MARINER ENERGY INC
Form 10-K
April 16, 2002

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

FORM 10-K

For the fiscal year ended December 31, 2001

Commission file number 333-12707

Mariner Energy, Inc.

(Exact name of registrant as specified in its charter)

Internal Revenue Service - Employer Identification No. 86-0460233
State of other jurisdiction of incorporation or organization - Delaware

580 WestLake Park Blvd., Suite 1300
Houston, Texas 77079
(Address of principal executive offices including Zip Code)

(281) 584-5500
(Registrant's telephone number)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT: **NONE**

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirement for the past 90 days. Yes [X]   No [ ]

Note: The Company is not subject to the filing requirements of the Securities Exchange Act of 1934. This quarterly report is filed pursuant to contractual obligations imposed on the Company by an Indenture, dated as of August 1, 1996, under which the Company is the issuer of certain debt.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

The aggregate market value of the voting stock held by non-affiliates of registrant is indeterminable, as there is not established public trading market for the registrant's common stock.

As of March 4, 2002, there were 1,380 shares of the registrant's common stock outstanding. See Part III, Item 13. "Certain Relationships and Related Party Transactions" related to common stock ownership and other entities related to registrant.

TABLE OF CONTENTS

Item		Page
PART I		3
ITEMS 1. AND 2.	BUSINESS AND PROPERTIES	4
	(a) Overview	4
	(b) Recent Events	6
	(c) Business Strategy	7
	(d) Reserves	8
	(e) Oil and Gas Properties	8
	(f) Production	12
	(g) Productive Wells	12
	(h) Acreage	13
	(i) Drilling Activity	14
	(j) Marketing, Customers and Hedging Activities	14
	(k) Competition	15
	(l) Royalty Relief	16
	(m) Regulation	16
	(n) Employees	19
ITEM 3.	LEGAL PROCEEDINGS	19
ITEM 4.	SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS	19
PART II		20
ITEM 5.	MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS	19
ITEM 6.	SELECTED FINANCIAL DATA	20
ITEM 7.	MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	20
	(a) Introduction	20
	(b) General	21
	(c) Enron-Control Relationships and Related Party Transactions	21
	(d) Risk Factors	27
	(e) Critical Accounting Policies and Estimates	31
	(f) Results of Operations	34
	(g) Liquidity and Capital Resources	36
	(h) Recent Events	38
	(i) Recent Accounting Pronouncements	39
ITEM 7A.	QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK	39

TABLE OF CONTENTS

ITEM 8.	FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA	40
PART III		61
ITEM 10.	DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT	61
ITEM 11.	EXECUTIVE COMPENSATION	64
ITEM 12.	SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT	69
ITEM 13.	CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS	70
PART IV		77
ITEM 14.	EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K	77
GLOSSARY		80
SIGNATURES		83

PART I

Mariner Energy, Inc. ("Mariner" or the "Company") has provided definitions for some of the natural gas and oil industry terms used in this report in the "Glossary " on page 82.

Cautionary Statement About Forward-Looking Statements

Some of the information in this Form 10-K contains 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. The forward-looking statements speak only as of the date made, and we undertake no obligation to update such forward-looking statements. These forward-looking statements may be identified by the use of the words "believe," "expect," "anticipate," "will," "contemplate," "would" and similar expressions that contemplate future events and subject to uncertainties. Actual results and trends in the future may differ materially depending on a variety of factors including, but not limited to the following matters:

- Impact of bankruptcy proceedings related to our ultimate parent, Enron Corp. and affiliates;
- cash flow and liquidity;
- financial position;
- business strategy;
- budgets;
- amount, nature and timing of capital expenditures, including future development costs;
- drilling of wells;
- natural gas and oil reserves;
- timing and amount of future production of natural gas and oil;

- operating costs and other expenses;
- prospect development and property acquisitions; and
- marketing of natural gas and oil.

Numerous important factors, risks and uncertainties may affect our operating results, including:

- The risks associated with exploration;
- the ability to find, acquire, market, develop and produce new properties;
- natural gas and oil price volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- operating hazards attendant to the natural gas and oil business;
- downhole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells;
- climatic conditions;
- availability and cost of material and equipment;
- delays in anticipated start-up dates;
- actions or inactions of third-party operators of our properties;
- the ability to find and retain skilled personnel;
- availability of capital;
- the strength and financial resources of competitors;
- regulatory developments;
- environmental risks; and
- general economic conditions.

Any of the factors listed above and other factors contained in this annual report could cause our actual results to differ materially from the results implied by these or any other forward-looking statements made by us or on our behalf. We cannot provide assurance that future results will meet our expectations. You should pay particular attention to the risk factors and cautionary statements described under "Risk Factors" in "Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations."

Items 1. and 2. Business and Properties

(a) Overview

Mariner Energy, Inc. ("Mariner" or "Company") is an independent oil and natural gas exploration, development and production company with principal operations in the Gulf of Mexico and along the U.S. Gulf Coast. We have been an active explorer in the Gulf Coast area since the mid-1980s, when we operated as Hardy Oil Gas USA Inc., and have increased our production and reserve base through the exploitation and development of internally generated prospects, which we refer to as growth "through the drillbit." In 1996, Joint Energy Development Investments Limited Partnership ("JEDI"), an affiliate of Enron Corp. ("Enron") and Enron North America Corp. ("ENA") (also see further description under "Enron" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations"), along with management led a buyout from Hardy Oil & Gas, Plc. JEDI currently owns approximately 96%, while employees and former employees own the remaining 4% of Mariner Energy LLC, which owns 100% of Mariner Holdings, Inc. Mariner Holdings, Inc. owns all of the common stock of Mariner.

Since 1996, we significantly increased our focus in the Gulf of Mexico. Originally our focus included mainly Gulf of Mexico shelf (less than 600 feet water depth) drilling and some Gulf of Mexico deepwater (greater than 600 feet water depth) exploitation projects. These deepwater projects were subsea field developments that were tiebacks to near existing infrastructures (offshore platforms). In 1998, our strategy was modified to seek larger exploration and lower risk exploitation projects in deepwater further from infrastructure, however, we would continue to use subsea field development technology that we had developed. These larger deepwater projects provided opportunities for oil and gas reserve growth. During this time, we were successful in discovering deepwater wells, peaking in 2001, our most successful year in which we drilled seven successful exploratory wells and added approximately 113.1 Bcfe in reserves.

These deepwater projects have higher reserve potential, however, they are also typified by substantially higher development costs and a less uniformed reserve and production growth pattern. In 2001, coinciding with several key management changes, we shifted our focus to a more balanced portfolio approach. We expect to continue to exploit our expertise in deepwater opportunities while also drilling opportunities in the Gulf of Mexico shelf. In addition, it is our current objective to reduce or eliminate our need for capital infusions and reliance on our Revolving Credit Facility.

During 2001, we drilled eleven exploratory wells with seven successes. Ryder Scott Company estimated that we had proved reserves of 237.1 Bcfe as of December 31, 2001, the highest level in our history, of which 74% were natural gas and 26% were oil and condensate. Proved reserves included net reserve additions of 113.1 Bcfe, representing 311% of 2001's company record production of 36.7 Bcfe. Year 2001, additions included first proved reserve bookings from the Yosemite, Falcon, Crater Lake, Swordfish, Roaring Fork and Shasta projects. One successful well, Bass Lite, is still under development evaluation.

We expect our production for 2002 to be slightly higher than 2001's average rate of 100 MMcfe per day, with production from the King Kong / Yosemite project expected to offset anticipated production declines in our other fields. Our 2002 production rate is expected to average 108 Mcfe per day. As of March 4, 2002, our daily production was 117 Mcfe.

In 2002, we expect to drill six to eight exploratory wells. We have also increased our 3-D seismic database and leasehold position in 2002 by committing to a $13 million seismic acquisition payable over 36 months and were apparent high bidder, at $10.9 million, net to us, on 12 central Gulf of Mexico leases at the Central Gulf of Mexico Lease Sale. Development activities in 2002 include the completion of our King Kong / Yosemite and Crater Lake projects, development of the Falcon, Swordfish and Roaring Fork discoveries and several development wells in currently producing fields.

We anticipate capital expenditures for 2002, net of proceeds from property conveyances of $48.8 million, to be approximately $65.4 million for leasehold acquisition, exploration drilling and development projects, compared to our 2001 capital expenditures of approximately $74.0 million, net of proceeds from property conveyances of $90.5 million. We expect to fund our capital expenditures by a combination of internally generated cash flow, proceeds from property conveyances, including the recently-announced sale of half of our remaining interest in the Falcon development project, and borrowings against our Revolving Credit Facility.

The following table sets forth certain summary information with respect to our oil and gas activities and results during the five years ended December 31, 2001. Reserve volumes and values were determined under the method prescribed by the Securities and Exchange Commission, which requires the application of year-end oil and natural gas prices, held constant throughout the projected reserve life. The year-end oil and gas prices utilized do not include any impact relating to hedging activities. See "Reserves" later in this item and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations".

	YEAR ENDING DECEMBER 31, (dollars in millions unless otherwise indicated)

	2001	2000	1999	1998	1997
PROVED RESERVES:					
Oil (MMbbls)	10.1	12.4	9.9	9.4	6.6
Natural gas (Bcf)	176.5	129.3	118.8	128.9	121.4
Natural gas equivalent (Bcfe)	237.1	203.6	178.4	185.1	161.2
PRESENT VALUE OF ESTIMATED FUTURE NET REVENUES (1)	$232.0	$1,043.2	$211.2	$147.6	$176.5
ANNUAL RESERVE REPLACEMENT RATIO (2)	3.2	1.7	1.3	2.0	2.6
CAPITAL EXPENDITURES AND DISPOSAL DATA:					
Capital costs incurred	$164.5	$108.1	$81.5	$141.9	$68.9
Proceeds from property conveyances	(90.5)	(29.0)	(19.8)	--	--
Capital costs net of proceeds from property conveyances	74.0	79.1	61.7	141.9	68.9
PERCENTAGE OF NET CAPITAL COSTS ATTRIBUTABLE TO:					
Lease acquisition	5.4%	10.5%	12.8%	30.4%	36.0%
Exploratory drilling, geological and geophysical	35.0%	19.6%	16.6%	25.1%	39.7%
Development and other	59.6%	69.9%	70.6%	44.5%	24.3%
PRODUCTION:					
Oil (MMbls)	3.0	1.8	0.6	0.8	1.0
Natural gas (Bcf)	18.8	25.7	21.1	19.5	18.0
Natural gas equivalent (Bcfe)	36.7	36.3	24.9	24.2	23.9
AVERAGE REALIZED SALES PRICE PER UNIT (excluding the effects of hedging):					
Oil ($/Bbl)	$22.41	$29.53	$17.53	$12.99	$19.88
Natural gas ($/Mcf)	4.86	4.07	2.48	2.33	2.77
Gas equivalent ($/Mcfe)	4.31	4.32	2.58	2.30	2.87
AVERAGE REALIZED SALES PRICE PER UNIT (including the effects of hedging):					
Oil ($/Bbl)	$23.22	$21.54	$14.11	$12.99	$18.55
Natural gas ($/Mcf)	4.57	3.24	2.16	2.45	2.55
Gas equivalent ($/Mcfe)	4.22	3.24	2.19	2.40	2.68
EXPENSES ($/MCFE):					
Lease operating	$0.55	$0.47	$0.46	$0.41	$0.39
Transportation	0.33	0.22	0.08	0.05	0.05
General and administrative, net	0.25	0.18	0.22	0.20	0.13

1. Discounted at an annual rate of 10%. See "Glossary" included elsewhere in this annual report for the definition of "present value of estimated future net revenues".

2. The annual reserve replacement ratio for a year is calculated by dividing aggregate reserve additions, including revisions, on a Mcfe basis for the year by actual production on an Mcfe basis for such year.

(b) Recent Events

On March 20, 2002, with bids totaling $10.9 million net to us, we were the apparent high bidder solely or with industry partners, on 12 out of 16 blocks on which we and our partners submitted bids in the Central Gulf of Mexico Oil and Gas Lease Sale 182 held on that date. Each of the blocks is in water depths ranging from approximately 20 feet to 2,400 feet. Mariner has a 100% working interest in four of the blocks, 50% working interest in seven blocks and 20% working interest in one block.

In April 2002, we sold 50% of our working interest in our Falcon discovery and surrounding blocks, located in East Breaks Block 579 in the western Gulf of Mexico, for $48.8 million. Subsequent to the sale we have a 25% working interest in the discovery and surrounding blocks. The project is currently expected to begin production in the first quarter of 2003. At December 31, 2001, the Falcon project had 66.8 Bcfe assigned as proven oil and gas reserves to our interest.

The net carrying value of our proved oil and gas properties is limited to an estimate of the future net revenues (discounted at 10%) from proved oil and gas reserves based on period-end prices and costs plus the lower of cost or estimated fair value of unproved properties. As a result of this limitation, based on year-end prices of $2.65 per Mcf of natural gas and $19.43 per Bbl of crude oil, an impairment of oil and gas properties of approximately $37.8 million would be required as of December 31, 2001. However, as allowed by the Securities and Exchange Commission guidelines, since both natural gas and crude oil prices have significantly increased since year-end, no writedown was required as of December 31, 2001.

(c) Business Strategy

Our business strategy is to increase reserves, production and cash flow by emphasizing growth through the drillbit; Our strategy consists of the following elements:

- **Bulk Seismic Purchases.** In 2001 and the first quarter of 2002, we acquired three bulk seismic databases covering blocks in both the shelf and deepwater Gulf of Mexico. We believe maintaining a large 3-D seismic database allows us to identify high quality exploratory prospects. This seismic data allows us to better understand the geology before selecting prospects and increases the probability of accurately identifying the hydrocarbon-bearing zones.

- **Diversify Our Portfolio.** Currently, we maintain several large lease positions in the deepwater Gulf of Mexico. The most significant, our Falcon discovery, we will control with our partners nearby infrastructure, which we believe gives us a competitive advantage in this deepwater area (see "Recent Events" above). In addition, in an effort to balance our portfolio, we recently bid $10.9 million, apparently successfully, for 12 shelf blocks in the 182 Central OCS Gulf of Mexico Lease Sale. We plan on drilling four to five shelf prospects from these leases. Shelf wells are less expensive, lower risk, and can be connected to market relatively quickly compared to Deepwater wells; however, the reserve targets are typically smaller than in the Deepwater.

- **Reduce Dependence on Capital Infusions and Borrowings.** Historically, we have been required to obtain significant capital infusions from ENA (also see further description under "Enron" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations") and to sell various properties in order to manage our cash flow. In 2001, we sold two projects for approximately $90.5 million, which allowed us to maintain a high level of exploratory activity in addition to repaying our Revolving Credit Facility. Subsequent to year-end, we sold 50% of our working interest in our Falcon project for $48.8 million. The proceeds of the sale will be used to maintain an active exploration program and minimize the use of our Revolving Credit Facility. We will continue to monetize non-core assets to redeploy capital into high quality projects.

- **Internally Generate Most of Our Prospects.** By internally generating most of our prospects, we believe we have better control over the quality of the prospects in which we participate, thereby increasing our chances for commercial success. Our geoscientists average more than 20 years of experience in the exploration and production business, including extensive experience in the Gulf and with major oil companies. Through our technical staff's understanding of the geology and geophysics of the Gulf, we intend to continue to generate the majority of our prospects internally.

- **Control Administrative Costs.** In order for us to be competitive, we understand we must control administrative costs. In September 2001, we reduced our workforce by approximately 20%. We believe these reductions will allow us to control costs while maintaining necessary technical expertise. In addition, we will continue to generate reimbursements of costs through joint ventures with partners.

(d) Reserves

The following table sets forth certain information with respect to our proved reserves by geographic area as of December 31, 2001. Reserve volumes and values were determined under the method prescribed by the Securities and Exchange Commission which requires the application of year-end prices held constant throughout the projected reserve life. The reserve information as of December 31, 2001 is based upon a reserve report prepared by the independent petroleum consulting firm of Ryder Scott Company, independent reserve engineers. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Therefore, without reserve additions in excess of production through successful exploration and development activities, the Company's reserves and production will decline. See Note 11 to the Financial Statements included elsewhere in this Annual Report for a discussion of the risks inherent in oil and natural gas estimates and for certain additional information concerning the proved reserves.

AS OF DECEMBER 31, 2001

Geographic Area	PROVED RESERVE QUANTITIES Oil (MMBbls)	Natural Gas (Bcf)	Total (Bcfe)	PRESENT VALUE OF ESTIMATED FUTURE NET RESERVES (1) Dollars in Millions Developed	Undeveloped	Total
Deepwater Gulf	4.3	139.9	165.7	$72.6	$107.6	$180.2
Gulf Shallow Water and Gulf Coast Onshore	1.6	14.7	24.3	15.1	13.7	28.8
Permian Basin	4.2	21.9	47.1	12.1	10.9	23.0
Total	10.0	176.5	237.1	$99.8	$132.2	$232.0
Proved Developed Reserves	4.7	44.0	72.2	$99.8		

1. Discounted (at 10%) present value as of December 31, 2001 (year-end prices held constant).

Our estimates of proved reserves set forth in the foregoing table do not differ materially from those filed by us with other federal agencies.

(e) Oil and Gas Properties

(i) Significant Properties with Proved Reserves as of December 31, 2001

We own oil and gas properties, both producing and not producing, onshore in Texas and offshore in the Gulf, primarily in federal waters. Our 10 largest producing properties, as shown in the following table, accounted for approximately 95% of the Company's proved reserves as of December 31, 2001.

	OPERATOR	MARINER WORKING INTEREST	APPROXIMATE WATER DEPTH (FEET)	PRODUCING WELLS(3)	DATE PRODUCTION COMMENCED/ EXPECTED	NET PROVED RESERVES (BCFE)
DEEPWATER GULF:						
East Breaks 579 *(Falcon)*(1)	Mariner	50%	3,400	-	1st quarter 2003	66.8
Green Canyon 472 *(King Kong)*	Mariner	50%	3,900	-	1st quarter 2002	31.1
Mississippi Canyon 718 *(Pluto)*	Mariner	51%	2,710	1	December 1999	16.3
Ewing Bank 966 *(Black Widow)*	Mariner	69%	1,850	1	October 2000	15.9
Green Canyon 516 *(Yosemite)*	Mariner	44%	3,850	-	1st quarter 2002	14.9
Viosca Knoll 917 *(Swordfish)*	Mariner	15%	4,200	-	4th quarter 2003	10.1
Mississippi Canyon 322 *(Crater Lake)*	Walter O&G	40%	700	-	1st quarter 2002	5.5
GULF SHALLOW WATER AND GULF COAST ONSHORE:						

	OPERATOR	MARINER WORKING INTEREST	APPROXIMATE WATER DEPTH (FEET)	PRODUCING WELLS(3)	DATE PRODUCTION COMMENCED/ EXPECTED	NET PROVED RESERVES (BCFE)
South Timbalier 316 *(Roaring Fork)*	Westport	20%	450	-	3rd quarter 2003	12.9
Brazos A-105	Spirit	12.5%	192	5	January 1993	5.1
PERMIAN BASIN OF WEST TEXAS:						
Spraberry Aldwell Unit(2)	Mariner	70.3%	Onshore	81	1949	46.9
OTHER PROPERTIES:	--	--	--	49	--	11.6
TOTAL PROVED RESERVES:						237.1

1. In April 2002, 50% of our working interest was sold for $48.8 million.
2. We operate the unit and own working interests in individual wells ranging from approximately 33% to 84%.
3. King Kong and Crater Lake projects began production in February 2002 and our Yosemite project began production in April 2002.

