, 1999 and for the years ended December 31, 1998, 1997 and 1996, respectively. During the six months ended June 30, 1999 and the years ended December 31, 1998 and 1997, Viosca Knoll capitalized $0 (unaudited), $11,000 and $751,000, respectively, of such costs in connection with construction projects in progress.

NOTE 4 -- RELATED PARTY TRANSACTIONS:

Pursuant to a management agreement dated May 24, 1994 between Viosca Knoll and Leviathan, Leviathan charges Viosca Knoll a base fee of $100,000 annually in exchange for Leviathan providing financial, accounting and administrative services on behalf of Viosca Knoll. For each of the years ended December 31, 1998, 1997 and 1996, Leviathan charged Viosca Knoll $100,000 in accordance with this management agreement.

Viosca Knoll and EPEC Gas Services Company ("EPEC Gas"), an affiliate of EPEC Deepwater, entered into a construction and operation agreement whereby EPEC Gas provided personnel to manage the construction and operation of the Viosca Knoll System in exchange for a one-time management fee of $3,000,000 and provides routine maintenance services on behalf of Viosca Knoll. For the years ended December 31, 1998, 1997 and 1996, EPEC Gas charged Viosca Knoll $415,000, $216,000 and $200,000, respectively, with respect to its operating and maintenance services.

In addition, EPEC Gas and VK-Main Pass Gathering Company, L.L.C. ("VK Main Pass"), a subsidiary of Leviathan, acquired and installed a compressor on the Viosca Knoll 817 Platform, which is owned by Leviathan. The compressor was placed in service in January 1997. For the years ended December 31, 1998, 1997 and 1996, Viosca Knoll reimbursed EPEC Gas $1,762,000, $1,282,000 and $8,072,000, respectively, for construction related costs. For the years ended December 31, 1998, 1997 and 1996, Viosca Knoll reimbursed VK Main Pass $152,000, $47,000 and $254,000, respectively, for construction related items.

VIOSCA KNOLL GATHERING COMPANY
(A DELAWARE GENERAL PARTNERSHIP)

NOTES TO FINANCIAL STATEMENTS -- (CONTINUED)

Included in transportation services revenue during the years ended December 31, 1998, 1997 and 1996 is $1,881,000, $3,921,000 and $3,229,000, respectively, of revenue earned from transportation services provided to Flextrend Development Company, L.L.C., a subsidiary of Leviathan. Included in operating expenses for the years ended December 31, 1998, 1997 and 1996 is $2,447,000, $2,116,000 and $249,000, respectively, of platform access fees and related expenses charged to Viosca Knoll by VK Main Pass.

NOTE 5 -- COMMITMENTS AND CONTINGENCIES:

In the ordinary course of business, Viosca Knoll is subject to various laws and regulations. In the opinion of management, compliance with existing laws and regulations will not materially affect the financial position or operations of Viosca Knoll.

The Viosca Knoll system is a gathering facility and as such is not currently subject to rate and certificate regulation by the Federal Energy Regulatory Commission (the "FERC"). However, the FERC has asserted that it has rate jurisdiction under the Natural Gas Act of 1938, as amended (the "NGA"), over gathering services performed through gathering facilities owned by a natural gas company (as defined in the NGA) when such services were performed "in connection with" transportation services provided by such natural gas company. Whether, and to what extent, the FERC should exercise any NGA rate jurisdiction it may be found to have over gathering facilities owned either by natural gas companies or affiliates thereof is subject to case-by-case review by the FERC. Based on current FERC policy and precedent, Viosca Knoll does not anticipate that the FERC will assert or exercise any NGA rate jurisdiction over the Viosca Knoll system so long as the services provided through such system are not performed "in connection with" transportation services performed through any of the regulated pipelines of either of the partners.

NOTE 6 -- MAJOR CUSTOMERS:

Transportation revenue from major customers was as follows:

	YEAR ENDED DECEMBER 31,					
	1998		1997		1996	
	AMOUNT	%	AMOUNT	%	AMOUNT	%
Shell Offshore, Inc.	$10,836	38	$11,198	48	$ 5,141	37
Snyder Oil Corporation	4,801	17	3,653	16	3,275	24
Exxon Corporation	3,354	12	498	2	--	--
Amoco Production Company	3,292	11	475	2	--	--
Flextrend Development Company, L.L.C.	1,881	7	3,921	17	3,229	23
Other	4,642	15	3,383	15	2,278	16
	$28,806	100	$23,128	100	$13,923	100

NOTE 7 -- CASH DISTRIBUTIONS:

In March 1995, Viosca Knoll began making monthly distributions of 100% of its Available Cash, as defined in the Joint Venture Agreement, to the partners. Available Cash consists generally of all the cash receipts of Viosca Knoll less all of its cash disbursements less reasonable reserves, including, without limitation, those necessary for working capital and near-term commitments and obligations or other contingencies of Viosca Knoll. Viosca Knoll expects to make distributions of Available Cash within 15 days after the end of each month to its partners. During the six months ended June 30, 1999 and the years ended December 31, 1998, 1997 and 1996, Viosca Knoll paid distributions of $12,700,000 (unaudited), $20,700,000, $19,300,000 and $36,900,000, respectively, to its partners. The distributions paid

VIOSCA KNOLL GATHERING COMPANY
(A DELAWARE GENERAL PARTNERSHIP)

NOTES TO FINANCIAL STATEMENTS -- (CONTINUED)

during 1996 include $25 million of funds provided from borrowings under the Viosca Knoll Credit Facility. The Viosca Knoll Credit Facility Agreement includes a covenant by which distributions are limited to the greater of net income or 90% of earnings before interest and depreciation as defined in the agreement. See Note 8.

NOTE 8 -- RECENT EVENTS:

In January 1999, EPEC Deepwater announced the sale of (a) all of its interest in Viosca Knoll, other than a 1% interest in profits and capital in Viosca Knoll, to VK Deepwater for approximately $85.26 million (subject to adjustment), comprised of 25% cash (up to a maximum of $21.315 million) and 75% common units of Leviathan (up to a maximum of 3,205,263 common units), the actual number of which will depend on the average closing price of the common units during the applicable trading reference period, and (b) an option to acquire the remaining 1% interest in the profits and capital in Viosca Knoll.

Prior to closing, Viosca Knoll must obtain consent from its lenders under the Viosca Knoll Credit Facility and Leviathan must obtain consent from its lenders as well. At such time, either or both of such credit facilities may be restructured.

At the closing, which is anticipated to be during the second quarter of 1999, (i) EPEC Deepwater will contribute to Viosca Knoll an amount of money equal to 50% of the amount then outstanding under the Viosca Knoll Credit Facility (currently a total of $66.7 million is outstanding) and (ii) VK Deepwater, through Leviathan, will pay El Paso and EPEC Deepwater the cash and common units discussed above. Then, during the six month period commencing on the day after the first anniversary of that closing date, VK Deepwater would have the option to acquire the remaining 1% in profits and capital in Viosca Knoll for a cash payment equal to the sum of $1.74 million plus the amount of additional distributions which would have been paid, accrued or been in arrears had VK Deepwater acquired the remaining 1% of Viosca Knoll at the initial closing by issuing additional common units of Leviathan in lieu of a cash payment of $1.74 million.

NOTE 9 -- CONSUMMATION OF VIOSCA KNOLL TRANSACTIONS (UNAUDITED)

On June 1, 1999, VK Deepwater and EPEC Deepwater consummated the Viosca Knoll transactions (See Note 8). In connection therewith, (i) EPEC Deepwater contributed to Viosca Knoll $33.4 million, and (ii) EPEC Deepwater transferred a 49% interest in Viosca Knoll to VK Deepwater in exchange for a cash payment of approximately $19.9 million and the issuance of 2,661,870 common units of Leviathan valued at $59.8 million. The excess of VK Deepwater's cost over the underlying book value of Viosca Knoll's net assets at June 1, 1999 (approximately $32.3 million) has been pushed down to the financial statements of Viosca Knoll as an adjustment to property and equipment and partners' capital. Accordingly, the financial statements as of and for the six months ended June 30, 1999 are not comparable with prior periods.

INDEPENDENT AUDITORS' REPORT

To the Management Committee
High Island Offshore System, L.L.C.
Detroit, Michigan

We have audited the accompanying statements of financial position of High Island Offshore System, L.L.C. as of December 31, 1998 and 1997, and the related statements of income, members' equity, and cash flows for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of the High Island Offshore System, L.L.C.'s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements present fairly, in all material respects, the financial position of High Island Offshore System, L.L.C. as of December 31, 1998 and 1997, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1998 in conformity with generally accepted accounting principles.

DELOITTE & TOUCHE LLP

Detroit, Michigan
February 19, 1999

HIGH ISLAND OFFSHORE SYSTEM, L.L.C.

STATEMENTS OF FINANCIAL POSITION

	AS OF JUNE 30, 1999	AS OF DECEMBER 31, 1998	1997
	(UNAUDITED)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 1,272,342	$ 868,312	$ 876,845
Accounts receivable	5,872,504	3,777,590	4,709,918
Prepayments	234,151	15,948	--
Total current assets	7,378,997	4,661,850	5,586,763
Gas transmission plant	373,121,843	372,370,180	371,321,033
Less -- accumulated depreciation	366,923,035	364,601,970	359,830,332
Net gas transmission plant	6,198,808	7,768,210	11,490,701
Deferred charges	4,205,497	5,168,277	590,189
Total assets	$ 17,783,302	$ 17,598,337	$ 17,667,653
LIABILITIES AND MEMBERS' EQUITY			
Current liabilities:			
Accounts payable	$ 4,763,200	$ 2,424,849	$ 3,077,779
Unamortized rate reductions for excess deferred federal income taxes	50,337	201,347	302,021
Total current liabilities	4,813,537	2,626,196	3,379,800
Noncurrent liabilities			
Unamortized rate reductions for excess deferred federal income taxes	--	--	198,510
Commitments and contingencies (Note 6)	--	--	--
Members' equity	12,969,765	14,972,141	14,089,343
Total liabilities and members' equity	$ 17,783,302	$ 17,598,337	$ 17,667,653

See notes to the financial statements.

HIGH ISLAND OFFSHORE SYSTEM, L.L.C.

STATEMENTS OF INCOME AND STATEMENTS OF MEMBERS' EQUITY

	SIX MONTHS ENDED JUNE 30,		YEAR ENDED DECEMBER 31,		
	1999	1998	1998	1997	1996
	(UNAUDITED)				
STATEMENTS OF INCOME					
Operating revenues:					
Transportation services	$ 19,279,440	$ 21,667,940	$ 43,477,250	$ 45,414,839	$ 47,052,978
Other	188,209	196,280	340,323	502,111	387,764
Total operating revenues	19,467,649	21,864,220	43,817,573	45,916,950	47,440,742
Operating expenses:					
Operation and maintenance	8,540,105	8,521,170	18,935,495	16,975,738	15,548,824
Depreciation	2,321,066	2,384,078	4,771,638	4,773,588	4,775,405
Property taxes	108,854	111,105	111,105	125,368	133,662
Total operating expenses	10,970,025	11,016,353	23,818,238	21,874,694	20,457,891
Net operating income	8,497,624	10,847,867	19,999,335	24,042,256	26,982,851
Other income and deductions	--	--	(16,537)	--	96,624
Total other income and deductions	--	--	(16,537)	--	96,624
Net income	$ 8,497,624	$ 10,847,867	$ 19,982,798	$ 24,042,256	$ 27,079,475
STATEMENTS OF MEMBERS' EQUITY					
Balance at beginning of period	$ 14,972,141	$ 14,089,343	$ 14,089,343	$ 20,547,087	$ 21,967,612
Net income	8,497,624	10,847,867	19,982,798	24,042,256	27,079,475
Capital contributions	--	--	4,000,000	--	--
Distributions to members	(10,500,000)	(13,100,000)	(23,100,000)	(30,500,000)	(28,500,000)
Balance at end of period	$ 12,969,765	$ 11,837,210	$ 14,972,141	$ 14,089,343	$ 20,547,087

See notes to the financial statements.