Following is additional information regarding the properties in the table shown above.

Gulf of Mexico

East Breaks 579 (Falcon) Mariner generated and acquired the Falcon prospect at a federal lease sale in August 1997. We operate and have a 50% working interest (prior to the April 2002 sale of 50%) in this project, which is located in the deepwater Gulf of Mexico 95 miles southeast of Corpus Christi, Texas in a water depth of 3,400 feet. In April 2001, the Mariner EB 579 #1 well was drilled and yielded a significant discovery that was sanctioned for development in October of the same year. Estimated net proved reserves from Falcon are 66.8 Bcfe. First production is anticipated to commence in first quarter of 2003 (also see "Recent Events").

Green Canyon 472 / Green Canyon 516 (King Kong / Yosemite) In July 2000, we entered into an agreement to acquire Shell Exploration and Production Company's 50% working interest in the "King Kong" Gulf of Mexico development project. The project is located in approximately 3,900 feet of water in Green Canyon Blocks 472 and 473, approximately 150 miles southeast of New Orleans. We purchased Shell's interest for an undisclosed amount of cash and overriding royalty interest in the field, and have been named operator for development of the project. Agip Petroleum Co. Inc., as a successor to British Borneo, owns the remaining 50% working interest. This project began production in February 2002 and it ties back 16 miles to the Allegheny mini-TLP operated by Agip. In 2001 we drilled our "Yosemite" exploration prospect located adjacent to King Kong in Green Canyon Block 516. Yosemite is jointly developed with King Kong. The combined projects have estimated net proved reserves of 46.0 Bcfe as of December 31, 2001 and as of April 15, 2002 were producing at a gross rate of 165 Mmcfe per day.

Mississippi Canyon 718 (Pluto) We acquired a 30% interest in this project in 1997, two years after British Petroleum discovered gas on the project. We later increased our ownership to 97%, acquiring operatorship and gaining overall control of project planning and implementation. In 1998, we increased our working interest to 100% and submitted a deepwater royalty relief application that was granted in July 1999. Due to high natural gas commodity prices, however, royalty relief did not apply to natural gas production in 2000 or 2001. In June 1999, we sold a 63% working interest in the project to Burlington Resources, Inc., reducing our working interest to 37%. After project payout, which occurred in the third quarter of 2000, our working interest increased to 51% and Burlington's working interest decreased to 49%. We developed the field with a single subsea well which is located in the Gulf approximately 150 miles southeast of New Orleans, Louisiana at a water depth of 2,710 feet and a flow line tied back approximately 29 miles to a production platform on the shelf. Production began on December 29, 1999 and through December 31, 2001 the field produced net 21.5 Bcfe. As of December 31, 2001, the field had estimated remaining net proved reserves of 16.3 Bcfe, 75% of which was natural gas.

Ewing Bank 966 (Black Widow) We acquired the Black Widow prospect at a federal offshore Gulf lease sale in March 1997. We operate and have a 69% working interest in this project, which is located in the Gulf approximately 130 miles south of New Orleans, Louisiana at a water depth of approximately 1,850 feet. In early 1998, we drilled a successful exploration well on the prospect. We commenced production in the fourth quarter of 2000 via subsea tieback to an existing platform, and the field has produced through

December 31, 2001 net 14.85 Bcfe. Estimated remaining net proved reserves from Black Widow are approximately 15.9 Bcfe, 87.6% of which is oil.

Viosca Knoll 917 (Swordfish) Mariner entered into a farmout agreement with BP (Amoco) in September 2001 to drill the Swordfish prospect. We operate and have a 15% working interest in this project, which is located in the deepwater Gulf of Mexico 105 miles southeast of New Orleans, Louisiana in water depths that range from 4,200 feet. In November and December of 2001, Mariner drilled two successful exploration wells on the prospect. Estimated net proved reserves for the Swordfish prospect are 10.1 Bcfe. First production is anticipated to commence in the fourth quarter of 2003.

Mississippi Canyon 322 (Crater Lake) Mariner generated and acquired the Crater Lake prospect at a federal sale in March of 1998. Mariner has a 40% working interest in this Walter Oil & Gas operated project, which is located in the deepwater Gulf of Mexico 75 miles southeast of New Orleans, Louisiana in a water depth of 700 feet. In May of 2001, Walter Oil and Gas drilled a successful exploration well and a successful appraisal that were later completed. First production from the initial discovery well began February 2002, and the current rate is 10 mmcfd. Production from the second well will begin upon depletion of the initial well. The estimated net proved reserves from Crater Lake are 5.5 Bcfe.

South Timbalier 316 (Roaring Fork) Mariner entered into a farmout agreement with Westport and Samedan in October 2001 to participate in the drilling of the Roaring Fork prospect. Mariner has a 20% working interest in this Westport operated project, which is located in the Gulf of Mexico 135 miles south of New Orleans, Louisiana in a water depth of 450 feet. Westport drilled a successful exploration well on the prospect followed by two successful appraisal wells. The estimated net proved reserves for the Roaring Fork prospect are 12.9 Bcfe. First production is anticipated to commence in the fourth quarter of 2003.

Brazos A-105 We generated the Brazos A-105 prospect and own a 12.5% working interest in this Spirit Energy-operated property, which commenced production in January 1993. Five wells exploit a single reservoir. No additional wells are currently anticipated. The field has produced 26.6 Bcfe net to us from its inception through December 31, 2001. The field had estimated remaining net proved reserves of 5.1 Bcfe as of December 31, 2001, 99% of which was natural gas.

Permian Basin of West Texas

Spraberry Aldwell Unit We acquired our interest in the Spraberry Aldwell Unit, located in Reagan County, Texas, in 1985. The 18,250-acre unit is located in the heart of the Spraberry Trend southeast of Midland, Texas and has produced oil since 1949. We operate the unit and own working interests in individual wells ranging from approximately 33% to 84%. We initiated an infill drilling program in 1987 innovatively commingling the unitized Spraberry formation with the non-unitized Dean formation. To date, 72 infill wells have been drilled resulting in 71 productive wells. Currently, there are a total of 81 producing wells in the unit. Depending upon, among other things, the future prices of oil and natural gas, we may drill 20 to 40 additional infill wells, bringing proved undeveloped reserves into production, in the next two to four years at a projected cost of approximately $340,000 to $400,000 per well. We estimate that the field's remaining net proved reserves as of December 31, 2001 were 46.9 Bcfe. We believe that the field's potential for continued economic oil production exceeds 40 years.

(ii) Disposition of Properties

We periodically evaluate and, when appropriate, sell certain of our producing properties that we consider to be marginally profitable or outside of our areas of concentration. We also consider the sale of discoveries that are not yet producing when we believe we can obtain acceptable returns on our investment without holding the investment through depletion. Such sales enable us to maintain financial flexibility, reduce overhead and redeploy the proceeds to activities that we believe have a higher potential financial return. No property dispositions of producing properties were made during the three years ending December 31, 2001. However, in 2001, 2000 and 1999 we sold a 63% gross pre-payout interest in our Pluto project for approximately $19 million (our post-payout interest is a 51% working interest), a 20% gross interest in our Devils Tower project for $25 million and a 30% gross interest in our Devils Tower project and 50% interest in our Aconcagua project for $39.5 million and $51 million respectively. In April 2002, we sold 50% of our working interest in the Falcon project for $48.8 million. See "Recent Events" above.

(iii) Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interferes with the use of such properties in the operation of our business.

We believe that we have satisfactory title to or rights in all of our producing properties. As is customary in the oil and natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. Title investigation is made, and title opinions of local counsel are generally obtained, only before commencement of drilling operations. We believe that title issues generally are not as likely to arise on offshore oil and gas properties as on onshore properties.

(f) Production

The following table presents certain information with respect to oil and natural gas production attributable to our properties, average sales price received and expenses per unit of production during the periods indicated.

	Year Ending December 31,		
	2001	**2000**	**1999**
PRODUCTION:			
Oil (MMbbls)	3.0	1.8	0.6
Natural gas (Bcf)	18.8	25.7	21.1
Natural Gas equivalent ((Bcfe)	36.7	36.3	24.9
AVERAGE REALIZED SALES PRICE PER UNIT (EXCLUDING EFFECTS OF HEDGING):			
Oil ($/Bbl)	$22.41	$29.53	$17.53
Natural gas ($/Mcf)	4.86	4.07	2.48
Natural Gas equivalent ($/Mcfe)	4.31	4.32	2.58
AVERAGE REALIZED SALES PRICE PER UNIT (INCLUDING EFFECTS OF HEDGING):			
Oil ($/Bbl)	$23.22	$21.54	$14.11
Natural gas ($/Mcf)	4.57	3.24	2.16
Natural Gas equivalent ($/Mcfe)	4.22	3.24	2.19
EXPENSES ($/MCFE):			
Lease operating	$0.55	$0.47	$0.46
Transportation	0.33	0.22	0.08
General and administrative, net (1)	0.25	0.18	0.22
Depreciation, depletion and amortization	1.73	1.57	1.29
CASH MARGIN ($/MCFE) (2)	$2.86	$2.26	$1.18

1. Net of overhead reimbursements received from other working interest owners and amounts capitalized under the full cost accounting method.
2. Average equivalent gas sales price (including the effects of hedging prior to de-designation as a hedge), minus lease operating and gross general and administrative expenses.

(g) Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned a working interest at December 31, 2001:

	TOTAL PRODUCTIVE WELLS	
	GROSS	NET
Oil	88	61.6
Gas	49	8.9

	TOTAL PRODUCTIVE WELLS	
TOTAL	137	70.5

Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections. We have six wells that are completed in more than one producing horizon; those wells have been counted as single wells.

(h) Acreage

The following table sets forth certain information with respect to the developed and undeveloped acreage as of December 31, 2001.

	DEVELOPED ACRES(1)		UNDEVELOPED ACRES (2)	
	GROSS	NET	GROSS	NET
Texas (Onshore)	18,337	12,300	631	343
Other states (Onshore)	671	212	574	126
Offshore	317,244	100,571	257,760	139,031
Total	336,252	113,083	258,965	139,500

1. Developed acres are acres spaced or assigned to productive wells.
2. Undeveloped acres are 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 such acreage contains proved reserves.

(i) Drilling Activity

Certain information with regard to our drilling activity during the years ended December 31, 2001, 2000 and 1999 is set forth below.

	YEAR ENDING DECEMBER 31,					
	2001		2000		1999	
	GROSS	NET	GROSS	NET	GROSS	NET
EXPLORATORY WELLS:						
Producing	7	2.48	1	0.40	3	1.75
Dry	4	1.50	3	2.08	2	0.50
Total	11	3.98	4	2.48	5	2.25

	YEAR ENDING DECEMBER 31,					
DEVELOPMENT WELLS:						
Producing	7	2.40	2	0.45	8	1.61
Dry	1	0.33	--	--	--	--
Total	8	2.73	2	0.45	8	1.61
TOTAL WELLS:						
Producing	14	4.88	3	0.85	11	3.36
Dry	5	1.83	3	2.08	2	0.50
Total	19	6.71	6	2.93	13	3.86

(j) Marketing, Customers and Hedging Activities

We market substantially all oil and gas production from properties we operate and properties operated by others where our interest is significant. The majority of our natural gas, oil and condensate production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market-sensitive prices. As to gas produced from the Spraberry Aldwell Unit, we have a long-term agreement for the sale and processing of such gas on terms that we believe to be competitive. The following table lists customers accounting for more than 10% of our total revenues for the year indicated.

	PERCENTAGE OF TOTAL REVENUES FOR THE YEAR ENDING DECEMBER 31,		
CUSTOMER	**2001**	**2000**	**1999**
Enron North America and affiliates (An affiliate of the Company)	32%	49%	26%
Genesis Crude Oil LP	24%	--	21%
Duke Energy	14%	16%	13%

Due to the nature of the markets for oil and natural gas, we do not believe that the loss of any one of these customers would have a material adverse effect on our financial condition or results of operations. Effective December 2001, we no longer sold our production to ENA. The loss of ENA as a purchaser has not had a material effect on the commodity prices we have received (also see further description under "Enron" in "Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations").

The following table sets forth the results of hedging transactions during the periods indicated. For the year ended December 31, 2001, the amounts are reflective of the results up to the point of de-designation (also see further description under "Enron" in "Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations") (December 2, 2001), which include all settled contract months through December of 2001:

The following table sets forth the results of hedging transactions during the periods indicated:

	YEAR ENDING DECEMBER 31,		
	2001	**2000**	**1999**
Natural gas quantity hedged (Mmbtu)	17,733	19,569	18,818

	YEAR ENDING DECEMBER 31,		
Increase (decrease) in natural gas sales (thousands)	$(5,523)	($21,364)	($6,741)
Crude oil quantity hedged (MBbls)	752	1,059	389
Increase (decrease) in crude oil sales (thousands)	$2,393	($14,053)	($2,152)

The following table sets forth our open positions as of December 31, 2001.

TIME PERIOD	NOTIONAL QUANTITIES	FIXED PRICE	FAIR VALUE (in millions)
NATURAL GAS (MMBTU)			
January 1 - October 31, 2002			
Fixed price swap purchased	1,831	$2.18	$(0.9)
January 1 - December 31, 2002			
Fixed price swap purchased	12,134	4.43	20.4
April 1 - December 31, 2002			
Fixed price swap purchased	4,125	3.03	0.9
January 1 - December 31, 2003			
Fixed price swap purchased	3,650	3.74	2.0
CRUDE OIL (MBBL)			
January 1 - June 30, 2002			
Fixed price swap purchased	181	25.15	0.9
January 1 - December 31, 2002			
Fixed price swap purchased	365	25.48	1.9
Sub-Total			$25.2(1)
Allowance for impairment			$(22.7)
Total			$2.5

1. Subsequent to the date of default by Enron and ENA, and as of December 31, 2001, the contracts decreased in gross market value by $523,000, which is reflected in the impairment of related party receivables at the net valuation of 10% or $52,000, after consideration for allowance.

(k) Competition

We believe that the locations of our leasehold acreage, our exploration, drilling and production capabilities, and our experience generally enable us to compete effectively. However, our competitors include major integrated oil and natural gas companies and numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our larger competitors possess and employ financial and personnel resources substantially greater than those available to us. Such companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to discover reserves in the future is dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry.

(l) Royalty Relief

The Outer Continental Shelf Deep Water Royalty Relief Act (the "RRA"), signed into law on November 28, 1995, provides that all tracts in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude in water more than 200 meters deep offered for bid within five years of the RRA will be relieved from normal federal royalties as follows:

WATER DEPTH	ROYALTY RELIEF
200 - 400 meters	no royalty payable on the first 105 Bcfe produced
400 - 800 meters	no royalty payable on the first 315 Bcfe produced
800 meters or deeper	no royalty payable on the first 525 Bcfe produced

The RRA also allows mineral interest owners the opportunity to apply for royalty relief for new production on leases acquired before the RRA was enacted. If the United State Minerals Management Service ("MMS") determines that new production would not be economical without royalty relief, then a portion of the royalty may be relieved to make the project economical.

The impact of royalty relief is significant, as normal royalties for leases in water depths of 400 meters or less is 16.7%, and normal royalties for leases in water depths greater than 400 meters is 12.5%. Royalty relief can substantially improve the economics of projects in deep water. In the event that prices exceed certain prescribed thresholds royalty relief is suspended. In 2000 and 2001, our Pluto, Black Widow, Garden Banks 179 and King Kong projects qualified for royalty relief however natural gas prices exceeded the thresholds. Consequently, we have been required to pay royalties on natural gas for both 2000 and 2001. As of December 31, 2001, we have accrued $4.7 million related to this obligation.

(m) Regulation

Our operations are subject to extensive and continually changing regulation affecting the oil and natural gas industry. Many departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding on the oil and natural gas industry and its individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. We do not believe that we are affected in a significantly different manner by these regulations than are our competitors.

(i) Transportation and Sale of Natural Gas

The FERC (Federal Energy Regulatory Commission) regulates interstate natural gas pipeline transportation rates and service conditions, which affect the marketing of gas produced by us and the revenues received by us for sales of such natural gas. In 1985, the FERC adopted policies that make natural gas transportation accessible to natural gas buyers and sellers on an open-access, non-discriminatory basis. The FERC issued Order No. 636 on April 8, 1992, which, among other things, prohibits interstate pipelines from tying sales of gas to the provision of other services and requires pipelines to unbundle the services they provide. This has enabled buyers to obtain natural gas supplies from any source and secure independent delivery service from the pipelines. All of the interstate pipelines subject to FERC s jurisdictions are now operating under Order No. 636 open access tariffs. On July 29, 1998, the FERC issued a Notice of Proposed Rulemaking regarding the regulation of short term natural gas transportation services. In a related initiative, FERC issued a Notice of Inquiry on July 29, 1998 seeking input from natural gas industry players and affected entities regarding virtually every aspect of the regulation of interstate natural gas transportation services. As a result, the FERC issued Order No. 637 (final rule on February 9, 2000) amending its transportation regulation in response to the growing development of more competitive markets for natural gas and the transportation of natural gas. Order No. 637 revises the regulatory framework to improve the efficiency of the natural gas market and provide captive customers with the opportunity to reduce their cost of holding long-term pipeline capacity. The rate revises the FERC s pricing policy to enhance market efficiency for short term released capacity and permit pipelines to file for peak and off-peak and term differentiated rate structures. Order No. 637 further improves the Commission s reporting requirements and permits more effective monitoring of the natural gas market.

Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their effect, if any, on our operations. The natural gas industry historically has been closely regulated; thus, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue indefinitely into the future.

(ii) Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of state and federal statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. Most states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of the spacing, plugging and abandonment of wells. Many states also restrict production to the market demand for oil and natural gas and several states have indicated interest in revising applicable regulations. The effect of these regulations is to limit the amount of oil and natural gas we can produce from our wells and the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to production and sale of crude oil, natural gas and gas liquids within its jurisdiction.

Most of our offshore operations are conducted on federal leases that are administered by the MMS and are required to comply with the regulations and orders promulgated by MMS. Among other things, we are required to obtain prior MMS approval for our exploration, development and production plans for these leases. The MMS regulations also establish construction requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the removal of production facilities from these leases. Under certain circumstances, the MMS could require us to suspend or terminate our operations on a federal lease.

In addition, a portion of our Sandy Lake Properties is located within the boundaries of the Big Thicket National Preserve (the "BTNP"), which is under the jurisdiction of the United States National Park Service (the "NPS"). Our operations within the BTNP must comply with regulations of the NPS. In general, these regulations require us to obtain NPS approval of a plan of operations for any activity within the BTNP or to demonstrate that a waiver of a plan of operations is appropriate. Compliance with these regulations increases our cost of operations and may delay the commencement of specific operations.

(iii) Environmental Regulations

General. Various federal, state and local laws and regulations governing the discharge of materials into the environment, or otherwise relating to the protection of the environment, affect our operations and costs. In particular, our exploration, development and production operations, activities in connection with storage and transportation of crude oil and other liquid hydrocarbons and use of facilities for treating, processing or otherwise handling hydrocarbons and wastes therefrom are subject to stringent environmental regulation. As with the industry generally, compliance with existing regulations increases our overall cost of business. Such areas affected include unit production expenses primarily related to the control and limitation of air emissions and the disposal of produced water, capital costs to drill exploration and development wells resulting from expenses primarily related to the management and disposal of drilling fluids and other oil and gas exploration wastes and capital costs to construct, maintain and upgrade equipment and facilities.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as "Superfund", imposes liability, without regard to fault or the legality of the original act, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the "owner" or "operator" of the site and companies that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA also authorizes the Environmental Protection Agency and, in some instances, third parties to act 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. In the course of its ordinary operations, we may generate waste that may fall within CERCLA's definition of a "hazardous substance". We may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the exploration and production of oil and gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or release of hydrocarbons or other wastes were not under our control. These properties and wastes disposed thereon may be subject to CERCLA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination.

Oil Pollution Act of 1990. The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose liability on "responsible parties" for damages resulting from crude oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. Liability under the OPA is strict, joint and several, and potentially unlimited. A "responsible party" includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. The OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35 million ($10 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to a crude oil spill for which such person is statutorily responsible. The amount of required financial responsibility may be increased above the minimum amounts to an amount not exceeding $150 million depending on the risk represented by the quantity or quality of crude oil that is handled by the facility. The MMS has promulgated regulations that implement the financial responsibility requirements of the OPA. A failure to comply with the OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under the OPA and we believe that compliance with the OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

Clean Water Act. The Federal Water Pollution Control Act of 1972, as amended (the "Clean Water Act"), imposes restrictions and controls on the discharge of produced waters and other oil and gas wastes into navigable waters. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into state and federal waters. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and gas industry into certain coastal and offshore water. The Clean Water Act provides for civil, criminal and administrative penalties for unauthorized discharges for oil and other hazardous substances and imposes liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. Comparable state statutes impose liabilities and authorize penalties in the case of an unauthorized discharge of petroleum or its derivatives, or other hazardous substances, into state waters. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Resources Conservation Recovery Act. The Resource Conservation Recovery Act ("RCRA") is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most crude oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes crude oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

(n) Employees

As of December 31, 2001, we had 55 full-time employees. Our employees are not represented by any labor unions. We consider relations with our employees to be satisfactory. We have never experienced a work stoppage or strike.

Item 3. Legal Proceedings

In the ordinary course of business, we are a claimant and/or a defendant in various legal proceedings, including proceedings as to which we have insurance coverage, in which the exposure, individually and in the aggregate, is not considered material to us.

Also see further description under "Enron" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" regarding matters that could impact the Company operations.

Item 4. Submission of Matters to a Vote of Security Holders

None.

PART II

Item 5. Market for Registrant s Common Equity and Related Stockholder Matters

There is no established public trading market for our common stock, our only class of equity securities.

See Part III, Item 13. "Certain Relationships and Related Party Transactions" related to common stock ownership and other entities related to registrant.

Item 6. Selected Financial Data

The information below should be read in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements included in Item 8 of this report. The following table sets forth selected financial data for the periods indicated.

(All amounts in millions)

	YEAR ENDING DECEMBER 31,				
STATEMENT OF OPERATIONS DATA:	**2001**	**2000**	**1999**	**1998**	**1997**
Total revenues	$155.0	$121.1	$54.5	$58.0	$64.1
Lease operating expenses	20.1	17.2	11.5	9.9	9.4
Transportation	12.0	7.8	2.0	1.3	1.3
Depreciation, depletion and amortization	63.5	56.8	32.1	33.8	31.7
Impairment of oil and gas properties	--	--	--	50.8	28.5
Impairment of Enron related receivables	29.5	--	--	--	--
Provision for Litigation	--	--	--	2.8	--
General and administrative expenses	9.3	6.5	5.4	4.8	3.2
Operating income (loss)	20.6	32.8	3.5	(45.4)	(10.0)
Interest income	0.7	0.1	--	0.3	0.5
Interest expense	(8.9)	(11.0)	(13.5)	(13.3)	(10.6)
Income (loss) before income taxes	(12.4)	21.9	(10.0)	(58.4)	(20.2)
Provision for income taxes	--	--	--	--	--
Net income (loss)	$(12.4)	$21.9	$(10.0)	$(58.4)	$(20.2)
CAPITAL EXPENDITURE AND DISPOSAL DATA:					
Exploration, including leasehold/seismic	$66.3	$46.7	$24.0	$78.8	$49.0
Development and other	98.2	61.4	57.5	63.1	19.9
Proceeds from property conveyances	(90.5)	(29.0)	(19.8)	--	--
Total capital expenditures net of proceeds from property conveyances	$74.0	$79.1	$61.7	$141.9	$68.9
BALANCE SHEET DATA (AT END OF PERIOD):					
Oil and gas properties, net, at full cost	$290.6	$287.8	$263.6	$233.3	$175.7
Total assets	363.9	335.4	297.5	262.3	212.6

(All amounts in millions)					
Long-term debt, less current maturities	99.8	129.7	167.3	124.6	113.6
Stockholder's equity	180.1	141.9	65.0	27.5	57.2

1. Historically we have recorded all derivative transactions utilizing hedge accounting treatment. On January 1, 2001 we adopted Financial Accounting Standard No. 133 Accounting for Derivative Instruments and Hedging Activities . In addition, beginning on December 2, 2001, due to the Enron bankruptcy, we ceased hedging accounting treatment.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

(a) Introduction

The following discussion is intended to assist in an understanding of our financial position and results of operations for each of the three years in the period that began January 1, 1999 and ended December 31, 2001. This discussion should be read in conjunction with the information contained in the financial statements included elsewhere in this annual report. All statements other than statements of historical fact included in this annual report, including, without limitation, statements contained in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" regarding our financial position, business strategy, plans and objectives of management for future operations and industry conditions, are forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct.

(b) General

We are an independent oil and natural gas exploration, development and production company with principal operations in the Gulf and along the U.S. Gulf Coast. Our strategy is to profitably increase reserves, production and cash flow primarily through the drillbit.

During 2001 we:

- drilled eleven (11) exploratory wells, with seven (7) successes, in the Gulf of Mexico;
- drilled successful appraisal wells on our Aconcagua, King Kong, Crater Lake, Shasta, Swordfish and Roaring Fork prospects;
- completed a full year of production from our Black Widow project, which, when combined with production from other projects, resulted in the highest level of production in our history;
- sold our interest in Devils Tower and Aconcagua discoveries, with proceeds from these sales being used to pay off our Revolving Credit Facility;
- added proved reserves of 113.1 Bcfe, which were approximately 311% of our 2001 production of 36.7 Bcfe, excluding 47.2 Bcfe in dispositions of our Aconcagua and Devils Tower projects.

We anticipate capital expenditures for 2002, net of proceeds from property conveyances of $48.8 million, to be approximately $65.4 million for leasehold acquisition, exploration drilling and development projects, compared to our 2001 capital expenditures of approximately $74.0 million, net of proceeds from property conveyances of $90.5 million. We expect to fund our capital expenditures by a combination of internally generated cash flow, proceeds from property conveyances, including the recently announced sale of half of our remaining interest in the Falcon development project, and borrowings under our Revolving Credit Facility.

Our results of operations may vary significantly from year to year based on the factors discussed above and on other factors such as exploratory and development drilling success, curtailments of production due to workover and recompletion activities and the timing and amount of reimbursement for overhead costs we receive from co-owners. Therefore, the results of any one year may not be indicative of future results.

(c) Enron-Control Relationships and Related Party Transactions

Enron Bankruptcy - On December 2, 2001, Enron Corp. ("Enron") and one of its affiliates,Enron North America Corp. ("ENA"), among other affiliates filed voluntary petitions for bankruptcy protection. The Company has been informed that of the various affiliates of Enron to Mariner, only Enron and ENA are included in the bankruptcy. We do not know at this time if any other affiliates of Enron will seek bankruptcy protection or what effect, if any, this may have on Joint Energy Development Investments Limited Partnership ("JEDI") or the ownership of Mariner Energy LLC which owns 100% of our direct parent. Enron is the parent of ENA, and an affiliate of ENA is the general partner of JEDI. JEDI is 100% owned by several different Enron and ENA affiliates. Accordingly, Enron may be deemed to control JEDI, Mariner Energy LLC, Mariner Holdings and the Company. Additionally, seven of the Company's directors are officers of Enron or affiliates of Enron. Because of these various potentially conflicting interests, ENA, the Company, JEDI and the members of the Company's management who are also shareholders of Mariner Energy LLC have entered into an agreement that is intended to make clear that Enron and its affiliates have no duty to make business opportunities available to the Company.

Mariner Energy LLC's only asset is 100% of the common stock of Mariner Holdings, Inc., our direct parent. The only asset of Mariner Holdings is 100% of the common shares of Mariner. Covenants in Mariner's Revolving Credit Facility and Senior Subordinated Notes restrict the funds of Mariner that can be distributed to Mariner Energy LLC to repay its term loan to an ENA affiliate - see below "ENA Affiliate Term Loan". Mariner Energy LLC is currently attempting to obtain an extension of the ENA Affiliate Term Loan, but there can be no assurance that an extension will be obtained. In the event Mariner Energy LLC is unable to obtain an extension or restructure its obligations, it would either default or be forced to sell its interest in Mariner or cause Mariner to sell a substantial portion of its assets to repay its Revolving Credit Facility, if any amounts are outstanding, and outstanding Senior Subordinated Notes so that it could distribute any remaining cash proceeds to Mariner Energy LLC to be used to repay the ENA Affiliate Term Loan.

As a result of the Enron and ENA bankruptcies, among other implications, as part of our normal operations we may not be able to obtain credit from banks or trade vendors or enter into hedging arrangements on acceptable terms. This may also hinder our ability to enter into certain transactions including purchase or sale arrangements and conduct significant capital programs.

Organization and Ownership of the Company - Through March 31, 1996, Hardy Oil & Gas USA Inc. (the "Predecessor Company") was a wholly-owned subsidiary of Hardy Holdings Inc., which is a wholly-owned subsidiary of Hardy Oil & Gas Plc ("Hardy Plc"), a company incorporated in the United Kingdom. Pursuant to a stock purchase agreement dated April 1, 1996, JEDI and ENA, together with members of management of the Predecessor Company, formed Mariner Holdings, Inc. ("Mariner Holdings"). Mariner Holdings then purchased from Hardy Holdings Inc. all of the issued and outstanding stock of the Predecessor Company for a purchase price of approximately $185.5 million (the "Acquisition"). After the Acquisition, the name of the Predecessor Company was changed to Mariner Energy, Inc. In October 1998, JEDI and other shareholders exchanged all of their common shares of Mariner Holdings, the Company's direct parent, for an equivalent ownership percentage in common shares of Mariner Energy LLC. Mariner Energy LLC owns 100% of Mariner Holdings.

The following chart represents our current ownership structure and affiliation with Enron entities.

Subsequent to the Acquisition, Mariner Energy LLC, Mariner Holdings and Mariner have each entered into various financing and operating transactions with affiliates. In addition the Company may have from time to time engaged in various commercial transactions and have various commercial relationships with Enron and certain affiliates of Enron, such as holding and exploring, exploiting and developing joint working interests in particular prospects and properties and entering into other oil and gas related or financial transactions. Certain of the Company's third-party debt instruments and arrangements restrict the Company's ability to engage in transactions with its affiliates, but those restrictions are subject to significant exceptions. The Company believes that its current agreements with Enron and its affiliates are, and anticipates that any future agreements with Enron and its affiliates will be, on terms no less favorable to the Company than would be obtained in an agreement with a third party. Below is a summary of key transactions between the Company and affiliate entities.

Mariner Energy LLC

ENA Credit Facility - In September 1998 Mariner Holdings established a credit facility to obtain additional capital. The credit facility, as subsequently amended and assigned to Mariner Energy LLC, provided for unsecured, subordinated loans of up to $50 million, bearing interest at LIBOR plus 4.5%, payable at April 30, 2000. The full amount borrowed under this credit facility was repaid on March 21, 2000 with proceeds from the ENA Affiliate Term Loan described below. The net proceeds from this facility were contributed to Mariner.

ENA Affiliate Term Loan - In March 2000, Mariner Energy LLC established an unsecured term loan with ENA to repay amounts outstanding under the ENA Credit Facility with Mariner Energy LLC ($50 million plus accrued interest) described above and Mariner's Senior Credit Facility with ENA ($25 million plus accrued interest), described below, and to provide additional working capital. The additional working capital of $55 million was contributed to Mariner in 2000. The loan bears interest at 15%, which interest accrues and is added to the loan principal. Repayment of the balance of loan principal and accrued interest, which was approximately $143 million as of December 31, 2001, is due March 20, 2003. As part of the loan agreement, two five-year warrants were issued to ENA providing the right to purchase up to 900,000 of common shares of Mariner Energy LLC for $0.01 per share.

We have been informed that the Term Loan was transferred from ENA to an ENA affiliate.

Mariner Holdings, Inc.

1998 Equity Investment - In June 1998, Mariner Holdings issued additional equity to its existing shareholders, including JEDI, for approximately $14.58 per share, for a net investment of $28.8 million, all of which was contributed to Mariner. Mariner Holdings paid approximately $1.2 million as a structuring fee, on a pro rata basis, to existing shareholders participating in this transaction. Approximately $1 million of this fee was paid to ECT Securities Limited Partnership.

Mariner Energy, Inc.

Senior Credit Facility with ENA - In April 1999 Mariner established a senior credit facility with ENA primarily to obtain additional working capital. The facility provided for senior unsecured revolving loans of up to $25 million, bearing interest at LIBOR plus 2.5%, payable quarterly. The full amount borrowed under the senior credit facility was repaid on March 21, 2000, with proceeds from the ENA Affiliate Term Loan described above.

Other Transactions

Oil and Gas Production Sales to ENA or Affiliates - During the three years ending December 31, 2001, 2000 and 1999, sales of oil and gas production to ENA or affiliates were $50.2 million, $73.4 million and $16.2 million, respectively. These sales were generally made on 1 to 3 month contracts. At the time ENA filed its petition for bankruptcy protection, the Company immediately ceased selling its physical production to ENA. As of December 31, 2001, we had an outstanding receivable for $3.0 million from ENA. This amount was not paid as scheduled and is still outstanding. The Company has estimated 90% of this balance is uncollectible and has recorded an allowance and related expense for $2.7 million.

Accounting for Price Risk Management Activities - Mariner engages in price risk management activities from time to time. These activities are intended to manage Mariner's exposure to fluctuations in commodity prices for natural gas and crude oil. The Company primarily utilizes price swaps and costless collars as a means to manage such risk. During 2001 and as of December 31, 2001, all of our hedging contracts were with ENA. As a result of ENA's bankruptcy, the contracts are currently in default. The November and December settlements for oil and gas have not been collected, and there is significant uncertainty that the $4.0 million owed to the Company for the November and December settlements or any future settlements will be collected. As a result of the default, the Company has recorded an allowance representing 90% of the recorded hedge settlements receivable of $4.0 million, fair market value of the derivative assets of $25.8 (as of December 2, 2001), and accounts receivable for oil and gas sales of $3.0 million. Reflected in the earnings of the Company for the period ended December 31, 2001 is a loss for impairment of Enron related receivables of $29.5 million. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137 and No. 138, we have de designated our contracts effective December 2, 2001 and are recognizing all market value changes subsequent to such de-designation in earnings of the Company. The value recorded up to the time of de-designation and included in Accumulated Other Comprehensive Income ("AOCI"), will reverse out of AOCI and into earnings as the original corresponding production, as hedged by the contracts, is produced. As of December 31, 2001, $25.8 million remained in AOCI to be reversed out during the contract periods covering January 1, 2002 through December 31, 2003. Due to the uncertainty of future settlements, the overall effect of the ENA bankruptcy has been to eliminate our commodity price hedge protection.

The following table sets forth the results of hedging transactions during the periods indicated. For the year ended December 31, 2001, the amounts are reflective of the results up to the point of de-designation (December 2, 2001), which include all settled contract months through December of 2001:

The following table sets forth the results of hedging transactions during the periods indicated:

	YEAR ENDING DECEMBER 31,		
	2001	**2000**	**1999**
Natural gas quantity hedged (Mmbtu)	17,733	19,569	18,818
Increase (decrease) in natural gas sales (thousands)	$(5,523)	($21,364)	($6,741)
Crude oil quantity hedged (MBbls)	752	1,059	389
Increase (decrease) in crude oil sales (thousands)	$2,393	($14,053)	($2,152)

The following table sets forth our open positions as of December 31, 2001.

TIME PERIOD	NOTIONAL QUANTITIES	FIXED PRICE	FAIR VALUE (in millions)
NATURAL GAS (MMBTU)			
January 1 - October 31, 2002			
Fixed price swap purchased	1,831	$2.18	$(0.9)
January 1 - December 31, 2002			
Fixed price swap purchased	12,134	4.43	20.4
April 1 - December 31, 2002			
Fixed price swap purchased	4,125	3.03	0.9
January 1 - December 31, 2003			
Fixed price swap purchased	3,650	3.74	2.0
CRUDE OIL (MBBL)			
January 1 - June 30, 2002			
Fixed price swap purchased	181	25.15	0.9
January 1 - December 31, 2002			
Fixed price swap purchased	365	25.48	1.9
Sub-Total			$25.2(1)
Allowance for impairment			$(22.7)
Total			$2.5

1. Subsequent to the date of default by Enron and ENA, and as of December 31, 2001, the contracts decreased in gross market value by $523,000, which is reflected in the impairment of related party receivables at the net valuation of 10% or $52,000, after consideration for allowance.