HIGH ISLAND OFFSHORE SYSTEM, L.L.C.

STATEMENTS OF CASH FLOWS

	SIX MONTHS ENDED JUNE 30, 1999 (UNAUDITED)	SIX MONTHS ENDED JUNE 30, 1998 (UNAUDITED)	YEARS ENDED DECEMBER 31, 1998	YEARS ENDED DECEMBER 31, 1997	YEARS ENDED DECEMBER 31, 1996
Cash flows from operating activities:					
Net income	$ 8,497,624	$ 10,847,867	$ 19,982,798	$ 24,042,256	$ 27,079,475
Adjustments to reconcile net income to cash provided by operating activities					
Depreciation	2,321,066	2,384,078	4,771,638	4,773,588	4,775,405
Accounts receivable	(2,094,914)	948,775	932,328	7,260	(353,633)
Prepayments	(218,203)	--	(15,948)	211,842	91,444
Deferred charges and other	811,770	242,547	(4,877,271)	(145,294)	67,173
Provision for regulatory matters	--	--	--	--	(1,050,623)
Accounts payable	2,753,441	(643,394)	(335,434)	23,821	(1,515,481)
Cash provided by operating activities	12,070,784	13,779,873	20,458,111	28,913,473	29,093,760
Cash flows from investing activities:					
Capital expenditures	(1,166,754)	(20,478)	(1,366,644)	(822,554)	(209,863)
Cash used in investing activities	(1,166,754)	(20,478)	(1,366,644)	(822,554)	(209,863)
Cash flows from financing activities:					
Capital contributions	--	--	4,000,000	--	--
Distributions to members	(10,500,000)	(13,100,000)	(23,100,000)	(30,500,000)	(28,500,000)
Cash used in financing activities	(10,500,000)	(13,100,000)	(19,100,000)	(30,500,000)	(28,500,000)
Increase (decrease) in cash and cash equivalents	404,030	659,395	(8,533)	(2,409,081)	383,897
Cash and cash equivalents at beginning of period	868,312	876,845	876,845	3,285,926	2,902,029
Cash and cash equivalents at end of period	$ 1,272,342	$ 1,536,240	$ 868,312	$ 876,845	$ 3,285,926

See notes to the financial statements.

HIGH ISLAND OFFSHORE SYSTEM, L.L.C.

NOTES TO THE FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 1998, 1997 AND 1996

NOTE 1 -- FORMATION AND OWNERSHIP STRUCTURE

Description and Business Purpose

Effective December 10, 1998, High Island Offshore System, ("HIOS" or the "Company"), a Delaware partnership, was converted to a Delaware Limited Liability Corporation ("L.L.C."). In January 1999, the members of HIOS, each of which owned a 20% interest, contributed their capital accounts to Western Gulf Holdings, L.L.C. ("Western Gulf") in exchange for an equivalent ownership interest in Western Gulf. As a result, Western Gulf now owns a 100% interest in the Company. Western Gulf was formed to invest in the development of a 85 mile pipeline which will connect to HIOS and extend to the deep water "Diana" prospect containing an estimated 1 trillion cubic feet of reserves. The new line is scheduled to begin transporting gas in late 2000 and is projected to cost $90 million. The line will be owned by East Breaks Gathering Company, L.L.C., which is also owned by Western Gulf.

HIOS owns a 203.4 mile undersea gas transmission system in the Gulf of Mexico which provides transportation services as authorized by the Federal Energy Regulatory Commission ("FERC"). HIOS' major transportation customers include natural gas marketers and producers, and interstate natural gas pipeline companies. The Company extends credit for transportation services provided to these customers. The concentrations of customers, described above, may affect the Company's overall credit risk in that the customers may be similarly affected by changes in economic, regulatory and other factors.

HIOS is managed by a committee consisting of representatives from each of the member companies. HIOS has no employees. ANR Pipeline Company ("ANR") operates the system on behalf of HIOS under an agreement which provides that services rendered to HIOS will be reimbursed at cost ($12.4 million for 1998, $11.4 million for 1997, and $9.6 million for 1996).

NOTE 2 -- SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The Company is regulated by the FERC. In addition, the Company meets the criteria and, accordingly, follows the accounting and reporting requirements of Statement of Financial Accounting Standards No. 71 for regulated enterprises.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses. Actual results could differ from those estimates. Management believes that its estimates are reasonable.

Depreciation

Annual depreciation and negative salvage provisions are computed on a straight-line basis using rates of depreciation which vary by type of property. The annual composite depreciation rates were approximately 1.29% for 1998, 1997, and 1996 which include a provision for negative salvage of .2% for offshore facilities.

Income Taxes

For tax filing purposes, the Company has elected partnership status, and therefore, income taxes are the responsibility of the Members and are not reflected in the financial statements of the Company.

HIGH ISLAND OFFSHORE SYSTEM, L.L.C.

NOTES TO THE FINANCIAL STATEMENTS -- (CONTINUED)

Statement of Cash Flows

For purposes of these financial statements, the Company considers short-term investments purchased with an original maturity of three months or less to be cash equivalents. The Company had short-term investments in the amount of $.9 million at December 31, 1998 and 1997. The Company made no cash payments for interest in 1998, 1997, or 1996.

Accounting Pronouncements

The Financial Accounting Standards Board has issued FAS 133, as amended by FAS 137, "Accounting for Derivative Instruments and Hedging Activities," to be effective for all fiscal years beginning after June 15, 2000. FAS 133, as amended, requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. The accounting for changes in the fair value of a derivative will depend on the intended use of the derivative and the resulting designation. The Company is currently evaluating the impact, if any, of FAS 133, as amended.

NOTE 3 -- REGULATORY MATTERS

By letter order issued September 18, 1995, the FERC approved the settlement of the Company's rate filing at Docket No. RP94-162, which required that the Company file a new rate case within three years. On October 8, 1998, the FERC granted a request filed by the Company for an extension of time for the filing of its next general rate case until January 1, 2003. Costs incurred in connection with the extension of the rate case settlement have been deferred and are being amortized on a straight-line basis through the period ending December 31, 2002.

NOTE 4 -- FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying value of cash invested on a temporary basis at short-term market rates of interest approximates the fair market value of the investments.

NOTE 5 -- RELATED PARTY TRANSACTIONS

Transportation revenues derived from affiliated pipeline companies were $.8 million for 1998, $6.2 million for 1997, and $16.7 million for 1996. The Company had no accounts receivable balances due from these affiliates for transportation services at December 31, 1998 and 1997.

Both ANR and U-T Offshore System ("UTOS") provide separation, dehydration and measurement services to HIOS. UTOS is equally owned by affiliates of ANR, Natural Gas Pipeline Company of America, and Leviathan Gas Pipeline Partners, L.P. HIOS incurred charges for these services of $2.5 million in 1998, $2.5 million in 1997, and $2.8 million in 1996 from ANR and $2.0 million in 1998, $1.7 million in 1997, and $1.4 million in 1996 from UTOS.

In February 1996, the Company reached an agreement with ANR, which was approved by the FERC, which provides that rates charged by ANR would be $2.8 million for calendar year 1996, $2.5 million per year for calendar years 1997, 1998 and 1999 and $2.2 million for calendar year 2000. The rate would be negotiated for calendar year 2001 and thereafter.

Amounts due to ANR were $1.9 million and $1.8 million at December 31, 1998 and 1997, respectively, and amounts due to UTOS were $.2 million and $.1 million at December 31, 1998 and 1997, respectively.

HIGH ISLAND OFFSHORE SYSTEM, L.L.C.

NOTES TO THE FINANCIAL STATEMENTS -- (CONTINUED)

NOTE 6 -- COMMITMENTS AND CONTINGENCIES

In the ordinary course of business, the Company is subject to various laws and regulations. In the opinion of management, compliance with existing laws and regulations will not materially affect the financial position or the results of operations of the Company.

NOTE 7 -- LEGAL PROCEEDINGS

In 1996, Jack Grynberg filed a claim under the False Claims Act on behalf of the U.S. government in the U.S. District Court, District of Columbia, against 70 defendants, including the Company. The suit sought damages for the alleged underpayment of royalties due to the purported improper measurement of gas. The 1996 suit was dismissed without prejudice in March 1997 and the dismissal was affirmed by the D.C. Court of Appeals in October 1998. In September 1997, Mr. Grynberg filed 77 separate, similar False Claims Act suits against natural gas transmission companies and producers, gatherers, and processors of natural gas, seeking unspecified damages. The Company has been included in two of the September 1997 suits. The suits were filed in the U.S. District Court, District of Colorado and the U.S. District Court, Eastern District of Michigan. In April 1999, the United States Department of Justice notified the Company that the United States will not intervene in these cases (unaudited).

Although no assurances can be given and no determination can be made at this time as to the outcome of any particular lawsuit or proceeding, the Company believes there are meritorious defenses to substantially all such claims and that any liability which may be finally determined should not have a material adverse effect on the Company's financial position or results of operations.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

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

We have audited the accompanying balance sheets of Poseidon Oil Pipeline Company, L.L.C. (a Delaware limited liability company), as of December 31, 1998 and 1997, and the related statements of income, members' equity and cash flows for the years ended December 31, 1998 and 1997, and for the period from inception (February 14, 1996) through December 31, 1996. 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 generally accepted auditing standards. 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, 1998 and 1997, and the results of its operations and its cash flows for the years ended December 31, 1998 and 1997, and for the period from inception (February 14, 1996) through December 31, 1996, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN LLP

Houston, Texas
March 18, 1999

POSEIDON OIL PIPELINE COMPANY, L.L.C.