Transportation Contract - In 1999 the Company constructed a 29 mile flowline from a third party platform to the Mississippi Canyon 718 subsea well. After commissioning, MEGS LLC, an Enron affiliate that is not in bankruptcy, purchased the flowline from the Company and its joint interest partners. The Company received $8.8 million in cash proceeds that were offset against the cost of constructing the flowline. No gain or loss was recognized. In addition, the Company entered into a firm transportation contract with MEGS LLC at a rate of $0.26 per Mmbtu to transport the Company's share of 86 Bcf of natural gas from the commencement of production through March 2009. The Company's working interest in the well at December 31, 2001 was 51%. For the year ending December 31, 2001, the Company paid $4.2 million on this contract. The remaining volume commitment is 30.8 Bbtu or $7.9 million net to the Company. Pursuant to the contract, the Company must deliver minimum quantities through the flowline or be subject to minimum monthly payment requirements. Throughout 2001 the Company failed to meet these minimum requirements and paid $1.5 million relating to the shortfall. The Company estimates that future production will also fail to meet minimum delivery requirements and has accrued $972,000 for future shortfalls.

Services Agreement - In conjunction with the change of certain key management positions, the Company entered into a services agreement for ENA to provide certain administrative services. The Company is obligated to pay $45,000 per month under this agreement.

Supplemental Affiliate Data - Provided below is supplemental balance sheet and income statement amounts for affiliate entities:

	YEAR ENDED DECEMBER 31,			
	2001		2000	
BALANCE SHEET DATA	**AMOUNTS (in millions)**		**AMOUNTS (in millions)**	
RELATED PARTY RECEIVABLE:				
Derivative Asset	$2.5			
Settled Hedge Receivable	0.4			
Oil and Gas Receivable	0.3	$3.2	$6.9	$6.9
ACCURED LIABILITIES:				
Transportation Contract	$0.9		--	
Service Agreement	$0.3	$1.2	--	--
STOCKHOLDERS' EQUITY:				
Common Stock	$0.001		$0.001	
Additional Paid-in Capital	$227.3	$227.3	$227.3	$227.3
INCOME STATEMENT DATA				
Oil and Gas Sales	$50.2		$73.4	
General and Administrative Expenses	0.2		--	
Transportation Expenses	4.2		3.7	
Impairment of Enron Related Receivables	29.5		--	

(d) Risk Factors

Exploration Risks - In addition to the other information set forth elsewhere in this annual report, including the potential impact of the Enron bankruptcy matters, the following factors should be carefully considered when evaluating Mariner. Exploration is a high-risk activity, and the 3-D seismic data and other advanced technologies we use cannot eliminate exploration risk. In addition, use of these technologies requires experienced technical personnel who we may be unable to attract or retain.

Our future success will depend on the success of our exploratory drilling program. Exploration activities involve numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be discovered. In addition, we are often uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of the additional exploration time and expense associated with a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs or equipment.

Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. We could incur losses as a result of exploratory drilling expenditures. Poor results from exploration activities could affect future cash flows and results of operations materially and adversely.

Our exploratory drilling success will depend, in part, on our ability to attract and retain experienced explorationists and other professional personnel. Competition for explorationists and engineers with experience in the Gulf of Mexico is intense. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete in the Gulf of Mexico could be adversely affected.

Exploration for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico involves greater operational and financial risks than exploration at shallower depths and in shallower waters. These risks could result in substantial losses.

Prospect Development Risks - Our 2001 discoveries on East Breaks 579 ("Falcon"), Viosca Knoll 917 ("Swordfish") and South Timbalier ("Roaring Fork") have required and over the next two years will continue to require significant financial resources. We do not expect production from these discoveries to commence prior to 2003, but we must commit substantial resources in advance of the expected production date and cannot predict the price of oil if and when production commences.

Operative Risks - The natural gas and oil business involves a variety of operating risks, including fires, explosions, blow-outs and surface cratering, uncontrollable flows of underground natural gas, oil and formation water, natural disasters, pipe or cement failures, casing collapses, embedded oilfield drilling and service tools, abnormally pressured formations and environmental hazards such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases. If any of these events occur, we could incur substantial losses as a result of injury or loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of our operations and repairs to resume operations. If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be adversely affected, which in turn could adversely affect our ability to conduct operations.

Offshore operations are also subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties.

Production of reserves from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the world. This results in recovery of a relatively higher percentage of reserves from properties in the Gulf of Mexico during the initial few years of production. As a result, reserve replacement needs from new prospects are greater and require us to incur significant capital expenditures to replace production.

Financial Position Risks - For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect our operations.

As part of our strategy, we explore for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico, where operations are more difficult and costly than at shallower depths. Deep depth and deep water drilling and operations require the application of recently developed technologies that involve a higher risk of mechanical failure. We have experienced and will continue to experience significantly higher drilling costs for our deep depth and deepwater prospects. Furthermore, the deep waters of the Gulf of Mexico lack the physical and oilfield service infrastructure present in the shallower waters. As a result, a significant amount of time may elapse between a deep water discovery and our marketing of the associated natural gas or oil, increasing both the financial and operational risk involved with these operations.

Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under the Credit Facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that we can economically produce.

Conversely, our potential need to generate revenues to fund ongoing capital commitments or reduce indebtedness may limit our ability to slow or shut-in production from producing wells during periods of low prices for natural gas and oil.

Prices for natural gas and oil fluctuate widely. For example, natural gas prices declined significantly in 2001 from levels reached in the second half of 2000 and early 2001. Prices for natural gas and oil also declined significantly in 1998 and, for an extended period of time, remained substantially below prices obtained in previous years. Among the factors that can cause this fluctuation are the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions in natural gas and oil producing regions, the domestic and foreign supply of natural gas and oil, the price of foreign imports and overall economic conditions. If natural gas and oil prices decline, even if for only a short period of time, it is possible that write-downs of natural gas and oil properties could occur. While we attempt to partially minimize this risk through our hedging arrangements, hedging production has limited and may continue to limit potential gains from increases in commodity prices or result in losses.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These financial arrangements take the form of swap contracts or costless collars and are placed. The Company had in place both financial hedge and physical contracts with ENA at the time ENA filed for bankruptcy in

December 2001. We did not receive payment as required under these contracts. We cannot provide assurance that other trading counterparties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the other party to the hedging contract defaults on its contract obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements have limited and may continue to limit the benefit we could receive from increases in the prices for natural gas and oil. We cannot provide assurance that our hedging transactions will adequately protect us from fluctuations in natural gas and oil prices. We may choose not to engage in hedging transactions in the future. As a result, we may be adversely affected during periods of declining natural gas and oil prices.

We have experienced and expect to continue to experience substantial capital expenditure and working capital needs, particularly as a result of our drilling program. In the future, we expect we will require additional financing, in addition to cash generated from our operations, to fund our planned growth. We cannot be certain that additional financing will be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail our drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

We incurred net losses of $10.0 million, $58.4 million, and $20.2 million in 1999, 1998, and 1997, respectively. Our development of and participation in a larger number of prospects has required and will continue to require substantial capital expenditures. We cannot provide assurance that it will sustain profitability or positive cash flows from operating activities in the future. Our failure to sustain profitability in the future could adversely affect our company.

Concentration Risks - We are subject to risks associated with the Gulf of Mexico, where substantially all of our exploration activities and production are located. This concentration of activity makes us more vulnerable than many of our competitors to the risks associated with the Gulf of Mexico, including delays and increased costs relating to adverse weather conditions, drilling rig and other oilfield services and compliance with environmental and other laws and regulations.

A significant part of the value of our production and reserves is concentrated in a small number of offshore properties. Because of this concentration, any production problems or inaccuracies in reserve estimates related to those properties are more likely to adversely impact in our business. During 2001, over 62 percent of our production came from four properties in the Gulf of Mexico. If mechanical problems, storms or other events curtailed a substantial portion of this production, our cash flow would be adversely affected. In addition, at December 31, 2001 approximately 75 percent of the proved reserves was attributable to 9 properties. If the actual reserves associated with any one of these 9 properties are substantially less than the estimated reserves, our results of operations and financial condition could be adversely affected.

Industry Risks - Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete, and we may be adversely affected. For example, marine seismic acquisition technology has been characterized by rapid technological advancements in recent years and further significant technological developments could substantially impair the 3-D seismic data's value.

We compete with major and independent natural gas and oil companies for property acquisitions. We also compete for the equipment and labor required to operate and develop properties. Most of our competitors have substantially greater financial and other resources than we do. As a result, in the deep water where exploration is more expensive, competitors may be better able to withstand sustained periods of unsuccessful drilling. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of our competitors have been operating in the Gulf of Mexico for a much longer time than we have and have demonstrated the ability to operate through industry cycles.

Other companies operate some of the properties in which we have an interest. As a result, we have a limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities. The success and timing of drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of our control, including timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells and selection of technology.

Reserve Risks - The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and net present value of reserves.

In order to prepare these estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of natural gas and oil reserves are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control. At December 31, 2001, approximately 74 percent of our proved reserves were either proved undeveloped or proved non-producing. Moreover, some of the producing wells included in our reserve report had produced for a relatively short period of time as of December 31, 2001. Because most of the reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a lengthy production history.

It should not be assumed that the present value of future net cash flows from our proved reserves is the current market value of its estimated natural gas and oil reserves. In accordance with Securities and Exchange Commission requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate.

Our future natural gas and oil production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves, our level of production and cash flows could be adversely impacted. In general, production from natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. If we are not successful, our future production and revenues will be adversely affected.

Regulation Risks - We are subject to complex laws and regulations, including environmental regulations which can adversely affect the cost, manner or feasibility of doing business.

Exploration for and development, production and sale of natural gas and oil in the U.S. and especially in the Gulf of Mexico are subject to extensive federal, state and local laws and regulations, including environmental laws and regulations. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations and taxation.

Under these laws and regulations, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We do not believe that full insurance coverage for all potential environmental damages is available at a reasonable cost. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that substantially increase costs. For example, Congress or the MMS could decide to limit exploratory drilling or natural gas production in additional areas of the Gulf of Mexico. Accordingly, any of these liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our financial condition and results of operations.

(e) Critical Accounting Policies and Estimates

Our discussion and analysis of Mariner's financial condition and results of operation are based upon financial statements that have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 1 to our financial statements. In response to SEC Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," we have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates, including those related to oil and gas revenues, oil and gas properties, fair value of derivative instruments, income taxes and contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances.

Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our financial statements:

Oil and Gas Properties - Oil and gas properties are accounted for using the full-cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and gas properties are capitalized. Amortization of oil and gas properties is provided using the unit-of-production method based on estimated proved oil and gas reserves. No gains or losses are recognized upon the sale or disposition of oil and gas properties unless the sale or disposition represents a significant quantity of oil and gas reserves. The net carrying value of proved oil and gas properties is limited to an estimate of the future net revenues (discounted at 10%) from proved oil and gas reserves based on period-end prices and costs plus the lower of cost or estimated fair value of unproved properties. As a result of this limitation, based on year-end prices of $2.65 per Mcf of natural gas and $19.43 per Bbl of crude oil, a permanent impairment of oil and gas properties of approximately $37.8 million would be required as of December 31, 2001. However as allowed by the Securities and Exchange Commission guidelines since both natural gas and crude oil prices have significantly increased since year-end, no writedown was required as of December 31, 2001.

The costs of unproved properties are excluded from amortization using the full-cost method of accounting. These costs are assessed quarterly for possible impairments or reduction in value based on geological and geophysical data. If a reduction in value has occurred, costs being amortized are increased. The majority of the costs will be evaluated over the next three years.

Capitalized Interest Costs - The Company capitalizes interest based on the cost of major development projects which are excluded from current depreciation, depletion, and amortization calculations. Capitalized interest costs were approximately $2,836,000, $3,885,000, and $3,028,000 for the years ended December 31, 2001, 2000 and 1999, respectively.

Accrual for Future Abandonment Costs - Provision is made for abandonment costs calculated on a unit-of-production basis, representing the Company's estimated liability at current prices for costs which may be incurred in the removal and abandonment of production facilities at the end of the producing life of each property.

Hedging Program - The Company utilizes derivative instruments in the form of natural gas and crude oil price swap and price collar agreements in order to manage price risk associated with future crude oil and natural gas production and fixed-price crude oil and natural gas purchase and sale commitments. Such agreements are accounted for as hedges using the deferral method of accounting. Gains and losses resulting from these transactions, recorded at market value are deferred, and recorded in Accumulated Other Comprehensive Income ("AOCI") as appropriate, until recognized as operating income in the Company's Statement of Operations as the physical production hedged by the contracts is delivered.

The net cash flows related to any recognized gains or losses associated with these hedges are reported as oil and gas revenues and presented in cash flows from operations. If the hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period as the physical production hedged by the contracts is delivered.

The conditions to be met for a derivative instrument to qualify as a cash hedge are the following: (i) the item to be hedged exposes the Company to price risk; (ii) the derivative reduces the risk exposure and is designated as a hedge at the time the derivative contract is entered into; and (iii) at the inception of the hedge and throughout the hedge period there is a high correlation of changes in the market value of the derivative instrument and the fair value of the underlying item being hedged.

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are recognized as part of the gain or loss on sale or settlement of the underlying item. When a derivative instrument is associated with an anticipated transaction that is no longer expected to occur or if correlation no longer exists, the gain or loss on the derivative is recognized in income to the extent the future results have not been offset by the effects of price or interest rate changes on the hedged item since the inception of the hedge.

Financial Instruments - The Company's financial instruments consist of cash and cash equivalents, receivables, payables, and debt. At December 31, 2001 and 2000, the estimated fair value of the Company's $100,000,000 Senior Subordinated Notes was approximately $95,000,000 and $91,000,000, respectively. The estimated fair value was determined based on borrowing rates available at December 31, 2001 and 2000, respectively, for debt with similar terms and maturities. The carrying amount of the Company's other instruments noted above approximate fair value.

Major Customers - During the year ended December 31, 2001, sales of oil and gas to three purchasers, including an Enron affiliate, accounted for 32%, 24% and 14% of total revenues. During the year ended December 31, 2000, sales of oil and gas to two purchasers, including an affiliate, accounted for 49% and 16% of total revenues. During the year ended December 31, 1999, sales of oil and gas to three purchasers accounted for 26%, 21% and 13% of total revenues. Management believes that the loss of any of these purchasers would not have a material impact on the Company's financial condition or results of operations.

(f) Results of Operations

The following table repeats certain operating information found in Item 2. Of this report with respect to oil and natural gas production, average sales price received and expenses per unit of production during the periods indicated.

	Year Ending December 31,		
	2001	2000	1999
PRODUCTION:			
Oil (MMbbls)	3.0	1.8	0.6
Natural gas (Bcf)	18.8	25.7	21.1
Natural Gas equivalent ((Bcfe)	36.7	36.3	24.9
AVERAGE REALIZED SALES PRICE (EXCLUDING EFFECTS OF HEDGING):			
Oil ($/Bbl)	$22.41	$29.53	$17.53
Natural gas ($/Mcf)	4.86	4.07	2.48
Natural Gas equivalent ($/Mcfe)	4.31	4.32	2.58
AVERAGE REALIZED SALES PRICE (INCLUDING EFFECTS OF HEDGING):			
Oil ($/Bbl)	$23.22	$21.54	$14.11
Natural gas ($/Mcf)	4.57	3.24	2.16
Natural Gas equivalent ($/Mcfe)	4.22	3.24	2.19
EXPENSES ($/MCFE):			
Lease operating	$0.55	$0.47	$0.46
Transportation	0.33	0.22	0.08
General and administrative, net	0.25	0.18	0.22
Depreciation, depletion and amortization (excluding impairments)	1.73	1.57	1.29

(i) 2001 compared to 2000

Net production increased during 2001 to 36.7 billion cubic feet of natural gas equivalent (Bcfe) from 36.3 Bcfe in 2000, a 1% improvement. Production from a full year of our Black Widow project more than offset production declines in our other fields, primarily the Sandy Lake field, located onshore, and the Dulcimer and Apia fields, located offshore.

Hedging activities in 2001 (before de-designation due to the impact of the ENA bankruptcy) decreased our average realized natural gas price received by $0.29 per Mcf and revenues by $5.5 million, compared with a decrease of $0.83 per Mcf and revenues of $21.4 million in 2000. Our hedging activities with respect to crude oil during 2001 increased the average sales price received by $0.81 per Bbl and revenues by $2.4 million compared with a decrease of $7.99 per Bbl and revenues of $14.3 million.

Oil and gas revenues increased 28% to $155.0 million for 2001 from $121.1 million for 2000, due to a 26% increase in realized prices to $4.22 per Mcfe in 2001 from $3.34 per Mcfe in 2000.

Lease operating expenses increased 17% to $20.1 million for 2001 from $17.2 million for 2000 due to the higher production costs associated with our Black Widow project.

Transportation expenses increased 54% to $12.0 million for 2001 from $7.8 million for 2000. The increase was attributable to a full year's transportation expenses on Black Widow as well as mandatory minimum transportation charges on our Pluto project.

Depreciation, depletion, and amortization expense increased 12% to $63.5 million for 2001 from $56.8 million for 2000 as a result of the increase in the unit-of-production depreciation, depletion and amortization rate to $1.73 per Mcfe from $1.57 per Mcfe.

Impairment of Enron related receivables of $29.5 million was taken as a result of ENA filing a petition for bankruptcy protection (also see "Enron"). The allowance represents an 90% allowance on $7.0 million of settled physical and hedge contracts through December 31, 2001 and an 90% allowance on $25.3 million of hedge contracts marked to market value.

General and administrative expenses, which are net of overhead reimbursements we received from other working interest owners, increased 42% to $9.3 million for 2001 from $6.5 million for 2000 due to severance payments made as part of the change in key management as well as administrative reductions.

Net interest expense for 2001 decreased 25% to $8.2 million from $10.9 million for 2000, primarily due to reduced debt levels allowed by our sale of certain oil and gas properties.

Income (loss) before income taxes decreased to a net income of $12.4 million for 2001 from $21.9 million in 2000, primarily as a result of increased revenue offset in part by increased expenses discussed above.

(ii) 2000 compared to 1999

Net production increased 46% to 36.3 Bcfe for 2000 from 24.9 Bcfe for 1999. Production from our offshore Gulf properties increased to 18.2 Bcfe in 1999 from 13.1 Bcfe in 1998, as a result of production commencing from a new well in the Dulcimer field located in Garden Banks block 367 and two new wells in the Rembrandt field located in Galveston block 151. This increase was offset by less than expected production from our Sandy Lake field onshore Texas.

Hedging activities in 2000 decreased our average realized natural gas price received by $0.83 per Mcf and revenues by $21.4 million, compared with a decrease of $0.32 per Mcf and revenues of $6.7 million in 1999. Our hedging activities with respect to crude oil during 2000 reduced the average sales price received by $7.97 per Bbl and revenues by $14.1 million compared with a decrease of $3.42 per Bbl and revenues by $2.2 million in 1999.

Oil and gas revenues increased 122% to $121.1 million for 2000 from $54.5 million for 1999, due to a 34% increase in realized prices to $3.34 per Mcfe in 2000 from $2.19 per Mcfe in 1999.

Lease operating expenses increased 50% to $17.2 million for 2000 from $11.5 million for 1999 due to the higher offshore production discussed above and well workovers on three offshore wells and two wells in our Sandy Lake field.

Transportation expenses increased 290% to $7.8 million for 2000 from $2.0 million for 1999. The increase was attributable to the addition of additional production on offshore properties that are subject to transportation tarriffs.

Depreciation, depletion, and amortization expense increased 77% to $56.8 million for 2000 from $32.1 million for 1999 as a result of the increase in the unit-of-production depreciation, depletion and amortization rate to $1.57 per Mcfe from $1.29 per Mcfe.

General and administrative expenses, which are net of overhead reimbursements we received from other working interest owners, increased 22% to $6.6 million for 2000 from $5.4 million for 1999 due to increased personnel-related costs in 1999 required for us to pursue our deepwater Gulf exploration and development plan.

Net interest expense for 2000 decreased 19% to $11.0 million from $13.5 million for 1999.

Income (loss) before income taxes increased 119% to $21.9 million for 2000 from a loss of $10.0 million in 1999 as a result of the items discussed above.

(g) Liquidity and Capital Resources

(i) Cash Flows and Liquidity

As of December 31, 2001, we had a working capital deficit of approximately $19.6 million, compared to a working capital deficit of $15.4 million at December 31, 2000. The increase in the working capital deficit was primarily a result of higher accounts payable attributable to work being performed on our King Kong / Yosemite and Crater Lake projects in progress at year end. We expect our 2002 capital expenditures, excluding capitalized general and administrative, interest costs and proceeds from property conveyances, to be approximately $65.5 million, which is lower than budgeted cash flow from operations. There can be no assurance that actual cash flow from operations will exceed capital expenditures or that our access to capital will be sufficient to meet our needs for capital. Accordingly, we may be required to reduce our planned capital expenditures and forego planned exploratory drilling (see "Recent Events" regarding the April 2002 sale with proceeds of $48.8 million).

Our Revolving Credit Facility matures in October 2002. We expect to begin renegotiation of our agreement with existing banks that provide the facility during the first half of 2002. We plan to minimize the use of the facility until such time as this agreement can be renegotiated or replaced with a similar agreement. There is no assurance that this agreement can be renegotiated or replaced. In addition our parent, Mariner Energy LLC, is currently obligated under a three-year unsecured term loan with an ENA affiliate, which matures in March 2003. Currently we expect to attempt to obtain an extension on this agreement. In the event Mariner Energy, LLC is unable to obtain an extension or restructure its obligation, Mariner Energy LLC would either default or be forced to sell its interest in Mariner Energy, Inc., or cause Mariner to sell a substantial portion of its assets to repay its Revolving Credit Facility and outstanding Senior Subordinated Notes to that it could distribute cash to Mariner Energy LLC to be used to repay the term loan. In the event either a change of control occurs of our company or a sale of a substantial portion of our assets, both the balances outstanding under the Senior Subordinated Notes and Revolving Credit Facility would have to be repaid prior to payment of the term loan. Although we believe we will be successful in extending the term loan, there can be no assurance that an extension will be obtained.

We had a net cash inflow of $9.5 million in 2001, compared to a net cash inflow of $2.3 million in 2000 and a net cash outflow of $0.1 million in 1999. A discussion of the major components of cash flows for these years follows.

	2001	2000	1999
Cash flows provided by operating activities (in millions)	$113.6	$63.9	$24.4

Cash flows provided by operating activities in 2001 increased by $49.6 million compared to 2000 due to increased oil and gas prices, offset in part by higher production lease operating and general and administrative expenses. Cash flows from operating activities in 2000 increased by $39.5 million from 1999 primarily due to increased oil and gas prices, production lease operating and general and administrative expenses.

	2001	2000	1999
Cash flows used in investing activities (in millions)	$74.0	$79.1	$61.8

Cash flows used in investing activities in 2001 decreased by $5.1 million compared to 2000 due to increased capital expenditures offset by $90.5 million in proceeds from property conveyances. Cash flows used in investing activities in 2000 increased by $17.3 million compared to 1999 increased capital expenditures offset by $29.0 million in proceeds from property conveyances.

	2001	2000	1999
Cash flows provided by financing activities (in millions)	$(30.0)	$17.4	$37.5

Cash flows provided by financing activities in 2001 decreased by $47.4 million compared to 2000 due to a $30 million net reduction in borrowings against our Revolving Credit Facility. This reduction in our Revolving Credit Facility was attributable to repayments using proceeds from property conveyances mentioned above. Cash flows provided by financing activities in 2000 decreased by $20.1 million as compared to 1999 due to a $37.6 million net reduction in borrowings against our Revolving Credit Facility and our Affiliate Credit Facility as compared to a $14.2 million increase in borrowings against that facility for the previous year. In addition, capital contributions resulting from the sale of stock to Mariner Energy LLC increased by $31.7 million.

(ii) Changes in Prices and Hedging Activities

The energy markets have historically been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. In an effort to reduce the effects of the volatility of the price of oil and natural gas on our operations, management has adopted a policy of hedging oil and natural gas prices from time to time primarily through the use of commodity swap and costless collar agreements. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. All hedge activities historically have been conducted with Enron. As a result of the Enron bankruptcy we have de-designated all hedge positions (see "Enron").

Our Senior Subordinated Notes bear interest at a fixed rate and, therefore, do not expose us to risk of earnings loss due to changes in market interest rates. However, we are subject to interest rate risk under our Revolving Credit Facility and our short-term credit facility with ENA. For example, a 100 basis point increase in the London Interbank Offered Rate would have increased our 2001 interest expense by $0.1 million. The carrying value of our Revolving Credit Facility approximates market since these instruments have floating interest rates. The market value of the Senior Subordinated Notes was approximately $95.0 million based on borrowing rates available at December 31, 2001.

(iii) Capital Expenditures and Capital Resources

Capital expenditures and capital resources

The following table presents major components of our capital and exploration expenditures for each of the three years in the period ended December 31, 2001.

YEAR ENDING DECEMBER 31,

	YEAR ENDING DECEMBER 31,		
	2001	2000	1999
Capital expenditures (in millions):			
Leasehold acquisition	$8.8	$14.0	$14.9
Oil and natural gas exploration	57.5	17.2	13.8
Oil and natural gas development and other	98.2	76.9	52.8
Proceeds from property conveyances	(90.5)	(29.0)	(19.8)
Total capital expenditures, net of proceeds from property conveyances	$74.0	$79.1	$61.7

Our capital expenditures for 2001 were $74.0 million, including the $90.5 million of proceeds from property conveyances, which was $5.1 million less than 2000. The decrease was primarily a result of higher property conveyance proceeds offset in part by higher leasehold acquisition, geological and geophysical, and development expenditures.

Our capital expenditures for 2000 were $79.1 million, excluding the $29.0 million of proceeds from property conveyances, which was $17.4 million more than 1999. The increase was primarily a result of higher exploratory expenditures and development costs as we operated with increased access to capital.

Our approved capital expenditure budget for 2002 is approximately $65.4 million after estimated proceeds from property conveyances. Our budget includes approximately $50 million for exploration activities, $64.2 million for development activities and $48.8 million in proceeds from property conveyances. An active Gulf exploration program is underway, with funds budgeted to drill seven to ten wells. The exploration budget also anticipates additions to our 3-D seismic database and our leasehold position. The development budget includes funds for completion of our King Kong / Yosemite, Crater Lake, Falcon, Roaring Fork and Swordfish projects and several development wells in currently-producing fields.

Our long-term debt outstanding as of December 31, 2001 was approximately $99.8 million, comprised entirely of Senior Subordinated Notes. Following our semi-annual borrowing base redetermination which is expected to be completed in April 2002, our borrowing base under the Revolving Credit Facility is expected to be $45 million. This Revolving Credit Facility is due to mature in October 2002.

Our Revolving Credit Facility and the Senior Subordinated Notes contain various restrictive covenants that, among other things, restrict the payment of dividends, limit the amount of debt we may incur, limit our ability to make certain loans, investments, enter into transactions with affiliates, sell assets, enter into mergers, limit our ability to enter into certain hedge transactions and provide that we must maintain specified relationships between cash flow and fixed charges and cash flow and interest on indebtedness.

We expect to fund our activities for 2002 through a combination of cash flow from operations, borrowings under our Revolving Credit Facility, and proceeds from property conveyances. Our capital resources may not be sufficient to meet our anticipated future requirements for working capital, capital expenditures and scheduled payments of principal and interest on our indebtedness. In addition, depending on the levels of our cash flow and capital expenditures, we may need to refinance a portion of the principal amount of our senior subordinated debt at or prior to maturity. However, we cannot be certain that we will be able to obtain financing on acceptable terms to complete a refinancing.

(h) Recent Events

On March 20, 2002, with bids totaling $10.9 million net to us, we were the apparent high bidder solely or with industry partners, on 12 out of 16 blocks on which we and our partners submitted bids in the Central Gulf of Mexico Oil and Gas Lease Sale 182 held on that date. Each of the blocks is in water depths ranging from approximately 20 feet to 2,400 feet. Mariner has a 100% working interest in four of the blocks, 50% working interest in seven blocks and 20% working interest in one block.

In April 2002, we sold 50% of our working interest in our Falcon discovery and surrounding blocks, located in East Breaks Block 579 in the western Gulf of Mexico, for $48.8 million. Subsequent to the sale we have a 25% working interest in the discovery and surrounding blocks. The project is currently expected to begin production in the first quarter of 2003. At December 31, 2001, the Falcon project had 66.8 Bcfe assigned as proven reserves.

The net carrying value of our proved oil and gas properties is limited to an estimate of the future net revenues (discounted at 10%) from proved oil and gas reserves based on period-end prices and costs plus the lower of cost or estimated fair value of unproved properties. As a result of this limitation, based on year-end prices of $2.65 per Mcf of natural gas and $19.43 per Bbl of crude oil, an impairment of oil and gas properties of approximately $37.8 million would be required as of December 31, 2001. However, as allowed by the Securities and Exchange Commission guidelines, since both natural gas and crude oil prices have significantly increased since year-end, no writedown was required as of December 31, 2001.

(i) Contractual Commitments

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments . The following table summarizes these commitments at December 31, 2001 (in millions):

	2002	2003	2004	2005	2006	BEYOND 2006
DEBT AND OTHER OBLIGATIONS	$--	$--	$--	$--	$100	$--
OPERATING LEASES	1.5	0.7	0.1	--	--	--
TRANSPORTATION EXPENSES	2.5	1.7	1.2	0.9	0.7	0.9
OTHER COMMITMENTS	6.8	6.3	0.7	3.4	3.0	31.1
TOTAL CONTRACTUAL CASH COMMITMENTS	$10.8	$8.7	$2.0	$4.3	$103.7	$40.0

Other Commitments - In the ordinary course of business we enter into long-term commitments to purchase seismic data. The minimum annual payments under these contracts are $6.8 million in 2002, $6.3 million in 2003 and $2.7 million in 2004.

(j) Recent Accounting Pronouncements

In July 2001, the Financial Accounting Standards Board issued SFAS No. 141, "Business Combinations" (effective July 1, 2001) and SFAS No. 142, "Goodwill and Other Intangible Assets" (effective on January 1, 2002). SFAS No. 141 prohibits pooling-of-interests accounting for acquisitions. SFAS No. 142 specifies that goodwill and some intangible assets will no longer be amortized but instead will be subject to periodic impairment testing. We do not believe the adoption of these standards will have an impact on our financial statements.

In August and October 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" and SFAS No. 144, "Accounting for Impairment or Disposal of Long-Lived Assets". SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement costs should be allocated to expense using a systematic and rational method. SFAS 143 is effective for fiscal years beginning after June 15, 2002. SFAS 144 addresses financial accounting and reporting for the impairment of long-lived assets and for long-lived assets to be disposed of. It supersedes, with exceptions, SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of", and is effective for fiscal years beginning after December 15, 2001. The company is currently assessing the impact of SFAS No. 143 and No. 144 and therefore cannot reasonably estimate the impact, if any, these statements will have on its financial statements upon adoption.

Item 7A. Quantitative and Qualitative Disclosure about Market Risk

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - (d) (ii) Changes in Prices and Hedging Activities.

Item 8. Financial Statements and Supplmentary Data

Item 8. Financial Statements and Supplmentary Data

INDEX TO FINANCIAL STATEMENTS

	PAGE
Independent Auditors' Report	42
Balance Sheets at December 31, 2001 and 2000	43
Statements of Operations for the years ended December 31, 2001, 2000 and 1999	44
Statements of Stockholder's Equity for the years ended December 31, 2001, 2000 and 1999	45
Statements of Cash Flows for the years ended December 31, 2001, 2000 and 1999	46
Notes to Financial Statements	47

INDEPENDENT AUDITORS REPORT

Board of Directors and Stockholder
Mariner Energy, Inc.
Houston, Texas

We have audited the accompanying balance sheets of Mariner Energy, Inc. (the Company) as of December 31, 2001 and 2000 and the related statements of operations, stockholder s equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Mariner Energy, Inc. as of December 31, 2001 and 2000, and the results of its operations and cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles general accepted in the United States of America.

As described in Note 1, the Company changed its method of accounting for derivative instruments and hedging activities in accordance with Statement of Financial Accounting Standards No. 133 Accounting for Derivative Instruments and Hedging Activities .

As described in Note 2, the Company has various related-party transactions and certain control relationships with Enron Corp.

/s/ DELOITTE & TOUCHE LLP

DELOITTE & TOUCHE LLP

Houston, Texas
April 10, 2002

MARINER ENERGY, INC.
BALANCE SHEETS
(in thousands, except share data)

	Year Ended December 31,	
	2001	2000
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 11,838	$ 2,389
Receivables	34,122	33,534
Prepaid expenses and other	10,006	5,991
Total current assets	55,966	41,914
Property and Equipment:		
Oil and gas properties, at full cost:		
Proved	583,207	478,596
Unproved, not subject to amortization	29,341	61,068
Total	612,548	539,664
Other property and equipment	5,750	4,592
Accumulated depreciation, depletion and amortization	(316,567)	(254,396)
Total property and equipment, net	301,731	289,860
Other Assets, Net of Amortization	2,980	3,653
Long-Term Related Party Receivable	3,223	--
TOTAL ASSETS	$363,900	$335,427
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Accounts payable	$43,579	$ 37,600
Accrued liabilities	27,543	15,144
Accrued interest	4,469	4,522

MARINER ENERGY, INC.
BALANCE SHEETS
(in thousands, except share data)

Total current liabilities	75,591	57,266
Other Liabilities	8,454	6,552
Long-Term Debt:		
Senior Subordinated Notes	99,772	99,722
Revolving Credit Facility	--	30,000
Total long-term debt	99,772	129,722
Stockholder's Equity:		
Common stock, $1 par value; 2,000 and 1,000 shares authorized, 1,380 issued and outstanding, at December 31 2001 and December 31, 2000	1	1
Additional paid-in-capital	227,318	227,318
Accumulated other comprehensive income	25,803	--
Accumulated deficit	(73,039)	(85,432)
Total stockholder's equity	180,083	141,887
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$363,900	$335,427

The accompanying notes are an integral part of these financial statements

MARINER ENERGY, INC.
STATEMENTS OF OPERATIONS
(in thousands)

	Year Ending December 31,		
	2001	**2000**	**1999**
REVENUES:			
Oil sales	$69,145	$37,959	$8,888
Gas sales	85,855	83,191	45,597
Total revenues	155,000	121,150	54,485
COSTS AND EXPENSES:			

MARINER ENERGY, INC.
STATEMENTS OF OPERATIONS
(in thousands)

Lease operating expense	20,063	17,192	11,453
Transportation expense	12,011	7,789	2,017
General and administrative expense	9,274	6,549	5,396
Depreciation, depletion and amortization	63,503	56,846	32,121
Impairment of Enron related receivables	29,529	--	--
Total costs and expenses	134,380	88,376	50,987
OPERATING INCOME	20,620	32,774	3,498
INTEREST:			
Income	663	124	36
Expense	(8,890)	(11,037)	(13,504)
INCOME (LOSS) BEFORE TAXES	12,393	21,861	(9,970)
PROVISION FOR INCOME TAXES	--	--	--
NET INCOME (LOSS)	$12,393	$21,861	$(9,970)

The accompanying notes are an integral part of these financial statements

MARINER ENERGY, INC.
STATEMENTS OF STOCKHOLDER'S EQUITY
(in thousands, except number of shares)

	COMMON STOCK SHARES	COMMON STOCK AMOUNT	ADDITIONAL PAID-IN CAPITAL	ACCUMULATED OTHER COMPREHENSIVE INCOME	ACCUMULATED DEFICIT	TOTAL STOCKHOLDER'S EQUITY
BALANCE AT DECEMBER 31, 1998	1,000	$1	$124,856	--	$(97,323)	$27,534
Capital contribution	378	-	47,462	--	--	47,462
Net loss	--	-	--	--	(9,970)	(9,970)

MARINER ENERGY, INC.
STATEMENTS OF STOCKHOLDER'S EQUITY
(in thousands, except number of shares)

BALANCE AT DECEMBER 31, 1999	1,378	1	172,318	--	(107,293)	65,026
Capital contribution	2	-	55,000	--	--	55,000
Net income	--	-	--	--	21,861	21,861
BALANCE AT DECEMBER 31, 2000	1,380	1	$227,318	--	$(85,432)	$141,887
Net income	--				12,393	12,393
Cumulative effect of change in accounting principal	--	-	--	(32,976)	--	(32,976)
Change in fair value of derivative hedging investments	--	-	--	61,909	--	61,386
Hedge settlements reclassified to income	--	-	--	(3,130)	--	(3,130)
Total comprehensive income	--	-	--	--	--	38,196
BALANCE AT DECEMBER 31, 2001	1,380	$1	$227,318	$25,803	$(73,039)	$180,083

The accompanying notes are an integral part of these financial statements

MARINER ENERGY, INC.
STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ending December 31,		
	2001	**2000**	**1999**
OPERATING ACTIVITIES:			
Net income (loss)	$12,393	$21,861	$(9,970)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	64,118	57,538	32,838

MARINER ENERGY, INC.
STATEMENTS OF CASH FLOWS
(in thousands)

Impairment of Enron related receivables	29,529	--	--
Changes in operating assets and liabilities:			
Receivables	(1,041)	(9,851)	(8,119)
Other current assets	(4,015)	(1,100)	2,343
Other assets	(5,773)	(785)	265
Accounts payable and accrued liabilities	18,331	(3,721)	7,027
Net cash provided by operating activities	113,542	63,942	24,384
INVESTING ACTIVITIES:			
Additions to oil and gas properties	(163,385)	(107,468)	(80,823)
Proceeds from property conveyances	90,500	29,002	19,758
Additions to other property and equipment	(1,158)	(610)	(682)
Net cash used in investing activities	(74,043)	(79,076)	(61,747)
FINANCING ACTIVITIES:			
Repayment of revolving credit facility	(30,000)	(12,600)	(10,800)
Capital contributed by sale of stock to parent	--	55,000	23,284
Proceeds from (payments to) the affiliate credit facility	--	(25,000)	25,000
Net cash (used in) provided by financing activities	(30,000)	17,400	37,484
INCREASE IN CASH AND CASH EQUIVALENTS	9,449	2,266	121
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	2,389	123	2
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$11,838	$ 2,389	$ 123

The accompanying notes are an integral part of these financial statements

MARINER ENERGY, INC.
NOTES TO FINANCIAL STATEMENTS
For the Years Ended December 31, 2001, 2000 and 1999

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization - Through March 31, 1996, Hardy Oil & Gas USA Inc. (the "Predecessor Company") was a wholly owned subsidiary of Hardy Holdings Inc., which is a wholly owned subsidiary of Hardy Oil & Gas Plc ("Hardy Plc"), a company incorporated in the United Kingdom. Pursuant to a stock purchase agreement dated April 1, 1996, Joint Energy Development Investments Limited Partnership ("JEDI"), Enron North America Corp. ("ENA") (see "Note 2. Related-Party Transactions"), together with members of management of the Predecessor Company, formed Mariner Holdings, Inc. ("Mariner Holdings"), which then purchased from Hardy Holdings Inc. all of the issued and outstanding stock of the Predecessor Company for a purchase price of approximately $185.5 million effective April 1, 1996 for financial accounting purposes (the "Acquisition"). After the acquisition, the name of the predecessor company was changed to Mariner Energy, Inc. (the "Company"). The Company is primarily engaged in the exploration and exploitation for and development and production of oil and gas reserves, with principal operations both onshore and offshore Texas and Louisiana.