BALANCE SHEETS
DECEMBER 31, 1998 AND 1997

	1998	1997
ASSETS		
Current assets:		
Cash and cash equivalents	$ 685,540	$ 1,671,451
Crude oil receivables --		
Related parties	28,216,308	21,729,130
Other	12,179,468	7,316,566
Construction advances to operator (Note 6)	1,234,467	--
Materials, supplies and other	1,022,450	1,045,937
Total current assets	43,338,233	31,763,084
Debt reserve fund (Notes 2 and 4)	4,329,254	3,717,627
Property, plant and equipment, net of accumulated depreciation (Note 3)	228,752,910	222,337,758
Total assets	$276,420,397	$257,818,469
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities:		
Accounts payable --		
Related parties	$ 4,945,839	$ 2,602,133
Other	2,165,159	5,516,554
Crude oil payables --		
Related parties	28,646,791	22,534,661
Other	3,778,243	5,139,391
Other	597,590	70,922
Total current liabilities	40,133,622	35,863,661
Long-term debt (Note 4)	131,000,000	120,500,000
Members' equity (Note 1):		
Capital contributions	107,999,320	107,999,320
Capital distributions	(36,699,320)	(17,999,320)
Retained earnings	33,986,775	11,454,808
Total members' equity	105,286,775	101,454,808
Total liabilities and members' equity	$276,420,397	$257,818,469

The accompanying notes are an integral part of these financial statements.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 1998 AND 1997
AND FOR THE PERIOD FROM INCEPTION (FEBRUARY 14, 1996)
THROUGH DECEMBER 31, 1996

	1998	1997	1996
Crude oil sales	$ 370,431,640	$ 310,828,794	$ 176,849,075
Crude oil purchases	(325,909,477)	(284,667,502)	(169,030,526)
Net sales revenue	44,522,163	26,161,292	7,818,549
Operating costs:			
Transportation costs	1,636,162	3,146,736	858,229
Operating expenses	3,127,134	2,635,717	2,183,375
Depreciation	8,846,395	6,463,327	2,176,157
Total operating costs	13,609,691	12,245,780	5,217,761
Operating income	30,912,472	13,915,512	2,600,788
Other income (expense):			
Interest income	290,745	208,961	339,452
Interest expense	(8,671,250)	(5,340,742)	(269,163)
Net income	$ 22,531,967	$ 8,783,731	$ 2,671,077

The accompanying notes are an integral part of these financial statements.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF MEMBERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 1998 AND 1997
AND FOR THE PERIOD FROM INCEPTION (FEBRUARY 14, 1996)
THROUGH DECEMBER 31, 1996

	MARATHON OIL COMPANY (28%)	POSEIDON PIPELINE COMPANY, L.L.C. (36%)	TEXACO TRADING AND TRANSPORTATION, INC. (36%)	TOTAL
Balance, February 14, 1996	$ --	$ --	$ --	$ --
Cash contributions	5,200,000	--	36,399,660	41,599,660
Property contributions	20,000,000	36,399,660	10,000,000	66,399,660
Cash distributions	--	(3,999,660)	(13,999,660)	(17,999,320)
Net income	747,901	961,588	961,588	2,671,077
Balance, December 31, 1996	25,947,901	33,361,588	33,361,588	92,671,077
Net income	2,459,445	3,162,143	3,162,143	8,783,731
Balance, December 31, 1997	28,407,346	36,523,731	36,523,731	101,454,808
Net income	6,308,951	8,111,508	8,111,508	22,531,967
Cash distributions	(5,236,000)	(6,732,000)	(6,732,000)	(18,700,000)
Balance, December 31, 1998	$29,480,297	$37,903,239	$ 37,903,239	$105,286,775

The accompanying notes are an integral part of these financial statements.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 1998 AND 1997
AND FOR THE PERIOD FROM INCEPTION (FEBRUARY 14, 1996)
THROUGH DECEMBER 31, 1996

	1998	1997	1996
Cash flows from operating activities:			
Net income	$22,531,967	$ 8,783,731	$ 2,671,077
Adjustments to reconcile net income to net cash provided by operating activities --			
Depreciation	8,846,395	6,463,327	2,176,157
Changes in operating assets and liabilities --			
Crude oil receivables	(11,350,080)	2,509,382	(31,555,078)
Materials, supplies and other	23,487	(952,294)	(93,643)
Accounts payable	(1,007,689)	5,939,637	2,179,050
Crude oil payables	4,750,982	(8,098,087)	35,772,139
Other current liabilities	526,668	(16,110)	87,032
Net cash provided by operating activities	24,321,730	14,629,586	11,236,734
Cash flows from investing activities:			
Capital expenditures	(15,261,547)	(54,024,948)	(110,698,884)
Construction advances to operator, net	(1,234,467)	7,407,710	(7,407,710)
Proceeds from the sale of property, plant and equipment	--	146,250	--
Net cash used in investing activities	(16,496,014)	(46,470,988)	(118,106,594)
Cash flows from financing activities:			
Proceeds from issuance of debt	32,000,000	38,000,000	107,000,000
Cash contributions	--	--	41,599,660
Repayments of long-term debt	(21,500,000)	(1,500,000)	(23,000,000)
Cash distributions	(18,700,000)	--	(17,999,320)
Increase in debt reserve fund	(611,627)	(3,717,627)	--
Net cash provided by financing activities	(8,811,627)	32,782,373	107,600,340
Increase in cash and cash equivalents	(985,911)	940,971	730,480
Cash and cash equivalents, beginning of year	1,671,451	730,480	--
Cash and cash equivalents, end of year	$ 685,540	$ 1,671,451	$ 730,480
Supplemental disclosure of cash flow information:			
Cash paid for interest, net of amounts capitalized	$ 8,596,583	$ 5,342,217	$ 205,713
Supplemental disclosure of noncash financing activities:			
Initial Poseidon property contribution	$ --	$ --	$ 36,399,660
Block 873 Pipeline property contribution	$ --	$ --	$ 30,000,000

The accompanying notes are an integral part of these financial statements.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 1998 AND 1997

NOTE 1 -- ORGANIZATION AND NATURE OF BUSINESS

Poseidon Oil Pipeline Company, L.L.C. (the Company), is a Delaware limited liability company formed on February 14, 1996, to design, construct, own and operate the unregulated Poseidon Pipeline extending from the Gulf of Mexico to onshore Louisiana. The original members of the Company were Texaco Trading and Transportation, Inc. (TTTI), and Poseidon Pipeline Company, L.L.C. (Poseidon), a subsidiary of Leviathan Gas Pipeline Partners, L.P. TTTI contributed $36,399,660 in cash, and Poseidon contributed property, plant and equipment, valued by the two parties (TTTI and Poseidon) at $36,399,660, at the formation of the Company. Each member received a 50 percent ownership interest in the Company. Subsequently, $2,799,320 in cash was equally distributed to TTTI and Poseidon, leaving $70 million of equity in the Company as of April 23, 1996.

On July 1, 1996, Marathon Pipeline Company (MPLC) and Texaco Pipeline, Inc. (TPLI), through their 66 2/3 percent and 33 1/3 percent respectively owned venture, Block 873 Pipeline Company (Block 873), contributed property, plant and equipment valued by the parties (Block 873, TTTI and Poseidon) at $30,000,000. In return, they received a 33 1/3 percent interest in the Company. Immediately after the contribution, MPLC and TPLI transferred their pro rata ownership interests in the Company to Marathon Oil Company (Marathon) and TTTI, respectively. Marathon then contributed an additional $5.2 million in cash, and distributions of $12.6 million and $2.6 million in cash were made to TTTI and Poseidon, respectively. Upon completion of this transaction, TTTI, Poseidon and Marathon owned 36 percent, 36 percent and 28 percent of the Company, respectively, and total equity was $90,000,000.

The Company purchased crude oil line-fill and began operating Phase I of the pipeline in April 1996. Phase I consists of 16-inch and 20-inch sections of pipe extending from the Garden Banks Block 72 to Ship Shoal Block 332. Phase II of the pipeline is a 24-inch section of pipe from Ship Shoal Block 332 to Caillou Island. Line-fill was purchased for Phase II in late December 1996 and operations began in January 1997. Construction of Phase III of the pipeline consisting of a section of 24-inch line extending from Caillou Island to the Houma, Louisiana, area was completed during 1997, and operations began in December 1997.

The Company is in the business of transporting crude oil in the Gulf of Mexico in accordance with various purchase and sale contracts with producers served by the pipeline. The Company buys crude oil at various points along the pipeline and resells the crude oil at a destination point in accordance with each individual contract. Net sales revenue is earned based upon the differential between the sale price and purchase price. Differences between purchased and sold volumes in any period are recorded as changes in line-fill.

Effective January 1, 1998, Shell Oil Company and Texaco Inc. (Texaco) formed Equilon Enterprises LLC (Equilon). Equilon is a joint venture which combines both companies' western and midwestern U.S. refining and marketing businesses and both companies' nationwide trading, transportation and lubricants businesses. Under the formation agreement, Shell Oil Company and Texaco assigned, or caused to be assigned, the economic benefits and detriments of certain regulated and unregulated pipeline assets, including TTTI's beneficial interest in the Company. As a result of the joint venture, Equilon became operator of the Company on January 1, 1998.

NOTE 2 -- SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

The accompanying financial statements have been prepared on the accrual basis of accounting in accordance with generally accepted accounting principles.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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 estimated useful lives of three to 30 years. Line-fill is not depreciated as management of the Company believes the cost of all barrels is fully recoverable. Major renewals and betterments are capitalized in the property accounts while maintenance and repairs are expensed as incurred. No gain or loss is recognized on normal asset retirements under the composite method.

Cash and Cash Equivalents

The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Debt Reserve Fund

In connection with the Company's revolving credit facility (see Note 4), the Company is required to maintain a debt reserve account as security on the outstanding balance. At December 31, 1998, the balance in the account totaled $4,329,254 and was comprised of funds earning interest at a money market rate.

Fair Value of Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, short-term receivables, payables and long-term debt. The carrying values of cash and cash equivalents, short-term receivables and payables approximate fair value. The fair value for long-term debt is estimated based on current rates available for similar debt with similar maturities and securities and, at December 31, 1998, approximates the carrying value.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

NOTES TO FINANCIAL STATEMENTS -- (CONTINUED)

NOTE 3 -- PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following at December 31, 1998 and 1997:

	1998	1997
Rights-of-way	$ 3,218,788	$ 3,218,788
Line-fill	11,350,466	11,160,410
Line pipe, line pipe fittings and pipeline construction	223,076,191	206,041,256
Pumping and station equipment	4,613,516	4,584,563
Office furniture, vehicles and other equipment	83,812	67,609
Construction work in progress	3,896,016	5,904,616
	246,238,789	230,977,242
Less -- Accumulated depreciation	(17,485,879)	(8,639,484)
	$228,752,910	$222,337,758

Management evaluates the carrying value of the pipeline in accordance with the guidelines presented under Statement of Financial Accounting Standards (SFAS) No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." SFAS No. 121 establishes standards for measuring the impairment of long-lived assets to be held and used and of those to be disposed. Management believes no impairment of assets exists as of December 31, 1998.

During 1998 and 1997, the Company capitalized approximately $-- and $2,151,000, respectively, of interest cost into property, plant and equipment.

NOTE 4 -- DEBT

The Company maintains a $150,000,000 revolving credit facility with a group of banks. The outstanding balance at December 31, 1998, is $131,000,000. Under the terms of the related credit agreement, the Company has the option to either draw or renew amounts at various maturities ranging from one to 12 months if a Eurodollar interest rate arrangement is selected (6.875 percent to 6.9375 percent at December 31, 1998). These borrowings can then be renewed assuming no event of default exists. Alternatively, the Company may select to borrow under a base interest rate arrangement, calculated in accordance with the credit agreement. The revolving credit facility matures on April 30, 2001.

At December 31, 1998, the entire outstanding balance had been borrowed under the Eurodollar alternative, and it is the Company's intent to extend repayment beyond one year, thus the entire balance has been classified as long-term.

The debt is secured by various assets of the Company including accounts receivable, inventory, pipeline equipment and investments. The Company has used the funds drawn on the revolver primarily for construction costs associated with Phases II and III of the pipeline.

The revolving credit agreement requires the Company to meet certain financial and nonfinancial covenants. The Company must maintain a tangible net worth, calculated in accordance with the credit agreement, of not less than $80,000,000. Beginning April 1, 1997, the Company is required to maintain a ratio of earnings before interest, taxes, depreciation and amortization to interest paid or accrued, as calculated in accordance with the credit agreement, of 2.50 to 1.00. In addition, the Company is required to maintain a debt reserve fund (see Note 2) with a balance equal to two times the interest payments made in the previous quarter under the credit facility.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

NOTES TO FINANCIAL STATEMENTS -- (CONTINUED)

NOTE 5 -- INCOME TAXES

A provision for income taxes has not been recorded in the accompanying financial statements because such taxes accrue directly to the members. The federal and state income tax returns of the Company are prepared and filed by the operator.