Exchange Offering - In October 1998, JEDI and other shareholders exchanged all of their common shares of Mariner Holdings, the Company's parent, for an equivalent ownership percentage in common shares of Mariner Energy LLC. As of December 31, 1999 Mariner Energy LLC owned 100% of Mariner Holdings.

Cash and Cash Equivalents - All short-term, highly liquid investments that have an original maturity date of three months or less are considered cash equivalents.

Receivables - Substantially all of the Company's receivables arise from sales of oil or natural gas, or from reimbursable expenses billed to the other participants in oil and gas wells for which the Company serves as operator.

Oil and Gas Properties - Oil and gas properties are accounted for using the full-cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and gas properties are capitalized. Amortization of oil and gas properties is provided using the unit-of-production method based on estimated proved oil and gas reserves. No gains or losses are recognized upon the sale or disposition of oil and gas properties unless the sale or disposition represents a significant quantity of oil and gas reserves. The net carrying value of proved oil and gas properties is limited to an estimate of the future net revenues (discounted at 10%) from proved oil and gas reserves based on period-end prices and costs plus the lower of cost or estimated fair value of unproved properties. As a result of this limitation, based on year-end prices of $2.65 per Mcf of natural gas and $19.43 per Bbl of crude oil, a permanent impairment of oil and gas properties of approximately $37.8 million would be required as of December 31, 2001. However as allowed by the Securities and Exchange Commission guidelines since both natural gas and crude oil prices have significantly increased since year-end, no writedown was required as of December 31, 2001.

The costs of unproved properties are excluded from amortization using the full-cost method of accounting. These costs are assessed quarterly for possible impairments or reduction in value based on geological and geophysical data. If a reduction in value has occurred, costs being amortized are increased. The majority of the costs will be evaluated over the next three years.

Other Property and Equipment - Depreciation of other property and equipment is provided on a straight-line basis over their estimated useful lives, which range from three to seven years.

Other Assets - Other assets are primarily deferred loans stated at cost subject to amortization over the life of the related debt. Accumulated amortization as of December 31, 2001 and 2000 was $5.6 million and $4.8 million, respectively.

Income Taxes - The Company's taxable income is included in a consolidated United States income tax return with Mariner Energy, LLC. The intercompany tax allocation policy provides that each member of the consolidated group compute a provision for income taxes on a separate return basis. The Company records its income taxes using an asset and liability approach which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax bases of assets and liabilities. Valuation allowances are established when necessary to reduce deferred tax assets to the amount more likely than not to be recovered.

Capitalized Interest Costs - The Company capitalizes interest based on the cost of major development projects which are excluded from current depreciation, depletion, and amortization calculations. Capitalized interest costs were approximately $2,836,000, $3,885,000, and $3,028,000 for the years ended December 31, 2001, 2000 and 1999, respectively.

Accrual for Future Abandonment Costs - Provision is made for abandonment costs calculated on a unit-of-production basis, representing the Company's estimated liability at current prices for costs which may be incurred in the removal and abandonment of production facilities at the end of the producing life of each property.

Hedging Program - The Company utilizes derivative instruments in the form of natural gas and crude oil price swap and price collar agreements in order to manage price risk associated with future crude oil and natural gas production and fixed-price crude oil and natural gas purchase and sale commitments. Such agreements are accounted for as hedges using the deferral method of accounting. Gains and losses resulting from these transactions, recorded at market value are deferred, and recorded in Accumulated Other Comprehensive Income ("AOCI") as appropriate, until recognized as operating income in the Company's Statement of Operations as the physical production hedged by the contracts is delivered.

The net cash flows related to any recognized gains or losses associated with these hedges are reported as oil and gas revenues and presented in cash flows from operations. If the hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period as the physical production hedged by the contracts is delivered.

The conditions to be met for a derivative instrument to qualify as a cash hedge are the following: (i) the item to be hedged exposes the Company to price risk; (ii) the derivative reduces the risk exposure and is designated as a hedge at the time the derivative contract is entered into; and (iii) at the inception of the hedge and throughout the hedge period there is a high correlation of changes in the market value of the derivative instrument and the fair value of the underlying item being hedged.

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are recognized as part of the gain or loss on sale or settlement of the underlying item. When a derivative instrument is associated with an anticipated transaction that is no longer expected to occur or if correlation no longer exists, the gain or loss on the derivative is recognized in income to the extent the future results have not been offset by the effects of price or interest rate changes on the hedged item since the inception of the hedge.

Revenue Recognition - The Company recognizes oil and gas revenue from its interests in producing wells as oil and gas from those wells is produced and sold. Oil and gas sold is not significantly different from the Company's share of production.

Financial Instruments - The Company's financial instruments consist of cash and cash equivalents, receivables, payables, and debt. At December 31, 2001 and 2000, the estimated fair value of the Company's $100,000,000 Senior Subordinated Notes was approximately $95,000,000 and $91,000,000, respectively. The estimated fair value was determined based on borrowing rates available at December 31, 2001 and 2000, respectively, for debt with similar terms and maturities. The carrying amount of the Company's other instruments noted above approximate fair value.

Use of Estimates in the Preparation of Financial Statements - The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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 amount of revenues and expenses during the reporting period. Actual results could differ from these estimates.

Major Customers - During the year ended December 31, 2001, sales of oil and gas to three purchasers, including an Enron affiliate, accounted for 31%, 24% and 14% of total revenues. During the year ended December 31, 2000, sales of oil and gas to two purchasers, including an affiliate, accounted for 49% and 16% of total revenues. During the year ended December 31, 1999, sales of oil and gas to three purchasers accounted for 26%, 21% and 13% of total revenues. Management believes that the loss of any of these purchasers would not have a material impact on the Company's financial condition or results of operations.

Reclassifications - Certain reclassifications were made to the prior years financial statements to conform to the current year presentation.

Recent Accounting Pronouncements - In July 2001, the Financial Accounting Standards Board issued SFAS No. 141, "Business Combinations" (effective July 1, 2001) and SFAS No. 142, "Goodwill and Other Intangible Assets" (effective on January 1, 2002). SFAS No. 141 prohibits pooling-of-interests accounting for acquisitions. SFAS No. 142 specifies that goodwill and some intangible assets will no longer be amortized but instead will be subject to periodic impairment testing. The Company does not believe the adoption of these statements will have an impact on its financial statements.

In August and October 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" and SFAS No. 144, "Accounting for Impairment or Disposal of Long-Lived Assets". SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement costs should be allocated to expense using a systematic and rational method. SFAS 143 is effective for fiscal years beginning after June 15, 2002. SFAS 144 addresses financial accounting and reporting for the impairment of long-lived assets and for long-lived assets to be disposed of. It supersedes, with exceptions, SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of", and is effective for fiscal years beginning after December 15, 2001. The Company is currently assessing the impact of SFAS No. 143 and No. 144 and therefore cannot reasonably estimate the impact, if any, these statements will have on its financial statements upon adoption.

2. RELATED-PARTY TRANSACTIONS

Enron Bankruptcy - On December 2, 2001, Enron Corp. ("Enron") and one of its affiliates,Enron North America Corp. ("ENA"), among other affiliates filed voluntary petitions for bankruptcy protection. The Company has been informed that of the various affiliates of Enron to Mariner, only Enron and ENA are included in the bankruptcy. We do not know at this time if any other affiliates of Enron will seek bankruptcy protection or what effect, if any, this may have on Joint Energy Development Investments Limited Partnership ("JEDI") or the ownership of Mariner Energy LLC which owns 100% of our direct parent. Enron is the parent of ENA, and an affiliate of ENA is the general partner of JEDI. JEDI is 100% owned by several different Enron and ENA affiliates. Accordingly, Enron may be deemed to control JEDI, Mariner Energy LLC, Mariner Holdings and the Company. Additionally, seven of the Company's directors are officers of Enron or affiliates of Enron. Because of these various potentially conflicting interests, ENA, the Company, JEDI and the members of the Company's management who are also shareholders of Mariner Energy LLC have entered into an agreement that is intended to make clear that Enron and its affiliates have no duty to make business opportunities available to the Company.

Mariner Energy LLC's only asset is 100% of the common stock of Mariner Holdings, Inc., our direct parent. The only asset of Mariner Holdings is 100% of the common shares of Mariner. Covenants in Mariner's Revolving Credit Facility and Senior Subordinated Notes restrict the funds of Mariner that can be distributed to Mariner Energy LLC to repay its term loan to an ENA affiliate - see below "ENA Affiliate Term Loan". Mariner Energy LLC is currently attempting to obtain an extension of the ENA Affiliate Term Loan, but there can be no assurance that an extension will be obtained. In the event Mariner Energy LLC is unable to obtain an extension or restructure its obligations, it would either default or be forced to sell its interest in Mariner or cause Mariner to sell a substantial portion of its assets to repay its Revolving Credit Facility, if any amounts are outstanding, and outstanding Senior Subordinated Notes so that it could distribute any remaining cash proceeds to Mariner Energy LLC to be used to repay the ENA Affiliate Term Loan.

As a result of the Enron and ENA bankruptcies, among other implications, as part of our normal operations we may not be able to obtain credit from banks or trade vendors or enter into hedging arrangements on acceptable terms. This may also hinder our ability to enter into certain transactions including purchase or sale arrangements and conduct significant capital programs.

Organization and Ownership of the Company - Through March 31, 1996, Hardy Oil & Gas USA Inc. (the "Predecessor Company") was a wholly-owned subsidiary of Hardy Holdings Inc., which is a wholly-owned subsidiary of Hardy Oil & Gas Plc ("Hardy Plc"), a company incorporated in the United Kingdom. Pursuant to a stock purchase agreement dated April 1, 1996, JEDI and ENA, together with members of management of the Predecessor Company, formed Mariner Holdings, Inc. ("Mariner Holdings"). Mariner Holdings then purchased from Hardy Holdings Inc. all of the issued and outstanding stock of the Predecessor Company for a purchase price of approximately $185.5 million (the "Acquisition"). After the Acquisition, the name of the Predecessor Company was changed to Mariner Energy, Inc. In October 1998, JEDI and other shareholders exchanged all of their common shares of Mariner Holdings, the Company's direct parent, for an equivalent ownership percentage in common shares of Mariner Energy LLC. Mariner Energy LLC owns 100% of Mariner Holdings.

Subsequent to the Acquisition, Mariner Energy LLC, Mariner Holdings and Mariner have each entered into various financing and operating transactions with affiliates. In addition the Company may have from time to time engaged in various commercial transactions and have various commercial relationships with Enron and certain affiliates of Enron, such as holding and exploring, exploiting and developing joint working interests in particular prospects and properties and entering into other oil and gas related or financial transactions. Certain of the Company's third-party debt instruments and arrangements restrict the Company's ability to engage in transactions with its affiliates, but those restrictions are subject to significant exceptions. The Company believes that its current agreements with Enron and its affiliates are, and anticipates that any future agreements with Enron and its affiliates will be, on terms no less favorable to the Company than would be obtained in an agreement with a third party. Below is a summary of key transactions between the Company and affiliate entities.

Mariner Energy LLC

ENA Credit Facility - In September 1998 Mariner Holdings established a credit facility to obtain additional capital. The credit facility, as subsequently amended and assigned to Mariner Energy LLC, provided for unsecured, subordinated loans of up to $50 million, bearing interest at LIBOR plus 4.5%, payable at April 30, 2000. The full amount borrowed under this credit facility was repaid on March 21, 2000 with proceeds from the ENA Affiliate Term Loan described below. The net proceeds from this facility were contributed to Mariner.

ENA Affiliate Term Loan - In March 2000, Mariner Energy LLC established an unsecured term loan with ENA to repay amounts outstanding under the ENA Credit Facility with Mariner Energy LLC ($50 million plus accrued interest) described above and Mariner's Senior Credit Facility with ENA ($25 million plus accrued interest), described below, and to provide additional working capital. The additional working capital of $55 million was contributed to Mariner in 2000. The loan bears interest at 15%, which interest accrues and is added to the loan principal. Repayment of the balance of loan principal and accrued interest, which was approximately $143 million as of December 31, 2001, is due March 20, 2003. As part of the loan agreement, two five-year warrants were issued to ENA providing the right to purchase up to 900,000 of common shares of Mariner Energy LLC for $0.01 per share.

We have been informed that the Term Loan was transferred from ENA to an ENA affiliate.

Mariner Holdings, Inc.

1998 Equity Investment - In June 1998, Mariner Holdings issued additional equity to its existing shareholders, including JEDI, for approximately $14.58 per share, for a net investment of $28.8 million, all of which was contributed to Mariner. Mariner Holdings paid approximately $1.2 million as a structuring fee, on a pro rata basis, to existing shareholders participating in this transaction. Approximately $1 million of this fee was paid to ECT Securities Limited Partnership.

Mariner Energy, Inc.

Senior Credit Facility with ENA - In April 1999 Mariner established a senior credit facility with ENA primarily to obtain additional working capital. The facility provided for senior unsecured revolving loans of up to $25 million, bearing interest at LIBOR plus 2.5%, payable quarterly. The full amount borrowed under the senior credit facility was repaid on March 21, 2000, with proceeds from the ENA Affiliate Term Loan described above.

Other Transactions

Oil and Gas Production Sales to ENA or Affiliates - During the three years ending December 31, 2001, 2000 and 1999, sales of oil and gas production to ENA or affiliates were $50.2 million, $73.4 million and $16.2 million, respectively. These sales were generally made on 1 to 3 month contracts. At the time ENA filed its petition for bankruptcy protection, the Company immediately ceased selling its physical production to ENA. As of December 31, 2001, we had an outstanding receivable for $3.0 million from ENA. This amount was not paid as scheduled and is still outstanding. The Company has estimated 90% of this balance is uncollectible and has recorded an allowance and related expense for $2.7 million.

Accounting for Price Risk Management Activities - Mariner engages in price risk management activities from time to time. These activities are intended to manage Mariner's exposure to fluctuations in commodity prices for natural gas and crude oil. The Company primarily utilizes price swaps and costless collars as a means to manage such risk. During 2001 and as of December 31, 2001, all of our hedging contracts were with ENA. As a result of ENA's bankruptcy, the contracts are currently in default. The November and December settlements for oil and gas have not been collected, and there is significant uncertainty that the $4.0 million owed to the Company for the November and December settlements or any future settlements will be collected. As a result of the default, the Company has recorded an allowance representing 90% of the recorded hedge settlements receivable of $4.0 million, fair market value of the derivative assets of $25.8 (as of December 2, 2001), and accounts receivable for oil and gas sales of $3.0 million. Reflected in the earnings of the Company for the period ended December 31, 2001 is a loss for impairment of Enron related receivables of $29.5 million. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137 and No. 138, we have de designated our contracts effective December 2, 2001 and are recognizing all market value changes subsequent to such de-designation in earnings of the Company. The value recorded up to the time of de-designation and included in Accumulated Other Comprehensive Income ("AOCI"), will reverse out of AOCI and into earnings as the original corresponding production, as hedged by the contracts, is produced. As of December 31, 2001, $25.8 million remained in AOCI to be reversed out during the contract periods covering January 1, 2002 through December 31, 2003. Due to the uncertainty of future settlements, the overall effect of the ENA bankruptcy has been to eliminate our commodity price hedge protection.

The following table sets forth the results of hedging transactions during the periods indicated. For the year ended December 31, 2001, the amounts are reflective of the results up to the point of de-designation (December 2, 2001), which include all settled contract months through December of 2001:

The following table sets forth the results of hedging transactions during the periods indicated:

	YEAR ENDING DECEMBER 31,		
	2001	2000	1999
Natural gas quantity hedged (Mmbtu)	17,733	19,569	18,818
Increase (decrease) in natural gas sales (thousands)	$(5,523)	($21,364)	($6,741)
Crude oil quantity hedged (MBbls)	752	1,059	389
Increase (decrease) in crude oil sales (thousands)	$2,393	($14,053)	($2,152)

The following table sets forth our open positions as of December 31, 2001.

TIME PERIOD	NOTIONAL QUANTITIES	FIXED PRICE	FAIR VALUE (in millions)
NATURAL GAS (MMBTU)			

TIME PERIOD	NOTIONAL QUANTITIES	FIXED PRICE	FAIR VALUE (in millions)
January 1 - October 31, 2002			
Fixed price swap purchased	1,831	$2.18	$(0.9)
January 1 - December 31, 2002			
Fixed price swap purchased	12,134	4.43	20.4
April 1 - December 31, 2002			
Fixed price swap purchased	4,125	3.03	0.9
January 1 - December 31, 2003			
Fixed price swap purchased	3,650	3.74	2.0
CRUDE OIL (MBBL)			
January 1 - June 30, 2002			
Fixed price swap purchased	181	25.15	0.9
January 1 - December 31, 2002			
Fixed price swap purchased	365	25.48	1.9
Sub-Total			$25.2(1)
Allowance for impairment			$(22.7)
Total			$2.5

1. Subsequent to the date of default by Enron and ENA, and as of December 31, 2001, the contracts decreased in gross market value by $523,000, which is reflected in the impairment of related party receivables at the net valuation of 10% or $52,000, after consideration for allowance.

Transportation Contract - In 1999 the Company constructed a 29 mile flowline from a third party platform to the Mississippi Canyon 718 subsea well. After commissioning, MEGS LLC, an Enron affiliate that is not in bankruptcy, purchased the flowline from the Company and its joint interest partners. The Company received $8.8 million in cash proceeds that were offset against the cost of constructing the flowline. No gain or loss was recognized. In addition, the Company entered into a firm transportation contract with MEGS LLC at a rate of $0.26 per Mmbtu to transport the Company's share of 86 Bcf of natural gas from the commencement of production through March 2009. The Company's working interest in the well at December 31, 2001 was 51%. For the year ending December 31, 2001, the Company paid $4.2 million on this contract. The remaining volume commitment is 30.8 Bbtu or $7.9 million net to the Company. Pursuant to the contract, the Company must deliver minimum quantities through the flowline or be subject to minimum monthly payment requirements. Throughout 2001 the Company failed to meet these minimum requirements and paid $1.5 million relating to the shortfall. The Company estimates that future production will also fail to meet minimum delivery requirements and has accrued $972,000 for future shortfalls.

Services Agreement - In conjunction with the change of certain key management positions, the Company entered into a services agreement for ENA to provide certain administrative services. The Company is obligated to pay $45,000 per month under this agreement.

Supplemental Affiliate Data - Provided below is supplemental balance sheet and income statement amounts for affiliate entities:

	YEAR ENDED DECEMBER 31,			
	2001 AMOUNTS (in millions)		2000 AMOUNTS (in millions)	
BALANCE SHEET DATA				
RELATED PARTY RECEIVABLE:				
Derivative Asset	$2.5			
Settled Hedge Receivable	0.4			
Oil and Gas Receivable	0.3	$3.2	$6.9	$6.9
ACCURED LIABILITIES:				
Transportation Contract	$0.9		--	
Service Agreement	$0.3	$1.2	--	--
STOCKHOLDERS' EQUITY:				
Common Stock	$0.001		$0.001	
Additional Paid-in Capital	$227.3	$227.3	$227.3	$227.3
INCOME STATEMENT DATA				
Oil and Gas Sales	$50.2		$73.4	
General and Administrative Expenses	0.2		--	
Transportation Expenses	4.2		3.7	
Impairment of Enron Related Receivables	29.5		--	

3. LIQUIDITY

As of December 31, 2001, we had a working capital deficit of approximately $19.6 million, compared to a working capital deficit of $15.4 million at December 31, 2000. The increase in the working capital deficit was primarily a result of a higher accounts payable, as a result of work being performed on our King Kong / Yosemite and Crater Lake projects in progress at year end. We expect our 2002 capital expenditures, excluding capitalized general and administrative, interest costs and proceeds from property conveyances (see "Note 4. Recent Events"), to be approximately $101.9 million, which would exceed cash flow from operations. However, we believe there will be adequate cash flow due to increased commodity prices and proceeds from property conveyances in order for us to fund our remaining planned activities in 2002. There can be no assurance that our access to capital will be sufficient to meet our needs for capital. As such, we may be required to reduce our planned capital expenditures and forego planned exploratory drilling.

The Company's Revolving Credit Facility matures in October 2002. We expect to begin renegotiation of our agreement with existing banks that provide the facility during the first half of 2002. We plan to minimize the use of the facility until such time as this agreement can be renegotiated or replaced with a similar agreement. There is no assurance that this agreement can be renegotiated or replaced. In addition our parent, Mariner Energy LLC, is currently obligated under a three-year unsecured term loan with an ENA affiliate, which matures in March 2003. Currently we expect to attempt to obtain an extension on this agreement. In the event Mariner Energy, LLC is unable to obtain an extension or restructure its obligation, Mariner Energy LLC would either default or be forced to sell its interest in Mariner Energy, Inc., or cause Mariner to sell a substantial portion of its assets to repay its Revolving Credit Facility and outstanding Senior Subordinated Notes to that it could distribute cash to Mariner Energy LLC to be used to repay the term loan. In the event either a change of control occurs of the company or a sale of a substantial portion of the Company's assets, both the balances outstanding under the Senior Subordinated Notes and Revolving Credit Facility would have to be repaid prior to payment of the term loan. Although we believe we will be successful in extending the term loan, there can be no assurance that an extension will be obtained.

4. RECENT EVENTS

On March 20, 2002, with bids totaling $10.9 million net to us, we were the apparent high bidder solely or with industry partners, on 12 out of 16 blocks on which we and our partners submitted bids in the Central Gulf of Mexico Oil and Gas Lease Sale 182 held on that date. Each of the blocks is in water depths ranging from approximately 20 feet to 2,400 feet. Mariner has a 100% working interest in four of the blocks, 50% working interest in seven blocks and 20% working interest in one block.

In April 2002, we sold 50% of our working interest in our Falcon discovery and surrounding blocks, located in East Breaks Block 579 in the western Gulf of Mexico, for $48.8 million. Subsequent to the sale we have a 25% working interest in the discovery and surrounding blocks. The project is currently expected to begin production in the first quarter of 2003. At December 31, 2001, the Falcon project had 66.8 Bcfe assigned as proven reserves.

The net carrying value of our proved oil and gas properties is limited to an estimate of the future net revenues (discounted at 10%) from proved oil and gas reserves based on period-end prices and costs plus the lower of cost or estimated fair value of unproved properties. As a result of this limitation, based on year-end prices of $2.65 per Mcf of natural gas and $19.43 per Bbl of crude oil, an impairment of oil and gas properties of approximately $37.8 million would be required as of December 31, 2001. However, as allowed by the Securities and Exchange Commission guidelines, since both natural gas and crude oil prices have significantly increased since year-end, no writedown was required as of December 31, 2001.

5. LONG-TERM DEBT

Revolving Credit Facility - In 1996, the Company entered into an unsecured revolving credit facility (the "Revolving Credit Facility") with Bank of America as agent for a group of lenders (the "Lenders").

The Revolving Credit Facility provides for a maximum $150 million revolving credit loan. Subsequent to the semi annual redetermination, the available borrowing base under the Revolving Credit Facility is expected to be $45 million and is subject to periodic redetermination. The Revolving Credit Facility had an outstanding balance of $0 at December 31, 2001. On June 28, 1999, the Revolving Credit Facility was amended to extend the maturity date from October 1, 1999 to October 1, 2002 and to pledge certain Mariner interests to collateralize the Revolving Credit Facility.

Borrowings under the Revolving Credit Facility bear interest, at the option of the Company, at either (i) LIBOR plus 0.75% to 1.25% (depending upon the level of utilization of the Borrowing Base) or (ii) the higher of (a) the agent's prime rate or (b) the federal funds rate plus 0.5%. The effective interest rate at December 31, 2001 was 8.49%. The Company incurs a quarterly commitment fee ranging from 0.25% to 0.375% per annum on the average unused portion of the Borrowing Base, depending upon the level of utilization.

The Revolving Credit Facility, as amended, contains various restrictive covenants which, among other things, restrict the payment of dividends, limit the amount of debt the Company may incur, limit the Company's ability to make certain loans and investments, limit the Company's ability to enter into certain hedge transactions and provide that the Company must maintain specified relationships between cash flow and fixed charges and cash flow and interest on indebtedness. As of December 31, 2001, the Company was in compliance with all such requirements.

10 1/2% Senior Subordinated Notes - On August 14, 1996, the Company completed the sale of $100 million principal amount of 10 1/2% Senior Subordinated Notes Due 2006, (the "Notes"). The proceeds of the Notes were used by the Company to (i) pay a dividend to Mariner Holdings, which used the dividend to fully repay a bridge loan from JEDI incurred in the Acquisition, and (ii) repay a previous revolving credit facility. The Notes bear interest at 101/2% payable semiannually in arrears on February 1 and August 1 of each year. The Notes are unsecured obligations of the Company, and are subordinated in right of payment to all senior debt (as defined in the indenture governing the Notes) of the Company, including indebtedness under the Revolving Credit Facility.

The indenture pursuant to which the Notes are issued contains certain covenants that, among other things, limit the ability of the Company to incur additional indebtedness, pay dividends, redeem capital stock, make investments, enter into transactions with affiliates, sell assets and engage in mergers and consolidations. As of December 31, 2001, the Company was in compliance with all such requirements.

The Notes are redeemable at the option of the Company, in whole or in part, at any time on or after August 1, 2001, initially at 105.25% of their principal amount, plus accrued interest, declining ratably to 100% of their principal amount, plus accrued interest, on or after August 1, 2003.

In the event of a change of control of the Company (as defined in the indenture pursuant to which the Notes are issued), each holder of the Notes (the "Holder") will have the right to require the Company to repurchase all or any portion of such Holder's Notes at a purchase price equal to 101% of the principal amount thereof, plus accrued interest.

Cash paid for interest for the years ending December 31, 2001, 2000 and 1999 was $11.4 million, $15.3 million and $15.1 million, respectively.

6. STOCKHOLDER S EQUITY

Stock Option Plan - During June 1996, Mariner Holdings established the Mariner Holdings, Inc. 1996 Stock Option Plan (the "Plan") providing for the granting of stock options to key employees and consultants. Options granted under the Plan must not be less than the fair market value of the shares at the date of grant. The maximum number of shares of Mariner Holdings common shares that may be issued under the Plan was 142,800. In June 1998, the Plan was amended to increase the number of eligible shares to be issued to 202,800. In September 1998, concurrent with the exchange of each common share of Mariner Holdings for twelve common shares of Mariner Energy LLC, the Plan was amended to make Mariner Energy LLC the Plan sponsor. The maximum number of shares of common shares that can be issued under the Plan was correspondingly increased to 2,433,600.

During the years ended December 31, 2001, 2000 and 1999, Mariner Energy LLC granted stock options ("Options") of 13,166, 39,144 and 215,748, respectively. No options have been exercised, but 141,264 options have been canceled during the three year period. At December 31, 2001, options to purchase 2,200,620 shares had been issued at an exercise price ranging from $8.33 to $14.58 per share. These Options generally become exercisable as to one-fifth to one-third on each of the first three to five anniversaries of the date of grant. The Options expire from seven years to ten years after the date of grant.

The Company applies APB Opinion 25 and related interpretations in accounting for the Plan. Accordingly, no compensation cost has been recognized for the Plan. Had compensation cost for the Plan been determined based on the fair value at the grant date for awards under the Plan consistent with the method of SFAS No. 123, the Company's net income for the year ended December 31, 2001 would have been decreased by $325,000 to $12,068,000 and the net income for the year ending 2000 would have decreased $422,000 and the net loss for 1999 $428,000, respectively. The effects of applying SFAS No. 123 in this pro forma disclosure are not indicative of future amounts. The fair value of each option grant is estimated on the date of grant using a present value calculation, risk free interest of 4.54% for the year ending December 31, 2001 and 4.75% and 6.46% for the years ending December 31, 2000 and 1999, respectively. Stock options available for future grant amounted to 294,250 shares at December 31, 2001. Exercisable stock options amounted to 2,044,742 shares at December 31, 2001.

7. EMPLOYEE BENEFIT AND ROYALTY PLANS

Employee Capital Accumulation Plan - The Company provides all full-time employees participation in the Employee Capital Accumulation Plan (the "Plan") which is comprised of a contributory 401(k) savings plan and a discretionary profit sharing plan. Under the 401(k) feature, the Company, at its sole discretion, may contribute an employer-matching contribution equal to a percentage not to exceed 50% of each eligible participant's matched salary reduction contribution as defined by the Plan. Under the discretionary profit sharing contribution feature of the Plan, the Company's contribution, if any, must be determined annually and must be 4% of the lesser of the Company's operating income or total employee compensation and shall be allocated to each eligible participant pro rata to his or her compensation. During 2001, 2000 and 1999, the Company contributed $369,677, $291,940 and $180,000, respectively, to the Plan. This plan is a continuation of a plan provided by the Predecessor Company.

Overriding Royalty Interests - Pursuant to agreements, certain key employees and consultants are entitled to receive, as incentive compensation, overriding royalty interests ("Overriding Royalty Interests") in certain oil and gas prospects acquired by the Company. Such Overriding Royalty Interests entitle the holder to receive a specified percentage of the gross proceeds from the future sale of oil and gas (less production taxes), if any, applicable to the prospects. Cash payments made by the Company under these agreements for the three years ended December 31, 2001, 2000 and 1999 were $5.8, $2.9 million and $1.0 million, respectively.

8. COMMITMENTS AND CONTINGENCIES

Enron Matters - See "Note 2. Related-Party Transactions", the Company has various related-party transactions and certain control relationships with Enron Corp. and affiliates.

Minimum Future Lease Payments - The Company leases certain office facilities and other equipment under long-term operating lease arrangements. Minimum rental obligations under the Company's operating leases in effect at December 31, 2001 are as follows (in thousands):

2002	1,542
2003	728
2004	121
2005	41
2006	10
Total	$2,442

Rental expense, before capitalization, was approximately $1,492,000, $1,228,000 and $1,170,000 for the years ended December 31, 2001, 2000 and 1999, respectively.

Other Commitments - In the ordinary course of business we enter into long-term commitments to purchase seismic data. The minimum annual payments under these contracts are $6.8 million in 2002, $6.3 million in 2003 and $2.7 million in 2004.

Deepwater Rig - In the fourth quarter of 1999, Noble Drilling Corporation filed suit against the Company alleging breach of contract regarding a letter of intent for a five year Deepwater rig contract. In February 2000, both the Company and Noble Drilling Corporation entered into a settlement agreement whereby the Company committed to using this Deepwater rig for a minimum of 660 days over a five-year period at market-based day rates for comparable drilling rigs in comparable water depths subject to a floor day rate ranging from $65,000 to $125,000. In exchange for market-based day rates, Noble Drilling was assigned working interests in seven of the Company's deepwater exploration prospects. The Company will pay Noble Drilling's share of the costs of drilling the initial test well on each of these prospects. As of December 31, 2001, 208 days remained on this commitment and the Company has drilled six of the seven prospects.

Litigation - The Company, in the ordinary course of business, is a claimant and/or a defendant in various legal proceedings, including proceedings as to which the Company has insurance coverage. The Company does not consider its exposure in these proceedings, individually and in the aggregate, to be material.

9. INCOME TAXES

The following table sets forth a reconciliation of the statutory federal income tax with the income tax provision (in thousands):

	YEAR ENDING DECEMBER 31,					
	2001		**2000**		**1999**	
	$	**%**	**$**	**%**	**$**	**%**
Income (loss) before income taxes	12,393	--	21,861	--	(9,970)	--
Income tax expense (benefit) computed at statutory rates	4,338	35	7,651	35	(3,490)	(35)
Change in valuation allowance	(4,544)	(37)	(8,742)	(40)	2,718	27
Other	206	2	1,091	5	772	8
Tax Expense	--	--	--	--	--	--

No federal income taxes were paid by the Company during the years ended December 31, 2001, 2000 or 1999.

The Company's deferred tax position reflects the net tax effects of the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Significant components of the deferred tax assets and liabilities are as follows (in thousands):

YEAR ENDING DECEMBER 31,		
2001	**2000**	**1999**

	YEAR ENDING DECEMBER 31,		
DEFERRED TAX ASSETS:			
Net operating loss carry forwards	$21,618	$43,142	$45,075
Differences between book and tax basis of receivables	10,335	--	--
Valuation allowance	(18,597)	(23,141)	(31,884)
Total net deferred tax assets	13,356	20,001	13,191
DEFERRED TAX LIABILITIES:			
Differences between book and tax bases of properties	(13,356)	(20,001)	(13,191)
Total net deferred taxes	--	--	--

As of December 31, 2001, the Company had a cumulative net operating loss carryforward ("NOL") for federal income tax purposes of approximately $61.8 million, which begins to expire in the year 2012. A valuation allowance is recorded against tax assets which are not likely to be realized. Because of the uncertain nature of their ultimate realization, as well as past performance and the NOL expiration date, the Company has established a valuation allowance against this NOL carryforward benefit and for all net deferred tax assets in excess of net deferred tax liabilities.

10. OIL AND GAS PRODUCING ACTIVITIES and CAPITALIZED COSTS

The results of operations from the Company's oil and gas producing activities were as follows (in thousands):

	YEAR ENDING DECEMBER 31,		
	2001	**2000**	**1999**
Oil and gas sales	$155,000	$121,150	$54,485
Production costs	(20,063)	(17,192)	(11,453)
Transportation	(12,011)	(7,789)	(2,017)
Depreciation, depletion and amortization	(63,503)	(56,846)	(32,121)
Results of operations	$59,423	$ 39,323	$ 8,894

Costs incurred in property acquisition, exploration and development activities were as follows (in thousands, except per equivalent mcf amounts):

	YEAR ENDING DECEMBER 31,		
	2001	**2000**	**1999**
Property acquisition costs Unproved properties	$ 8,721	$ 14,000	$ 14,843
Exploration costs	57,665	17,192	13,836
Development costs	96,999	76,276	52,144
Proceeds from property conveyances	(90,500)	(29,002)	(19,758)
Total costs, net of proceeds from property conveyances	$72,885	$78,466	$61,065

	YEAR ENDING DECEMBER 31,		
Depreciation, depletion and amortization rate per equivalent Mcf before impairment	$1.73	$1.57	$1.29

The Company capitalizes internal costs associated with exploration activities in progress. These capitalized costs were approximately $10,508,000, $11,625,000 and $9,440,000 for the years ended December 31, 2001, 2000 and 1999, respectively.

The following table summarizes costs related to unevaluated properties which have been excluded from amounts subject to amortization at December 31, 2001. The Company regularly evaluates these costs to determine whether impairment has occurred. The majority of these costs are expected to be evaluated and included in the amortization base within three years.

	COST INCURRED DURING THE YEAR ENDED DECEMBER 31,				Total at
	2001	2000	1999	PRIOR	December 31, 2001
Property acquisition costs	$3,340	$1,714	$130	$8,332	$13,516
Exploration costs	13,786	813	1,226	--	15,825
Total	$17,126	$2,527	$1,356	$8,332	$29,341

All of the excluded costs at December 31, 2001 relate to activities in the Gulf of Mexico.