NOTE 6 -- TRANSACTIONS WITH RELATED PARTIES

The Company derives a significant portion of its gross sales and gross purchases from its members and other related parties. The Company generated approximately $263,872,000 in gross affiliated sales and approximately $226,184,000 in gross affiliated purchases for 1998. During 1997 and 1996, the Company generated approximately $19,790,000 and $4,086,000 of net sales revenue from related parties.

The Company paid approximately $558,000 to Equilon in 1998 and $454,000 and $401,000 to TTTI in 1997 and 1996, respectively, for management, administrative and general overhead. In 1998, 1997 and 1996, the Company paid construction management fees of $2,133,507, $1,091,000 and $2,364,000, respectively, to Equilon in connection with the completion of Phase II and Phase III. As of December 31, 1998 and 1997, the Company had outstanding advances to Equilon of approximately $1,234,000 and $--, respectively, in connection with construction work in progress.

NOTE 7 -- CONTINGENCIES

In the normal course of business, the Company is involved in various legal actions arising from its operations. In the opinion of management, the outcome of these legal actions will not significantly affect the financial position or results of operations of the Company.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Members
of Neptune Pipeline Company, L.L.C.

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, of members' capital and of cash flows present fairly, in all material respects, the financial position of Neptune Pipeline Company, L.L.C. at December 31, 1998 and 1997, and the result of its operations and its cash flows for the years then ended, in conformity with generally accepted accounting principles. 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 of these statements in accordance with generally accepted auditing standards 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 the opinion expressed above.

PricewaterhouseCoopers LLP

Houston, Texas
March 11, 1999

NEPTUNE PIPELINE COMPANY, L.L.C.

CONSOLIDATED BALANCE SHEET
AS OF DECEMBER 31, 1998 AND 1997

	1998	1997
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,016,841	$ 18,531,456
Transportation receivable	1,279,405	764,008
Owing from related parties	2,880,664	11,974,091
Other receivable	104,756	89,821
Total current assets	10,281,666	31,359,376
Pipelines and equipment	261,104,113	249,861,312
Less: accumulated depreciation	12,204,577	2,056,246
	248,899,536	247,805,066
Long-term receivable	160,000	--
Total assets	$259,341,202	$279,164,442
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities:		
Accounts payable	$ 964,761	$ 2,001,863
Owing to related parties	4,784,102	32,779,237
Deferred income	--	20,478
Total current liabilities	5,748,863	34,801,578
Minority interest	1,872,959	1,778,740
Members' equity	251,719,380	242,584,124
Total liabilities and members' equity	$259,341,202	$279,164,442

The accompanying notes are an integral part of these statements.

NEPTUNE PIPELINE COMPANY, L.L.C.

CONSOLIDATED STATEMENT OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 1998 AND 1997

	1998	1997
Operating income:		
Transportation revenue	$16,172,659	$6,317,728
Other gas revenue	180,236	--
Total revenues	16,352,895	6,317,728
Operating expenses:		
Operating & maintenance	3,575,712	1,693,978
Administrative & general	1,455,240	992,520
Depreciation	10,148,332	2,056,246
Property taxes	326,332	--
Total operating expenses	15,505,616	4,742,744
Net operating income	847,279	1,574,984
Other income (expense)		
Other expense	(150,100)	--
Interest income	385,123	362,142
Allowance for funds used during construction	--	6,430,641
Total other income, net	235,023	6,792,783
Net income before minority interest	1,082,302	8,367,767
Minority interest in income of subsidiaries	11,026	81,736
Net income	$ 1,071,276	$8,286,031

The accompanying notes are an integral part of these statements.

NEPTUNE PIPELINE COMPANY, L.L.C.

CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 1998 AND 1997

	1998	1997
Cash flows from operating activities:		
Net income	$ 1,071,276	$ 8,286,031
Adjustments to reconcile net income to net cash provided by (used for) operating activities:		
Depreciation	10,148,332	2,056,246
Allowance for funds used during construction	--	(6,430,641)
Minority interest in income of subsidiaries	11,026	81,736
(Increases) decreases in working capital:		
Transportation receivables	(515,397)	(764,008)
Owing from related parties	9,093,427	(11,974,091)
Other receivable	25,065	(89,503)
Accounts payable	(1,037,102)	2,001,863
Owing to related parties	(30,791,136)	32,779,237
Deferred income	(20,478)	(54,522)
Net cash provided by (used for) operating activities	(12,014,987)	25,892,348
Cash flows used for investing activities:		
Capital expenditures	(9,252,950)	(179,087,955)
Proceeds from property sales and salvage	187,149	--
Contributions in aid of construction	419,000	--
Net cash used for investing activities	(8,646,801)	(179,087,955)
Cash flows provided by financing activities:		
Members' contributed capital	13,985,491	172,512,990
Minority interest contributed capital	83,193	1,696,980
Distributions	(5,921,511)	(2,560,000)
Net cash provided by financing activities	8,147,173	171,649,970
Increase (decrease) in cash and cash equivalents	$(12,514,615)	$ 18,454,363
Reconciliation of beginning and ending balances		
Cash and cash equivalents -- beginning of year	$ 18,531,456	$ 77,093
Increase (decrease) in cash and cash equivalents	(12,514,615)	18,454,363
Cash and cash equivalents -- end of year	$ 6,016,841	$ 18,531,456

The accompanying notes are an integral part of these statements.

NEPTUNE PIPELINE COMPANY, L.L.C.

STATEMENT OF MEMBERS' CAPITAL
AS OF DECEMBER 31, 1998 AND 1997

	TEJAS OFFSHORE PIPELINE LLC/ SHELL SEAHORSE COMPANY	MARATHON GAS TRANSMISSION INC.	SAILFISH PIPELINE COMPANY LLC	TOTAL
Capital account balances at December 31, 1996	$ 1,194	$ 581	$ 612	$ 2,387
Members' contributions	115,473,693	56,659,297	380,000	172,512,990
Contributed assets	4,100,000	--	60,242,716	64,342,716
Net income	3,433,401	1,328,264	3,524,366	8,286,031
Distributions	--	--	(2,560,000)	(2,560,000)
Capital account balances at December 31, 1997	123,008,288	57,988,142	61,587,694	242,584,124
Members' contributions	5,369,182	3,524,321	5,091,988	13,985,491
Net income	585,317	236,169	249,790	1,071,276
Distributions	(3,358,512)	(1,246,864)	(1,316,135)	(5,921,511)
Capital account balances at December 31, 1998	$125,604,275	$60,501,768	$65,613,337	$251,719,380

The accompanying notes are an integral part of these statements.

NEPTUNE PIPELINE COMPANY, L.L.C.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 1998

NOTE 1 -- ORGANIZATION AND CONTROL

Neptune Pipeline Company, L.L.C. (Neptune) owns a 99% member interest in Manta Ray Offshore Gathering Company, L.L.C. (Manta Ray) and Nautilus Pipeline Company, L.L.C. (Nautilus). Neptune is owned as follows: Tejas Offshore Pipeline, LLC (Tejas), an affiliate of Shell Oil Company owns a 49.9% member interest; Shell Seahorse Company (Shell Seahorse), an affiliate of Shell Oil Company owns a 0.1% member interest; Marathon Gas Transmission Inc. (Marathon) owns a 24.33% member interest; Sailfish Pipeline Company, L.L.C. (Sailfish) owns a 25.67% member interest.

Tejas acquired its 49.9% interest from Shell Seahorse on February 2, 1998.

Agreements between the member companies address the allocation of income and capital contributions and distributions amongst the respective members' capital accounts. As a result of these agreements, the ratio of members' equity accounts per the Statement of Members' Capital differs from the members' ownership interests in Neptune.

Neptune was formed to acquire, construct, own and operate through Manta Ray and Nautilus, the Manta Ray System and the Nautilus System and any other natural gas pipeline systems approved by the members. As of December 31, 1998 the Manta Ray System and the Nautilus System are the only pipelines owned by Manta Ray and Nautilus, respectively.

The formation of Manta Ray was accomplished through cash and fixed asset contributions from the member companies. Fixed asset contributions, which accounted for approximately 50% of all contributions, consisted of the Manta Ray System and various compressor equipment (contributed by Sailfish) and the Boxer-Bullwinkle System (contributed by Shell Seahorse). Because both cash and fixed assets were contributed, the Manta Ray System and related compressor equipment and the Boxer-Bullwinkle System were recorded at $64,342,716, which represented their fair value on the date of contribution.

The Manta Ray System consists of a 169 mile gathering system located in the South Timbalier and Ship Shoal areas of the Gulf of Mexico. An additional segment, 47 miles of 24 inch pipeline and associated facilities, extending from Green Canyon Block 65, offshore Louisiana, to Ship Shoal Block 207, offshore Louisiana, was constructed during 1997 and first provided natural gas transportation service on December 15, 1997. This newly constructed pipeline is referred to as Phase II Facilities elsewhere in these notes.

The Nautilus System consists of a 30-inch natural gas pipeline and appurtenant facilities extending approximately 101 miles from Ship Shoal Block 207, offshore Louisiana, to six delivery point interconnects near the outlet of Exxon Company, U.S.A.'s Garden City Gas Processing Plant in St. Mary Parish, Louisiana. The Nautilus System was constructed during 1997 and first provided natural gas transportation service on December 15, 1997.

Neptune, Manta Ray and Nautilus (collectively referred to as the Companies) have no employees and receive all administrative and operating support through contractual arrangements with affiliated companies. These services and agreements are outlined in Note 3, Related Party Transactions.

NOTE 2 -- SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The consolidated financial statements include the accounts of Neptune and its subsidiaries. All intercompany transactions and balances have been eliminated in consolidation.

NEPTUNE PIPELINE COMPANY, L.L.C.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

Regulation

Nautilus, as an interstate pipeline, is subject to regulation by the Federal Energy Regulatory Commission (FERC). Nautilus has accounting policies that conform to generally accepted accounting principles, as applied to regulated enterprises and are in accordance with the accounting requirements and ratemaking practices of the FERC.

Cash and Cash Equivalents

All highly liquid investments with a maturity of three months or less when purchased are considered to be cash equivalents.

Pipelines and Equipment

Newly constructed pipelines are recorded at historical cost. Regulated pipelines and equipment includes an Allowance for Funds Used During Construction (AFUDC). The rates used in the calculation of AFUDC are determined in accordance with guidelines established by FERC. The Manta Ray pipeline and related facilities are depreciated on a straight-line basis over their estimated useful life of 30 years, while the Nautilus pipeline and related facilities are depreciated on a straight line basis over their estimated useful life of 20 years. Maintenance and repair costs are expensed as incurred while additions, improvements and replacements are capitalized.

Income Taxes

Neptune is treated as a tax partnership under the provisions of the Internal Revenue Code. Accordingly, the accompanying financial statements do not reflect a provision for income taxes since Neptune's results of operations and related credits and deductions will be passed through to and taken into account by its partners in computing their respective tax liabilities.

Impairment of Long-Lived Assets

Statement of Financial Accounting Standard (SFAS) No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" requires recognition of impairment losses on long-lived assets if the carrying amount of such assets, grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows from other assets, exceeds the estimated undiscounted future cash flows of such assets. Measurement of any impairment loss is based on the fair value of the asset. At December 31, 1998 and 1997, there were no impairments.

Revenue Recognition

Revenue from Manta Ray's and Nautilus' transportation of natural gas is recognized upon receipt of natural gas into the pipeline systems.

In the course of providing transportation services to customers, Nautilus and Manta Ray may receive different quantities of gas from shippers than the quantities delivered on behalf of those shippers. These transactions result in imbalances which are settled in cash on a monthly basis. In addition, certain imbalances may occur with interconnecting facilities when the Companies deliver more or less than what is nominated (scheduled). The settlement of these imbalances is governed by Operational Balancing Agreements (OBA). Certain OBAs stipulate that settlement will occur through delivery of physical quantities in subsequent months. The Companies record the net of all imbalances as Transportation Revenue or Other Revenue and carry the net position as a payable or a receivable, as appropriate.

Fair Value of Financial Instruments

The reported amounts of financial instruments such as cash and cash equivalents, receivables, and current liabilities approximate fair value because of their maturities.

Use of Estimates and Significant Risks

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the related reported amounts of revenue and expenses during the reporting period. Such estimates and assumptions include those made in areas of FERC regulations, fair value of financial instruments, future cash flows associated with assets, useful lives for depreciation and potential environmental liabilities. Actual results could differ from those estimates. Management believes that the estimates are reasonable.

Development and production of natural gas in the service area of the pipelines are subject to, among other factors, prices for natural gas and federal and state energy policy, none of which are within the Companies' control.

Reclassification

Certain prior period amounts in the financial statements and notes thereto have been reclassified to conform with the current year presentation.

NOTE 3 -- RELATED PARTY TRANSACTIONS

Construction Management Agreements

On January 17, 1997, Nautilus entered into a Construction Management Agreement (the Agreement) with Marathon under which Marathon agreed to construct the Nautilus System. As of December 31, 1998 and 1997 respectively, Nautilus had incurred $113,127,385, and $113,041,314 of costs under the Agreement. Of these amounts, $309,238 and $2,665,922 were recorded as liabilities to affiliates at December 31, 1998 and 1997, respectively.

On January 17, 1997, Manta Ray entered into a Construction Management Agreement with Shell Seahorse under which Shell Seahorse agreed to construct the Phase II Facilities. Also on January 17, 1997, Manta Ray entered into a Construction Management Agreement with Marathon under which Marathon agreed to construct a slug catcher. On August 1, 1998, Manta Ray entered into a Construction Management Agreement with Marathon under which Marathon agreed to construct condensate stabilization facilities. As of December 31, 1998 and 1997, Manta Ray had incurred $83,388,913 and $64,016,789, respectively, under these agreements. Of these amounts, $4,236,507 and $7,875,533 were recorded as liabilities to affiliates at December 31, 1998 and 1997, respectively.

Transportation Services

During 1998, $3,881,667 of transportation revenues for Nautilus were derived from related parties. During 1997, Nautilus derived substantially all of its transportation revenue from transportation services provided under agreements with Shell Offshore Incorporated (SOI) and Marathon Oil Company, both of which are affiliates of Nautilus. All transactions were at rates pursuant to the existing tariff. At December 31, 1998 and 1997 respectively, Nautilus had affiliate receivables of $596,090 and $0 relating to transportation and gas imbalances. At December 31, 1998 and 1997, respectively, Nautilus had affiliate payables of $230,730 and $0 relating to transportation and gas imbalances.

NEPTUNE PIPELINE COMPANY, L.L.C.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

In 1998, $4,902,613 of transportation revenues on Manta Ray were derived from related parties. During 1997, Manta Ray derived substantially all of its transportation revenue from transportation services provided under agreements with third parties. All transactions were at negotiated rates. At December 31, 1998 and 1997 respectively, Manta Ray had receivables of $1,857,320 and $639,208 relating to transportation and gas imbalances.

At December 31, 1998, Manta Ray also had a receivable from Sailfish of $297,348 relating to accumulated transportation and gas balancing activity associated with the assets contributed by Sailfish.

Leases

Effective December 1, 1997, Manta Ray, as lessor, and Nautilus, as lessee, entered into a lease agreement for usage of offshore platform space located at Ship Shoal Block 207. The term of the lease is for the life of the platform, subject to certain early termination conditions, and requires minimum lease payments of $225,000 per year adjusted annually for inflation. The associated lease revenue and expense have been eliminated in consolidation.

Operating and Administrative Expense

Since the Companies have no employees, operating, maintenance and general and administrative services are provided to the Companies under service agreements with Manta Ray Gathering Company, L.L.C., Marathon, and Shell Seahorse, all of which are affiliates of the Companies. Substantially all operating and administrative expenses were incurred through services provided under these agreements.

Other Affiliate Transactions

During 1997, Manta Ray and Nautilus had various transactions relating to construction with member companies or affiliates which resulted in affiliate receivables of $11,337,218 and affiliate payables of $22,237,782.

Also included in Owing from Related Parties at December 31, 1998 is a receivable from an affiliate for $129,698 relating to the sale of land during the fourth quarter of 1998 by Nautilus. No gain or loss was recognized on the sale.

NOTE 4 -- PIPELINES AND EQUIPMENT

Pipelines and equipment at December 31, 1998 and 1997 is comprised of the following (in thousands):

	1998	1997
Pipelines and equipment	$244,835	$242,194
Land	1,107	1,237
AFUDC	6,430	6,430
Construction in progress	8,732	--
Subtotal	261,104	249,861
Accumulated depreciation	12,204	2,056
Total	$248,900	$247,805

At December 31, 1997, included in pipelines and equipment is an accrued estimate of costs incurred to date of $3,022,000. Actual costs incurred during 1998 relating to this accrual totaled $1,855,000. Pipelines and Equipment and Owing to Related Parties have been adjusted in 1998.

NEPTUNE PIPELINE COMPANY, L.L.C.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

During 1998, Nautilus entered into interconnection agreements with certain other parties in which Nautilus agreed to construct interconnection facilities whereby the parties agreed to contribute $619,000 as partial reimbursement for construction costs. Nautilus was reimbursed $419,000 during 1998 and the remaining balance will be paid monthly based on throughput. The receivable balance at December 31, 1998 was $200,000, the current portion of which is $40,000.

NOTE 5 -- REGULATORY MATTERS

The FERC has jurisdiction over the Nautilus System with respect to transportation of gas, rates and charges, construction of new facilities, extension or abandonment of service facilities, accounts and records, depreciation and amortization policies and certain other matters.

NOTE 6 -- COMMITMENTS AND CONTINGENCIES

In the ordinary course of business, the Companies are subject to various laws and regulations. In the opinion of management, compliance with existing laws and regulations will not materially affect the financial position, the results of operations or cash flows of the Companies.

Various legal actions, which have arisen in the ordinary course of business, are pending with respect to the assets of the Companies. Management believes that the ultimate disposition of these actions, either individually or in aggregate, will not have a material adverse effect on the financial position, the results of operations or the cash flows of the Companies.

Pursuant to the terms of a construction agreement entered into in 1995, Manta Ray agreed to pay liquidated damages to various parties if Manta Ray did not complete an interconnect by May 31, 1998 between the Manta Ray System and the system operated by Trunkline Gas Pipeline Company. Under the provision, Manta Ray incurred $150,000 in 1998, which is recorded in Other Expense. Manta Ray will be obligated to pay an additional $100,000 if the interconnect is not completed by May 31, 1999 and $50,000 if the interconnect is not completed by May 31, 2000.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholder of
Leviathan Gas Pipeline Company

In our opinion, the accompanying balance sheet presents fairly, in all material respects, the financial position of Leviathan Gas Pipeline Company at December 31, 1998 in conformity with generally accepted accounting principles. This financial statement is the responsibility of the Company's management; our responsibility is to express an opinion on this financial statement based on our audit. We conducted our audit of this statement in accordance with generally accepted auditing standards, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statement is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statement, 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 the opinion expressed above.

PricewaterhouseCoopers LLP

Houston, Texas
June 2, 1999

LEVIATHAN GAS PIPELINE COMPANY
(AN INDIRECT SUBSIDIARY OF EL PASO ENERGY CORPORATION)

BALANCE SHEET
DECEMBER 31, 1998
(In thousands, except share data)

ASSETS

Current assets:	
Cash and cash equivalents	$ 6,409
Accounts receivable from the Partnership (Note 5)	406
Other	22
Total current assets	6,837
Equity investment	18,362
Total assets	$25,199

LIABILITIES AND STOCKHOLDER'S EQUITY

Current liabilities:	
Payable to parent	$ 652
Intercompany taxes payable (Note 4)	693
Total current liabilities	1,345
Deferred tax liability (Note 4)	23,154
Total liabilities	24,499
Commitments and contingencies	
Stockholder's equity:	
Common stock, $0.10 par value, 1,000 shares authorized, issued and outstanding	1
Additional paid-in capital	100
Accumulated earnings	599
	700
Total liabilities and stockholder's equity	$25,199

The accompanying notes are an integral part of this financial statement.

LEVIATHAN GAS PIPELINE COMPANY
(AN INDIRECT SUBSIDIARY OF EL PASO ENERGY CORPORATION)

NOTES TO BALANCE SHEET

NOTE 1 -- ORGANIZATION:

Leviathan Gas Pipeline Company ("Leviathan"), a Delaware corporation and indirect wholly-owned subsidiary of El Paso Energy Corporation ("El Paso Energy"), was formed in 1989 to purchase, operate and expand offshore natural gas pipeline systems. El Paso Energy is a diversified energy holding company, engaged, through it subsidiaries, in the interstate and intrastate transportation, gathering and processing of natural gas; the marketing of natural gas, power and other energy-related commodities; power generation; and the development and operation of energy infrastructure facilities worldwide.

In 1993, Leviathan contributed substantially all of its natural gas pipeline operations, certain other assets and liabilities and related acquisition debt to Leviathan Gas Pipeline Partners, L.P. and its subsidiaries (collectively referred to as the "Partnership"), a publicly held Delaware master limited partnership, in exchange for an effective 35.8% interest in the Partnership. Leviathan's effective ownership interest in the Partnership was reduced to 27.3% as a result of an additional public offering by the Partnership in June 1994. The Partnership is primarily engaged in the gathering, transportation and production of oil and natural gas in the Gulf of Mexico and through its subsidiaries and joint ventures, owns interests in significant assets, including (i) eight existing natural gas pipelines, (ii) a crude oil pipeline system, (iii) six strategically-located multi-purpose platforms, (iv) production handling and dehydration facilities, (v) four producing oil and natural gas properties and (vi) a non-producing oil and natural gas property. Leviathan, as general partner, performs all management and operating functions of the Partnership. In August 1998, El Paso Energy paid approximately $422 million to acquire its interest in Leviathan through a merger with DeepTech International Inc. ("DeepTech"), Leviathan's parent.

At December 31, 1998, Preference Units and Common Units totaling 18,075,000 were owned by the public, representing a 72.7% effective limited partner interest in the Partnership. Leviathan, through its ownership of a 25.3% limited partner interest in the form of 6,291,894 Common Units, its 1% general partner interest in the Partnership and its approximate 1% nonmanaging interest in certain subsidiaries of the Partnership, owned a 27.3% effective interest in the Partnership as of December 31, 1998.

NOTE 2 -- SIGNIFICANT ACCOUNTING POLICIES:

Income taxes

Income taxes are based on income reported for tax return purposes along with a provision for deferred income taxes. Deferred income taxes are provided to reflect the tax consequences in future years of differences between the financial statement and tax bases of assets and liabilities at each year-end. Tax credits are accounted for under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. Deferred tax assets are reduced by a valuation allowance when, based upon management's estimates, it is more likely than not that a portion of the deferred tax assets will not be realized in the future period. The estimates utilized in the recognition of deferred tax assets are subject to revision in future periods based on new facts or circumstances.

After August 14, 1998, as a result of El Paso Energy's acquisition of DeepTech, Leviathan's results are included in the consolidated federal income tax return of El Paso Energy. On behalf of itself and all members filing in its consolidated federal income tax return, including Leviathan, El Paso Energy adopted a tax sharing policy (the "Policy") which provides, among other things, that (i) each company in a taxable income position will be currently charged with an amount equivalent to its federal income tax computed on a separate return basis and (ii) each company in a tax loss position will be reimbursed currently to the extent its deductions, including general business credits, were utilized in the consolidated tax return. Under the Policy, El Paso Energy will pay all federal income taxes directly to the IRS and will bill or refund, as applicable, its subsidiaries for their applicable portion of such income tax payments.

LEVIATHAN GAS PIPELINE COMPANY
(AN INDIRECT SUBSIDIARY OF EL PASO ENERGY CORPORATION)

NOTES TO BALANCE SHEET -- (CONTINUED)

Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the related reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates. Management believes that the estimates used are reasonable.

Recent Pronouncements

Effective July 1, 1998, Leviathan adopted Statement of Financial Accounting Standard ("SFAS") No. 129, "Disclosure of Information About Capital Structure" which establishes standards for disclosing information about an entity's capital structure previously not required by nonpublic entities. The adoption of this pronouncement did not have a material impact on Leviathan's financial position or results of operations.

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities". SFAS No. 133 requires that entities recognize all derivative investments as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction. For fair-value hedge transactions in which Leviathan is hedging changes in an asset's, liability's or firm commitment's fair value, changes in the fair value of the derivative instrument will generally be offset in the income statement by changes in the hedged item's fair value. For cash-flow hedge transactions, in which Leviathan is hedging the variability of cash flows related to a variable-rate asset, liability, or a forecasted transaction, changes in the fair value of the derivative instrument will be reported in other comprehensive income. The gains and losses on the derivative instrument that are reported in other comprehensive income will be reclassified as earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The ineffective portion of all hedges will be recognized in current-period earnings. This statement was amended to be effective for fiscal years beginning after June 15, 2000. Leviathan has not yet determined the impact that the adoption of SFAS No. 133 will have on its financial position or results of operations.

NOTE 3 -- EQUITY INVESTMENT:

Leviathan uses the equity method to account for its investment in the Partnership. Additional income is allocated by the Partnership to Leviathan as a result of the Partnership achieving certain target levels of cash distributions to its unitholders. See discussion of incentive distributions below. The summarized financial information for Leviathan's investment in the Partnership is as follows:

LEVIATHAN GAS PIPELINE PARTNERS, L.P.
SUMMARIZED BALANCE SHEET
DECEMBER 31, 1998
(IN THOUSANDS)

Current assets	$ 11,943
Noncurrent assets	430,783
Current liabilities	11,167
Notes payable	338,000
Other noncurrent liabilities	10,724

LEVIATHAN GAS PIPELINE COMPANY
(AN INDIRECT SUBSIDIARY OF EL PASO ENERGY CORPORATION)

NOTES TO BALANCE SHEET -- (CONTINUED)

The Partnership distributes 100% of available cash, as defined in the Partnership Agreement, on a quarterly basis to the unitholders of the Partnership and to Leviathan, as general partner. During the Preference Period (as defined in the Partnership Agreement), these distributions were effectively made 98% to unitholders and 2% to Leviathan, subject to the payment of incentive distributions to Leviathan if certain target levels of cash distributions to unitholders are achieved. As an incentive, the general partner's interest in the portion of quarterly cash distributions in excess of $0.325 per unit and less than or equal to $0.375 per unit is increased to 15%. For quarterly cash distributions over $0.375 per unit but less than or equal to $0.425 per unit, the general partner receives 25% of such incremental amount and for all quarterly cash distributions in excess of $0.425 per unit, the general partner receives 50% of the incremental amount.

NOTE 4 -- INCOME TAXES:

After August 14, 1998, Leviathan is included in the consolidated federal income tax return filed by El Paso Energy. The Policy provides for the manner of determining payments with respect to federal income tax liabilities (Note 2).

Deferred federal income taxes are primarily attributable to the differences in depreciation rates and in the timing of recognizing income from the Partnership for financial and tax reporting purposes.

Leviathan's deferred income tax liabilities (assets) at December 31, 1998 consisted of the following (in thousands):

Deferred tax liabilities:	
Investment in the Partnership	$23,141
Other	13
Total deferred tax liability	23,154
Deferred tax assets:	
Net operating loss ("NOL") carryforwards	(153)
Alternative minimum tax ("AMT") credit carryforward	(1,719)
Valuation allowance	1,872
Total deferred tax assets	--
Net deferred tax liability	$23,154

As of December 31, 1998, approximately $1,719,000 of AMT credit carryforwards, which have no expiration date, were available to offset future regular tax liabilities. Additionally, as of December 31, 1998, approximately $438,000 of NOL carryforwards, which expire in 2017, were available to offset future tax liabilities.

Leviathan has recorded a valuation allowance (i) to reflect the estimated amount of deferred tax assets that may not be realized due to the expiration of NOL carryforwards and (ii) to reflect the uncertainty that the AMT credit carryforwards will be utilized. Leviathan's NOL and AMT credit carryforwards are subject to separate return limitation year restrictions.

Current amounts due to El Paso Energy for the intercompany charge for federal income taxes totaled $693,000 as of December 31, 1998.

NOTE 5 -- RELATED PARTY TRANSACTIONS:

Leviathan, as general partner of the Partnership, is entitled to reimbursement of all reasonable expenses incurred by it or its affiliates for or on behalf of the Partnership including amounts payable by

Leviathan to El Paso Energy under a management agreement whereby El Paso Energy provides operational, financial, accounting and administrative services to Leviathan. The management agreement is intended to reimburse El Paso Energy for the estimated costs of its services provided to Leviathan and the Partnership.

In addition, the management agreement also requires a payment by Leviathan to compensate El Paso Energy for certain tax liabilities resulting from, among other things, additional taxable income allocated to Leviathan due to (i) the issuance of additional Preference Units (including the sale of the Preference Units by the Partnership pursuant to the public offering of additional Preference Units) and (ii) the investment of such proceeds in additional acquisitions or construction projects. The management agreement expires on June 30, 2002, and may thereafter be terminated on 90 days' notice by either party.

NOTE 6 -- COMMITMENTS AND CONTINGENCIES:

In the ordinary course of business, Leviathan is subject to various laws and regulations. In the opinion of management, compliance with existing laws and regulations will not materially effect the financial position of Leviathan. Various legal actions which have arisen in the ordinary course of business are pending with respect to the assets of Leviathan. Management believes that the ultimate disposition of these actions, either individually or in the aggregate, will not have a material adverse effect on Leviathan's financial position.

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4,000,000 COMMON UNITS

LEVIATHAN GAS PIPELINE
PARTNERS, L.P.

REPRESENTING LIMITED PARTNER INTERESTS

PROSPECTUS

, 1999

SALOMON SMITH BARNEY
GOLDMAN, SACHS & CO.
PAINEWEBBER INCORPORATED
DAIN RAUSCHER WESSELS
A DIVISION OF DAIN RAUSCHER INCORPORATED

FIRST UNION CAPITAL MARKETS CORP.

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PART II.

INFORMATION NOT REQUIRED IN PROSPECTUS

ITEM 13. OTHER EXPENSES OF ISSUANCE AND DISTRIBUTION

The following sets forth the estimated expenses and costs expected to be incurred in connection with the issuance and distribution of the securities registered hereby. All of such costs will be borne by the Partnership.

Securities and Exchange Commission registration fee.........	$
Printing..	**
Legal fees and expenses.....................................	**
Accounting fees and expenses................................	**
Miscellaneous...	**
Total	$ **

** To be filed by amendment.

ITEM 14. INDEMNIFICATION OF DIRECTORS AND OFFICERS

The section of the Prospectus entitled "Certain Other Partnership Agreement Provisions -- Indemnification" is incorporated herein by reference. Reference is made to Section 8 of the Underwriting Agreement filed as Exhibit 1.1 to the Registration Statement. Subject to any terms, conditions or restrictions set forth in the Partnership Agreement, Section 17-108 of the Delaware Revised Uniform Limited Partnership Act empowers a Delaware limited partnership to indemnify and hold harmless any partner or other person from and against all claims and demands whatsoever.

Section 145(a) of the General Corporation Law of the State of Delaware (the "DGCL") provides that a Delaware corporation may indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding, whether civil, criminal, administrative or investigative (other than an action by or in the right of the corporation) by reason of the fact that he is or was a director, officer, employee or agent of the corporation or is or was serving at the request of the corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise, against expenses, judgments, fines and amounts paid in settlement actually and reasonably incurred by him in connection with such action, suit or proceeding if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interests of the corporation, and, with respect to any criminal action or proceeding, had no cause to believe his conduct was unlawful.

Section 145(b) of the DGCL provides that a Delaware corporation may indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action or suit by or in the right of the corporation to procure a judgment in its favor by reason of the fact that such person acted in any of the capacities set forth above, against expenses actually and reasonably incurred by him in connection with the defense or settlement of such action or suit if he acted under similar standards, except that no indemnification may be made in respect of any claim, issue or matter as to which such person shall have been adjudged to be liable to the corporation unless and only to the extent that the court in which such action or suit was brought shall determine that despite the adjudication of liability, such person is fairly and reasonably entitled to be indemnified for such expenses which the court shall deem proper.

Section 145 of the DGCL further provides that to the extent a director or officer of a corporation has been successful in the defense of any action, suit or proceeding referred to in subsections (a) and (b) or in the defense of any claim, issue, or matter therein, he shall be indemnified against any expenses actually and reasonably incurred by him in connection therewith; that indemnification provided for by Section 145 shall not be deemed exclusive of any other rights to which the indemnified party may be entitled; and that the corporation may purchase and maintain insurance on behalf of a director, officer, employee or agent of the corporation against any liability asserted against him or incurred by him in any such capacity or arising out of his status as such whether or not the corporation would have the power to indemnify him against such liabilities under Section 145.

Section 102(b)(7) of the DGCL provides that a corporation in its original certificate of incorporation or an amendment thereto validly approved by stockholders may eliminate or limit personal liability of members of its board of directors or governing body for breach of a director's fiduciary duty. However, no such provision may eliminate or limit the liability of a director for breaching his duty of loyalty, failing to act on good faith, engaging in intentional misconduct or knowingly violating a law, paying a dividend or approving a stock repurchase which was illegal or obtaining an improper personal benefit. A provision of this type has no effect on the availability of equitable remedies, such as injunction or rescission, for breach of fiduciary duty.

The Certificate of Incorporation of the general partner contains a provision which limits the liability of the directors of the general partner to the general partner or its stockholder (in their capacity as directors but not in their capacity as officers) to the fullest extent permitted by the DGCL. In addition, the Amended and Restated Bylaws of the general partner (as amended and restated, the "Bylaws"), in substance, require the general partner to indemnify each person who is or was a director, officer, employee or agent of the general partner to the full extent permitted by the laws of the State of Delaware in the event such person is involved in legal proceedings by reason of the fact that he is or was a director, officer, employee or agent of the general partner, or is or was serving at the general partner's request as a director, officer, employee or agent of the general partner and its subsidiaries, another corporation, partnership or other enterprise. The general partner is also required to advance to such persons payments incurred in defending a proceeding to which indemnification might apply, provided the recipient provides an undertaking agreeing to repay all such advanced amounts if it is ultimately determined that he is not entitled to be indemnified. In addition, the Bylaws specifically provide that the indemnification rights granted thereunder are non-exclusive.

The general partner has entered into indemnification agreements with certain of its current and past directors providing for indemnification to the full extent permitted by the laws of the State of Delaware. These agreements provide for specific procedures to assure the directors' rights to indemnification, including procedures for directors to submit claims, for determination of directors' entitlement to indemnification (including the allocation of the burden of proof and selection of a reviewing party) and for enforcement of directors' indemnification rights.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers or persons controlling Leviathan or the general partner pursuant to the foregoing, Leviathan and the general partner have been informed that in the opinion of the SEC such indemnification is against public policy as expressed in the Securities Act and is therefore unenforceable.

ITEM 15. RECENT SALES OF UNREGISTERED SECURITIES

During the past three years, we have issued and sold the unregistered securities described below.

1. On June 1, 1999, we issued 2,661,870 common units, valued at $59.8 million or $22.46 per unit, to EPEC Deepwater Gathering Company in exchange for a 49% partnership interest in Viosca Knoll Gathering Company, as such transaction is more particularly described in this registration statement. We issued these securities in an exempt transaction in reliance on Section 4(2) of the Securities Act of 1933.

2. On May 27, 1999, we issued senior subordinated notes, guaranteed by our subsidiaries, to Donaldson, Lufkin & Jenrette Securities Corporation and Chase Securities Inc. for $175.0 million in cash. We issued these securities in an exempt transaction in reliance on Section 4(2) of the Securities Act of 1933.

ITEM 16. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following is a list of exhibits filed as part of this Registration Statement. Where so indicated by footnote, exhibits which were previously filed are incorporated by reference.

Exhibit No.	Description
1.1**	Underwriting Agreement dated , 1999 among Leviathan Gas Pipeline Partners, L.P., Salomon Smith Barney Inc., Goldman, Sachs & Co., PaineWebber Incorporated, Dain Rauscher Wessels, a division of Dain Rauscher Incorporated, and First Union Capital Markets Corp.
3.1	Certificate of Limited Partnership of Leviathan (filed as Exhibit 3.1 to Leviathan's Registration Statement on Form S-1, File No. 33-55642).
3.2	Amended and Restated Agreement of Limited Partnership of Leviathan (filed as Exhibit 10.41 to Amendment No. 1 to DeepTech's Registration Statement on Form S-1, File No. 33-73538).
3.3	Amendment Number 1 to the Amended and Restated Agreement of Limited Partnership of Leviathan (filed as Exhibit 10.1 to Leviathan's Current Report on Form 8-K dated December 31, 1996, File No. 1-11680).
3.4	Amendment Number 2 to the Amended and Restated Agreement of Limited Partnership of Leviathan (filed as Exhibit 3.4 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
3.5	Certificate of Incorporation of Leviathan Finance Corporation (filed as Exhibit 3.5 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
3.6	Bylaws of Leviathan Finance Corporation (filed as Exhibit 3.6 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
4.1	Indenture dated as of May 27, 1999 among Leviathan Gas Pipeline Partners, L.P., Leviathan Finance Corporation, the Subsidiary Guarantors and Chase Bank of Texas, as Trustee (filed as Exhibit 4.1 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
4.2	First Supplemental Indenture dated as of June 30, 1999 (filed as Exhibit 4.2 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
4.3	Second Supplemental Indenture dated as of July 27, 1999 (filed as Exhibit 4.3 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
4.4	Form of Certificate of 10 3/8% Series A Senior Subordinated Note due 2009 (included in Exhibit 4.1 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
4.5	Form of Certificate of 10 3/8% Series B Senior Subordinated Note due 2009 (included in Exhibit 4.1 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
4.6	Form of Guarantee Notation of securities issued pursuant to the Indenture (included in Exhibit 4.1 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
4.7	A/B Exchange Registration Rights Agreement dated as of May 27, 1999 among Leviathan Gas Pipeline Partners, L.P., Leviathan Finance Corporation, the Subsidiary Guarantors, Donaldson, Lufkin & Jenrette Securities Corporation, and Chase Securities Inc. (filed as Exhibit 4.7 to Leviathan's Registration Statement on Form S-4, File No. 333-81143)
5.1**	Opinion of Akin, Gump, Strauss, Hauer & Feld, L.L.P.

Exhibit No.	Description
10.1	First Amended and Restated Management Agreement, dated June 27, 1994 and effective as of July 1, 1992, between DeepTech International Inc. ("DeepTech") and the General Partner (filed as Exhibit 10.1 to DeepTech's Annual Report on Form 10-K for 1994, File No. 0-23934).
10.2	First Amendment to First Amended and Restated Management Agreement between DeepTech and the General Partner (filed as Exhibit 10.76 to DeepTech's Registration Statement on Form S-1, File No. 33-88688).
10.3	Second Amendment to First Amended and Restated Management Agreement between DeepTech and the General Partner (filed as Exhibit 10.18 to Leviathan's Annual Report on Form 10-K for the fiscal year ended December 31, 1995, File No. 1-11680).
10.4	Third Amendment to First Amended and Restated Management Agreement between DeepTech and the General Partner (filed as Exhibit 10.4 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
10.5	Fourth Amendment to First Amended and Restated Management Agreement between DeepTech and the General Partner (filed as Exhibit 10.1 to Leviathan's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1997, File No. 1-11680).
10.6	Fifth Amendment to First Amended and Restated Management Agreement between DeepTech and the General Partner (filed as Exhibit 10.1 to Leviathan's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1997, File No. 1-11680).
10.7	Sixth Amendment to First Amended and Restated Management Agreement between DeepTech and the General Partner (filed as Exhibit 10.2 to Leviathan's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, File No. 1-11680).
10.8	Redemption Agreement dated February 27, 1998 between Tatham Offshore, Inc. and Flextrend Development Company, L.L.C., a subsidiary of Leviathan (filed as Exhibit 10.1 to Leviathan's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1998, File No. 1-11680).
10.9	Contribution Agreement between Leviathan and El Paso Field Services Company (filed as Exhibit C to Leviathan's Schedule 14A (Rule 14A-101) Proxy Statement effective February 9, 1998).
10.10	Leviathan 1998 Unit Option Plan for Non-Employee Directors Effective as of August 14, 1998 (filed as Exhibit 10.2 to Leviathan's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1998, File No. 1-11680).
10.11	Leviathan Unit Rights Appreciation Plan (filed as Exhibit 10.25 to Leviathan's Annual Report on Form 10-K for the fiscal year ended December 31, 1996, File No. 1-11680).
10.12	Leviathan 1998 Omnibus Compensation Plan, Amended and Restated, Effective as of January 1, 1999 (filed as Exhibit 10.9 to Leviathan's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, File No. 1-11680).
10.13	Purchase and Sale Agreement between Natural Gas Pipeline Company of America as Seller and Leviathan as Buyer dated as of June 30, 1999 (filed as Exhibit 10.1 to Leviathan's Current Report on Form 8-K dated July 15, 1999, File No. 1-11680).
10.14	Third Amended and Restated Credit Agreement dated as of March 23, 1995, as amended and restated through May 27, 1999 among Leviathan, Leviathan Finance Corporation, The Chase Manhattan Bank, as administrative agent, Credit Lyonnais, as syndication agent, BankBoston, N.A., as documentation agent, and the banks and other financial institutions from time to time parties thereto (filed as Exhibit 10.14 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).

Exhibit No.	Description
12.1*	Statement Regarding Computation of Ratios.
21.1*	List of Subsidiaries of Leviathan Gas Pipeline Partners, L.P.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Deloitte & Touche LLP.
23.3*	Consent of Arthur Andersen LLP.
23.4*	Consent of Netherland, Sewell & Associates, Inc.
23.5**	Consent of Akin, Gump, Strauss, Hauer & Feld, L.L.P. (included in Exhibit 5.1 hereto).
24.1*	Power of Attorney (included on the signature pages of this Registration Statement on Form S-3).

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* Filed as an exhibit to this Registration Statement

** To be filed by amendment to this Registration Statement

ITEM 17. UNDERTAKINGS

(b) The undersigned registrant hereby undertakes that, for purposes of determining any liability under the Securities Act of 1933, each filing of the registrant's annual report pursuant to section 13(a) or section 15(d) of the Securities Exchange Act of 1934 (and, where applicable, each filing of an employee benefit plan's annual report pursuant to section 15(d) of the Securities Exchange Act of 1934) that is incorporated by reference in the registration statement shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(h) Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of Leviathan and the general partner pursuant to the foregoing provisions, or otherwise, Leviathan has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by Leviathan of expenses incurred or paid by a director, officer or controlling person of Leviathan in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, Leviathan will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

(i) Leviathan hereby undertakes that:

(1) for purposes of determining any liability under the Act, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by Leviathan pursuant to Rule 424(b)(1) or (4) or 497(h) under the Act shall be deemed to be part of this registration statement as of the time it was declared effective.

(2) For the purpose of determining any liability under the Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, as amended, the Registrant has duly caused this Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on August 26, 1999.

LEVIATHAN GAS PIPELINE PARTNERS, L.P.

By: Leviathan Gas Pipeline Company,
its general partner

By: /s/ GRANT E. SIMS

Name: Grant E. Sims
Title: Chief Executive Officer

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that the persons whose signatures appear below, constitute and appoint H. Brent Austin and Britton White, Jr., and each of them as their true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for them and in their names, places and steads, in any and all capacities, to sign the Registration Statement to be filed in connection with the public offering of limited partnership interest of Leviathan Gas Pipeline Partners, L.P. and any and all amendments (including post-effective amendments) to the Registration Statement, and any subsequent registration statement filed pursuant to Rule 462(b) under the Securities Act of 1933, as amended, and to file the same, with all exhibits thereto, and the other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as they might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, or their or his or her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1933, as amended, this Registration Statement has been signed below by the following persons in the capacities and on the dates indicated below:

SIGNATURE	TITLE	DATE
/s/ WILLIAM A. WISE William A. Wise	Chairman of the Board and Director	August 26, 1999
/s/ GRANT E. SIMS Grant E. Sims	Chief Executive Officer and Director	August 26, 1999
/s/ KEITH B. FORMAN Keith B. Forman	Chief Financial Officer and Vice President	August 26, 1999
/s/ JAMES H. LYTAL James H. Lytal	President and Director	August 26, 1999
/s/ D. MARK LELAND D. Mark Leland	Vice President and Controller (Chief Accounting Officer)	August 26, 1999
/s/ H. BRENT AUSTIN H. Brent Austin	Executive Vice President and Director	August 26, 1999
/s/ ROBERT G. PHILLIPS Robert G. Phillips	Executive Vice President and Director	August 26, 1999
/s/ MICHAEL B. BRACY Michael B. Bracy	Director	August 26, 1999
/s/ H. DOUGLAS CHURCH H. Douglas Church	Director	August 26, 1999
/s/ MALCOLM WALLOP Malcolm Wallop	Director	August 26, 1999

EXHIBIT INDEX

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3.2	Amended and Restated Agreement of Limited Partnership of Leviathan (filed as Exhibit 10.41 to Amendment No. 1 to DeepTech's Registration Statement on Form S-1, File No. 33-73538).
3.3	Amendment Number 1 to the Amended and Restated Agreement of Limited Partnership of Leviathan (filed as Exhibit 10.1 to Leviathan's Current Report on Form 8-K dated December 31, 1996, File No. 1-11680).
3.4	Amendment Number 2 to the Amended and Restated Agreement of Limited Partnership of Leviathan (filed as Exhibit 3.4 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
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4.2	First Supplemental Indenture dated as of June 30, 1999 (filed as Exhibit 4.2 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
4.3	Second Supplemental Indenture dated as of July 27, 1999 (filed as Exhibit 4.3 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
4.4	Form of Certificate of 10 3/8% Series A Senior Subordinated Note due 2009 (included in Exhibit 4.1 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
4.5	Form of Certificate of 10 3/8% Series B Senior Subordinated Note due 2009 (included in Exhibit 4.1 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
4.6	Form of Guarantee Notation of securities issued pursuant to the Indenture (included in Exhibit 4.1 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
4.7	A/B Exchange Registration Rights Agreement dated as of May 27, 1999 among Leviathan Gas Pipeline Partners, L.P., Leviathan Finance Corporation, the Subsidiary Guarantors, Donaldson, Lufkin & Jenrette Securities Corporation, and Chase Securities Inc. (filed as Exhibit 4.7 to Leviathan's Registration Statement on Form S-4, File No. 333-81143)
5.1**	Opinion of Akin, Gump, Strauss, Hauer & Feld, L.L.P.
10.1	First Amended and Restated Management Agreement, dated June 27, 1994 and effective as of July 1, 1992, between DeepTech International Inc. ("DeepTech") and the General Partner (filed as Exhibit 10.1 to DeepTech's Annual Report on Form 10-K for 1994, File No. 0-23934).

Exhibit No.	Description
10.2	First Amendment to First Amended and Restated Management Agreement between DeepTech and the General Partner (filed as Exhibit 10.76 to DeepTech's Registration Statement on Form S-1, File No. 33-88688).
10.3	Second Amendment to First Amended and Restated Management Agreement between DeepTech and the General Partner (filed as Exhibit 10.18 to Leviathan's Annual Report on Form 10-K for the fiscal year ended December 31, 1995, File No. 1-11680).
10.4	Third Amendment to First Amended and Restated Management Agreement between DeepTech and the General Partner (filed as Exhibit 10.4 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
10.5	Fourth Amendment to First Amended and Restated Management Agreement between DeepTech and the General Partner (filed as Exhibit 10.1 to Leviathan's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1997, File No. 1-11680).
10.6	Fifth Amendment to First Amended and Restated Management Agreement between DeepTech and the General Partner (filed as Exhibit 10.1 to Leviathan's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1997, File No. 1-11680).
10.7	Sixth Amendment to First Amended and Restated Management Agreement between DeepTech and the General Partner (filed as Exhibit 10.2 to Leviathan's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, File No. 1-11680).
10.8	Redemption Agreement dated February 27, 1998 between Tatham Offshore, Inc. and Flextrend Development Company, L.L.C., a subsidiary of Leviathan (filed as Exhibit 10.1 to Leviathan's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1998, File No. 1-11680).
10.9	Contribution Agreement between Leviathan and El Paso Field Services Company (filed as Exhibit C to Leviathan's Schedule 14A (Rule 14A-101) Proxy Statement effective February 9, 1998).
10.10	Leviathan 1998 Unit Option Plan for Non-Employee Directors Effective as of August 14, 1998 (filed as Exhibit 10.2 to Leviathan's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1998, File No. 1-11680).
10.11	Leviathan Unit Rights Appreciation Plan (filed as Exhibit 10.25 to Leviathan's Annual Report on Form 10-K for the fiscal year ended December 31, 1996, File No. 1-11680).
10.12	Leviathan 1998 Omnibus Compensation Plan, Amended and Restated, Effective as of January 1, 1999 (filed as Exhibit 10.9 to Leviathan's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, File No. 1-11680).
10.13	Purchase and Sale Agreement between Natural Gas Pipeline Company of America as Seller and Leviathan as Buyer dated as of June 30, 1999 (filed as Exhibit 10.1 to Leviathan's Current Report on Form 8-K dated July 15, 1999, File No. 1-11680).
10.14	Third Amended and Restated Credit Agreement dated as of March 23, 1995, as amended and restated through May 27, 1999 among Leviathan, Leviathan Finance Corporation, The Chase Manhattan Bank, as administrative agent, Credit Lyonnais, as syndication agent, BankBoston, N.A., as documentation agent, and the banks and other financial institutions from time to time parties thereto (filed as Exhibit 10.14 to Leviathan's Registration Statement on Form S-4, File No. 333-81143).
12.1*	Statement Regarding Computation of Ratios.
21.1*	List of Subsidiaries of Leviathan Gas Pipeline Partners, L.P.

Exhibit No.	Description
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Deloitte & Touche LLP.
23.3*	Consent of Arthur Andersen LLP.
23.4*	Consent of Netherland, Sewell & Associates, Inc.
23.5**	Consent of Akin, Gump, Strauss, Hauer & Feld, L.L.P. (included in Exhibit 5.1 hereto).
24.1*	Power of Attorney (included on the signature pages of this Registration Statement on Form S-3).

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* Filed as an exhibit to this Registration Statement

** To be filed by amendment to this Registration Statement

EXHIBIT 12.1

LEVIATHAN GAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	YEAR ENDED DECEMBER 31,					SIX MONTHS ENDED JUNE 30,	
	1994	1995	1996	1997	1998	1998	1999
	(DOLLARS IN THOUSANDS)						
Earnings:							
Income (loss) from continuing operations before minority interests and income taxes....	$22,148	$23,593	$38,318	$(1,456)	$ 290	$ (79)	$ 7,590
Interest and other financing costs.........................	912	833	5,560	14,169	20,242	8,429	13,868
Interest component of rentals...	--	--	--	--	--	--	--
Preferred stock dividend requirements of majority-owned subsidiary....................	--	--	--	--	--	--	--
Total earnings available for fixed charges......	$23,060	$24,426	$43,878	$12,713	$20,532	$8,350	$21,458
Fixed charges:							
Interest and other financing costs.........................	$ 912	$ 6,102	$17,470	$15,890	$21,308	$8,954	$14,623
Interest component of rentals...	--	--	--	--	--	--	--
Preferred stock dividend requirements of majority-owned subsidiary....................	--	--	--	--	--	--	--
Total fixed charges......	$ 912	$ 6,102	$17,470	$15,890	$21,308	$8,954	$14,623
Ratio of Earnings to Fixed Charges.........................	25.3	4.0	2.5	0.8(a)	1.0(b)	0.9(c)	1.5

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(a) As a result of the loss incurred, Leviathan Gas Pipeline Partners, L.P. and its subsidiaries ("Leviathan") were unable to fully cover the indicated fixed charges by $3.2 million due to a non-recurring asset impairment of $21.2 million recorded in June 1997. If the impairment had not occurred, the ratio of earnings to fixed charges would have equaled 2.1x.

(b) Leviathan was unable to cover the indicated fixed charges by $776,000 due primarily to non-recurring expenses of $3.7 million recorded in August 1998 as a result of El Paso Energy Corporation's acquisition of Leviathan's general partner. If the non-recurring expenses had not been incurred, the ratio of earnings to fixed charges would have equaled 1.1x.

(c) As a result of the loss incurred, Leviathan was unable to fully cover the indicated fixed charges by $2.0 million. During the period, Leviathan (1) realized substantially low oil prices, (2) produced less production at Viosca Knoll Block 817 due to the lack of acceptable markets downstream of the Viosca Knoll system and (3) experienced non-recurring start-up costs from two joint venture projects which began operations during the fourth quarter of 1997. These operational events, which have been alleviated, contributed to Leviathan's deficiency in covering its fixed charges.

For the purposes of calculating these ratios: (i) "fixed charges" represents interest costs (whether expensed or capitalized), amortization of debt issue costs, the estimated portion of rental expenses representing the interest factor and preferred stock dividend requirements of majority-owned subsidiaries; and (ii) "earnings" represent the aggregate of income from continuing operations before minority interests and income taxes, interest expense, amortization of debt issue costs, the portion of rental expense representing the interest factor and the actual amount of any preferred stock dividend requirements of majority-owned subsidiaries.

EXHIBIT 21.1

SUBSIDIARIES OF LEVIATHAN GAS PIPELINE PARTNERS, L.P.

NAME OF SUBSIDIARY	JURISDICTION OF ORGANIZATION
Leviathan Finance Corporation	Delaware
Delos Offshore Company, L.L.C	Delaware
Ewing Bank Gathering Company, L.L.C	Delaware
Flextrend Development Company, L.L.C	Delaware
Green Canyon Pipe Line Company, L.L.C	Delaware
Leviathan Finance Corporation	Delaware
Leviathan Oil Transport Systems, L.L.C	Delaware
Leviathan Operating Company, L.L.C	Delaware
Manta Ray Gathering Company, L.L.C	Delaware
Moray Pipeline Company, L.L.C	Delaware
Natoco, L.L.C	Delaware
Poseidon Pipeline Company, L.L.C	Delaware
Sailfish Pipeline Company, L.L.C	Delaware
Stingray Holding, L.L.C	Delaware
Transco Hydrocarbons Company, L.L.C	Delaware
Texam Offshore Gas Transmission, L.L.C	Delaware
Transco Offshore Pipeline Company, L.L.C	Delaware
Tarpon Transmission Company	Texas
UTOS Holding, L.L.C	Delaware
Viosca Knoll Gathering Company	Delaware
VK-Main Pass Gathering Company, L.L.C	Delaware
VK Deepwater Gathering Company, L.L.C	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the use in this Registration Statement on Form S-1 of Leviathan Gas Pipeline Partners, L.P. of (i) our reports dated March 19, 1999 relating to the consolidated financial statements of Leviathan Gas Pipeline Partners, L.P. and subsidiaries and the financial statements of Viosca Knoll Gathering Company, (ii) our report dated March 11, 1999 relating to the consolidated financial statements of Neptune Pipeline Company, L.L.C., (iii) our report dated May 3, 1999 relating to the balance sheet of Leviathan Finance Corporation and (iv) our report dated June 2, 1999 relating to the balance sheet of Leviathan Gas Pipeline Company each of which appears in such Registration Statement. We also consent to the reference to us under the heading "Experts" in such Registration Statement.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
August 26, 1999

EXHIBIT 23.2

INDEPENDENT AUDITORS' CONSENT

We consent to the use in this Registration Statement of Leviathan Gas Pipeline Partners, L.P. on Form S-1 of our report dated February 19, 1999, appearing in this Registration Statement, relating to the statements of financial position of High Island Offshore System, L.L.C. as of December 31, 1998 and 1997 and the related statements of income, members' equity, and cash flows for each of the three years in the period ended December 31, 1998.

We also consent to the reference to us under the heading "Experts" in such Registration Statement.

/s/ DELOITTE & TOUCHE LLP

Detroit, Michigan
August 26, 1999

EXHIBIT 23.3

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the use of our report dated March 18, 1999 relating to the financial statements of Poseidon Oil Pipeline Company, L.L.C., as of December 31, 1998 and 1997 and for the years ended December 31, 1998 and 1997 and the period from inception (February 14, 1996) through December 31, 1996, included in this Registration Statement on Form S-1 of Leviathan Gas Pipeline Partners, L.P., and to all references to our Firm in this Registration Statement.

/s/ ARTHUR ANDERSEN LLP

Houston, Texas
August 26, 1999

EXHIBIT 23.4

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the use in this Registration Statement on Form S-1 of Leviathan Gas Pipeline Partners, L.P. of our reserve report as of December 31, 1998, and all references to our firm appearing in this Registration Statement of Leviathan Gas Pipeline Partners, L.P. for the fiscal year ended December 31, 1998. We also consent to the reference to us under the heading of "Experts" in such Registration Statement.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ FREDERIC D. SEWELL

Frederic D. Sewell
President

Dallas, Texas
August 26, 1999