11. SUPPLEMENTAL OIL AND GAS RESERVE AND STANDARDIZED MEASURE INFORMATION (UNAUDITED)

Estimated proved net recoverable reserves as shown below include only those quantities that are expected to be commercially recoverable at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods. Proved developed reserves represent only those reserves expected to be recovered through existing wells. Proved undeveloped reserves include those reserves expected to be recovered from new wells on undrilled acreage or from existing wells on which a relatively major expenditure is required for recompletion. Also included in the Company's proved undeveloped reserves as of December 31, 2001 were reserves expected to be recovered from wells for which certain drilling and completion operations had occurred as of that date, (See "Note 4. Recent Events" regarding sale of 50% of working interest in the Falcon project subsequent to December 31, 2001) but for which significant future capital expenditures were required to bring the wells into commercial production.

Reserve estimates are inherently imprecise and may change as additional information becomes available. Furthermore, estimates of oil and gas reserves, of necessity, are projections based on engineering data, and there are uncertainties inherent in the interpretation of such data as well as in the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Accordingly, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers at different times may vary substantially. There also can be no assurance that the reserves set forth herein will ultimately be produced or that the proved undeveloped reserves set forth herein will be developed within the periods anticipated. It is likely that variances from the estimates will be material. In addition, the estimates of future net revenues from proved reserves of the Company and the present value thereof are based upon certain assumptions about future production levels, prices and costs that may not be correct when judged against actual subsequent experience. The Company emphasizes with respect to the estimates prepared by independent petroleum engineers that the discounted future net cash flows should not be construed as representative of the fair market value of the proved reserves owned by the Company since discounted future net cash flows are based upon projected cash flows which do not provide for changes in oil and natural gas prices from those in effect on the date indicated or for escalation of expenses and capital costs subsequent to such date. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Actual results will differ, and are likely to differ materially, from the results estimated.

ESTIMATED QUANTITIES OF PROVED RESERVES
(in thousands)

ESTIMATED QUANTITIES OF PROVED RESERVES
(in thousands)

	OIL (Bbl)	NATURAL GAS (Mcf)	NATURAL GAS EQUIVALENT (Mcfe)
DECEMBER 31, 1998	**9,359**	**128,895**	**185,049**
Revisions of previous estimates	715	(5,098)	(808)
Extensions, discoveries and other additions	1,225	24,972	32,322
Sale of reserves in place	(742)	(8,856)	(13,308)
Production	(630)	(21,123)	(24,903)
DECEMBER 31, 1999	**9,927**	**118,790**	**178,352**
Revisions of previous estimates	324	(13,255)	(11,311)
Extensions, discoveries and other additions	4,123	24,649	49,387
Sale of reserves in place	(215)	(673)	(1,963)
Purchase of reserves in place	--	25,455	25,455
Production	(1,762)	(25,710)	(36,282)
DECEMBER 31, 2000	**12,387**	**129,256**	**203,578**
Revisions of previous estimates	2,079	(8,240)	4,236
Extensions, discoveries and other additions	2,736	96,711	113,127
Sale of reserves in place	(4,123)	(22,470)	(47,208)
Production	(2,978)	(18,796)	36,664
DECEMBER 31, 2001	**10,101**	**176,461**	**237,067**

ESTIMATED QUANTITIES OF PROVED DEVELOPED RESERVES
(in thousands)

	OIL (Bbl)	NATURAL GAS (Mcf)	NATURAL GAS EQUIVALENT (Mcfe)
December 31, 1999	3,799	82,760	105,554
December 31, 2000	5,540	61,623	94,863
December 31, 2001	4,675	44,040	72,090

The following is a summary of a standardized measure of discounted net cash flows related to the Company's proved oil and gas reserves. The information presented is based on a valuation of proved reserves using discounted cash flows based on year-end prices, costs and economic conditions and a 10% discount rate. The additions to proved reserves from new discoveries and extensions could vary significantly from year to year. Additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant. Accordingly, the information presented below should not be viewed as an estimate of the fair value of the Company's oil and gas properties, nor should it be considered indicative of any trends.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS
(in thousands)

	YEAR ENDING DECEMBER 31,		
	2001	2000	1999
Future cash inflows	$615,131	$1,758,734	$490,239
Future production costs	(149,636)	(161,617)	(122,681)
Future development costs	(145,243)	(162,277)	(70,774)
Future income taxes	--	(372,059)	--
Future net cash flows	294,879	1,062,781	296,784
Discount of future net cash flows at 10% per annum	(62,851)	(290,075)	(85,558)
Standardized measure of discounted future net flows	$232,028	$772,705	$211,226

During recent years, there have been significant fluctuations in the prices paid for crude oil in the world markets and in the United States, including the posted prices paid by purchasers of the Company's crude oil. The weighted average prices of oil and gas at December 31, 2001, 2000 and 1999, used in the above table, were $16.40, $26.36 and $23.85 per Bbl, respectively, and $2.60, $11.32 and $2.23 per Mcf, respectively, and do not include the effect of hedging contracts in place at period end.

The following are the principal sources of change in the standardized measure of discounted future net cash flows (in thousands):

	YEAR ENDING DECEMBER 31,		
	2001	2000	1999
Sales and transfers of oil and gas produced, net of production costs	$(122,053)	$(96,169)	$(41,015)
Net changes in prices and production costs	(661,871)	503,871	77,532
Extensions and discoveries, net of future development and production costs	130,512	214,022	33,357
Development costs during period and net change in development costs	40,674	39,736	(3,661)
Revision of previous quantity estimates	(106,813)	(13,365)	(984)
Purchases of reserves in place	--	157,657	--
Sales of reserves in place	(172,072)	(2,584)	(15,535)
Net change in income taxes	270,509	(270,510)	--
Accretion of discount before income taxes	104,321	29,678	19,900
Changes in production rates (timing) and other	(23,884)	(857)	(5,997)
Net change	$(540,677)	$561,479	$63,597

Item 9. Changes In and Disagreements With Accountants On Accounting and Financial Disclosure

None

PART III

Item 10. Directors and Executive Officers of the Registrant

Set forth below are the names, ages and positions of our executive officers and directors and a key consultant as of March 4, 2002. All directors are elected for a term of one year and serve until their successors are elected and qualified. All executive officers hold office until their successors are elected and qualified.

Name	Age	Position with the Company
Scott Josey	44	Chairman of the Board and Officer
Allan Keel	42	President and Chief Executive Officer
Richard R. Clark	46	Executive Vice President
Michael A. Wichterich	34	Vice President of Finance & Administration
C. Ken Burgess	55	Vice President of Drilling & Production
Mike van den Bold	39	Vice President of Development
Gregory K. Harless	52	Vice President of Oil & Gas Marketing
Thomas E. Young	43	Vice President of Business Development & Land
Kelly D. Zelikovitz	43	General Counsel and Secretary
David S. Huber	51	Consultant and Director of Deepwater Development
Robert E. Henderson	49	Director
Michael W. Strickler	46	Director
Craig A. Fox	46	Director
Jesus G. Melendrez	42	Director
Raymond M. Bowen, Jr.	42	Director
Jeffrey McMahon	41	Director
Robert H. Walls, Jr.	41	Director

Mr. Josey is the Chairman of the Board of Mariner Energy, Inc. From 2000 to 2001, Mr. Josey served as Vice President and Co-Manager of Enron Energy Capital Resources, which provided debt, mezzaine, and equity capital to energy companies. From 1995 to 2000, Mr. Josey was the managing partner of Sagestone Capital, which provided investment-banking services to the oil and gas industry and portfolio management services to Commonfund Capital, a fund of funds for endowments and foundations. From 1993 to 1995, Mr. Josey was a Director with Enron Capital & Trade Resources Corp. in its energy investment group. From 1982 to 1993, Mr. Josey was with Texas Oil and Gas Corp., where he worked in all phases of its drilling, production, pipeline, corporate planning and commercial activities. Mr. Josey is a member of the Society of Petroleum Engineers and the Independent Producers Association of America. Mr. Josey received his BS in mechanical engineering from Texas A&M University, his MBA from the University of Texas, and his MS in petroleum engineering from the University of Houston.

Mr. Keel is President and Chief Executive Officer of Mariner Energy, Inc. He joined the company in August of 2001. Prior to joining Mariner, Mr. Keel was employed as Vice President of Enron Energy Capital Resources where he originated and structured volumetric production payments and private equity placements. From 1996 until mid-2000, Mr. Keel was employed by Westport Resources Corporation as its Vice President and General Manager of the Gulf Coast region. In this capacity, Mr. Keel built Westport's Gulf of Mexico business from a grassroots effort into a viable Gulf of Mexico entity. From 1984 to 1996, Mr. Keel was employed by Energen Resources where he directed the company's exploration, joint venture, and acquisition activities. He received his BS and MS degrees in geology from the University of Alabama and a MBA from Owen School of Management at Vanderbilt University. Mr. Keel is a member of the American Association of Petroleum Geologists and the Independent Producers Association of America.

Mr. Clark has served us in various engineering and operations activities since 1984 and has been Executive Vice President since May 1998. He served as Senior Vice President of Production from 1991 until May 1998 and has served as a director since 1988. Prior to joining us he worked as a Production Engineer in the Offshore Production Group of Shell Oil Company.

Mr. Wichterich has been our Vice President of Finance and Administration since September 2001. Prior to obtaining this position he was the Company's Corporate Controller from 1998 through August 2001. He was previously employed at

PricewaterhouseCoopers from 1989 through 1998 with ending title of Senior Manager.

Mr. Burgess has serviced as Vice President of Drilling and Production since September 2001. Before obtaining this position he was Manager of Drilling from 1998 until August 2001. Prior to this time he was employed by Conoco Inc., serving in various drilling engineering and operations management positions, both domestically and international. Ken has 29 years industry experience, including 15 years in GOM and international arenas.

Mr. van den Bold has been our Vice President of Development since October 2001. Prior to obtaining his position, he was a Senior Development Geologist. He was previously employed at British Borneo and British Petroleum from 1986 through 2000 in various exploration and development positions. He received his BS and MS degrees in geology from the Louisiana State University.

Mr. Harless has been our Vice President - Oil and Gas Marketing since 1990. His experience before joining us in 1988 included Vice President of marketing and regulatory affairs of Enron Oil and Gas Company and District Operations Manager with Coastal States Oil & Gas Co.

Mr. Young joined Mariner Energy, Inc., in 1985 and is currently serving as Vice President - Business Development and Land. Tom has spent the majority of his career with Mariner Energy serving in various managerial positions, which include domestic and international negotiations. During his tenure, Tom has been involved in acquisition, exploration, production and marketing of properties in the Gulf of Mexico, with emphasis in Deepwater Gulf of Mexico. His last assignment as Vice President - Land, included, among other things, supervision of lease acquisitions, contract negotiations, planning, forecasting, and strategy formation for the Company.

Ms. Zelikovitz has been our General Counsel and Secretary since August 2000. She is in private practice and has a contractual relationship with us. Prior to May 1998, she held various legal and management positions with Mobil Oil Corporation, Greenhill Petroleum Corporation, Union Texas Petroleum Corporation, and with a Houston-based law firm.

Mr. Huber, a consultant, began his association with us in 1991 as a deepwater project management consultant and is presently our Director of Deepwater Developments. Prior to joining us, Mr. Huber was employed by Hamilton Oil Corporation in the North Sea from 1981 to 1991, holding positions of production manager, planning and economics manager, and engineering manager. He was the deepwater drilling engineering supervisor for Esso Exploration, Inc. from 1974 to 1980.

Mr. Henderson has been a Director since 1985. From May 1996 to August 2001 he was President and Chief Executive Officer. Mr. Henderson served as a director of London-based Hardy Plc, our former parent company, between 1989 and 1996. From 1984 to 1987, he served us or predecessors as Vice President of Finance and Chief Financial Officer. From 1976 to 1984, he held various positions with ENSTAR Corporation, including Treasurer of ENSTAR Petroleum, which operated in the U.S. and Indonesia.

Mr. Strickler has been a Director since 1989. From May 1996 until August 2001 he served as Senior Vice President of Exploration. Prior to joining us, Mr. Strickler worked for several independent oil companies as an exploration geologist, generating and evaluating exploration plays in the Gulf Coast, Mid Continent, Rocky Mountains, West Texas and several overseas basins.

Mr. Fox is Vice President and Technical Manager for Enron Energy Capital Resources. Mr. Fox received his bachelor's of science degree in mechanical engineering from Texas A&M University in 1977. He was employed with Houston Oil & Minerals, Tenneco Oil Company, and Sandefer Oil & Gas as a reservoir and production engineer for 15 years before joining Enron Finance Corp. in 1992 as a Senior Reservoir Engineer. He became a Vice President in the engineering group supporting producer finance in 1995.

Mr. Melendrez is a Vice President of ENA and is responsible for the execution and structuring of upstream transactions. Prior to joining ENA in 1999, Mr. Melendrez was Sr. Vice President of Enserch Energy Services, Inc. He has held financial positions with several Enron affiliates since the early 1990's that involved loan restructuring and power marketing.

Mr. Bowen has served as a director since January 2000. He is currently Managing Director of ENA and Co-Head of the Commercial Transactions Group and has held various management positions with ENA since 1996. Prior to joining ENA, Mr. Bowen was a Vice President and Senior Banker in Citicorp's Petroleum, Metals and Mining Department in Houston.

Mr. McMahon became a director in March 2002. Since January 28, 2002, Mr. McMahon holds the position of President & Chief Operating Officer of Enron Corp. Mr. McMahon is responsible for managing the reorganization process under Chapter 11 of the bankruptcy code as well as the day to day operations of the company. Mr. McMahon was appointed to this position as part of a complete change in the executive management of Enron in late 2001 and early 2002. For a short period prior to this, Mr. McMahon held the position of Chief Financial Officer. Previously, Mr. McMahon held the position of President and Chief Executive Officer of Enron Industrial Markets. In this operating position, Mr. McMahon was responsible for all aspects of Enron's forest products and steel business worldwide.

Mr. Walls is currently Executive Vice President and General Counsel for Enron Corp. He held the position of Managing Director and Deputy General Counsel of Enron Corp. from August, 2000 to March, 2002. Prior to that he served as Managing Director and General Counsel of Enron International Inc. where he was responsible for the legal activities of Enron's international business. Rob began his legal career with Vinson & Elkins, L.L.P. in 1985, where he gained extensive experience in the areas of energy, finance and international law. He left Vinson & Elkins in 1992 to serve as Vice President and General Counsel of Enron Power Corp. and became Senior Vice President and General Counsel of Enron Development Corp. when Enron reorganized in late 1995.

The Shareholders' Agreement requires that the Board of Directors include at least three nominees of the Management Stockholders. The remaining board members are to include nominees of JEDI. See "Certain Relationships and Related Transactions on page 72.

Item 11. Executive Compensation

Summary Compensation Table

The following table sets forth the annual compensation for Mariner's Chief Executive Officer and the four other most highly compensated executive officers for the three fiscal years ended December 31, 2001. These individuals are sometimes referred to as the "named executive officers".

NAME AND PRINCIPAL POSITION	YEAR	ANNUAL SALARY	OTHER ANNUAL COMPENSATION (1)	CURRENT YEAR COMPENSATION UNDER OUR OVERRIDING ROYALTY PROGRAM (2)	ALL OTHER COMPENSATION (3)
Allan D. Keel(4)	2001	0	0	0	0
President and Chief Executive	2000	0	0	0	0
Officer	1999	0	0	0	0
Richard R. Clark	2001	250,000	6,800	7,043	270
Executive Vice President	2000	235,000	3,680	5,596	210
	1999	225,000	6,400	3,508	243
C. Ken Burgess	2001	170,000	6,800	0	53,489
Vice President - Drilling and	2000	141,500	3,300	0	51,040
Production	1999	135,000	1,350	0	9,140
Gregory K. Harless	2001	156,000	5,960	4,400	414
Vice President - Oil&Gas Marketing	2000	149,000	3,290	3,506	414
	1999	143,000	5,720	2,192	497
Donald M. Clement, Jr.	2001	154,000	6,800	2,256	45,270
Exploration Manager, Gulf of Mexico	2000	144,000	3,480	1,461	51,645
	1999	137,000	1,718	1,075	14,670
Thomas E. Young	2001	150,000	5,160	2,840	180
Vice President - Business	2000	129,000	2,817	2,356	180
Development and Land	1999	120,000	4,200	1,418	243

1. Amounts shown reflect our contribution under the discretionary profit sharing feature of its Employee Capital Accumulation Plan. See "--401(k) Plan". For each of the named executive officers, the aggregate amount of perquisites and other personal benefits did not exceed the lesser of $50,000 or 10% of the officer's total annual salary and bonus and information with respect thereto is not included.

2. These amounts include the value conveyed during the applicable year attributable to overriding royalty interests assigned to the named executive officer during the applicable year and distributions received, if any, during the applicable year attributable to overriding royalty interests assigned to the named executive officers during the applicable year. For information on overriding royalty payments received during the applicable year attributable to overriding royalty interests assigned to the named executive officer during past years, see the table below under "Overriding Royalty Program." These amounts also do not include amounts received during the applicable year as a result of sales of overriding royalty interests by individuals, normally in connection with sales of properties by us. No such sales were made in 2001, 2000 or

1999.

3. Amounts shown reflect insurance premiums paid by us with respect to term life insurance for the benefit of the named executive officers and any performance bonuses paid during the year.

4. Mr. Keel performs his services under a Services Agreement with ENA at $20,000 per month.

Options

None of the named executive officers exercised stock options in 2001. The following table shows the number and value of options owned by our named executive officers at December 31, 2001. All of the options described in the table below have been issued under the Mariner Energy LLC 1996 Stock Option Plan.

	NUMBER OF COMMON SHARES UNDERLYING UNEXERCISED OPTIONS AT DECEMBER 31, 2001	
	EXERCISABLE	UNEXERCISABLE
C. Ken Burgess	31,973	12,283
Richard R. Clark	167,928	0
Donald M. Clement, Jr.	96,690	8,766
Gregory K. Harless	42,840	0
Thomas E. Young	42,840	0

Under the Mariner Energy LLC 1996 Stock Option Plan, a committee of the board of directors is authorized to grant options to purchase common shares, including options qualifying as "incentive stock options" under Section 422 of the Internal Revenue Code and options that do not so qualify, to employees and consultants as additional compensation for their services to us. The 1996 plan is intended to promote our long-term financial interests by providing a means by which designated employees and consultants may develop a sense of proprietorship and personal involvement in our development and financial success. We believe that this encourages them to remain with and devote their best efforts to our business and to advance the mutual interests of our shareholders and us. A total of 2,433,600 common shares may be issued under options granted under the 1996 plan, subject to adjustment for any share split, share dividend or other change in the common shares or our capital structure. Options to purchase 2,139,350 common shares are outstanding under the 1996 plan, 2,044,742 of which are currently exercisable. The exercise price for outstanding options to purchase an aggregate of 1,608,516 shares under the 1996 plan is $8.33 per share, and the exercise price for options to purchase the remaining outstanding aggregate of 530,834 shares under the 1996 plan is $14.58 per share. Subject to the provisions of the 1996 plan, the compensation committee is authorized to determine who may participate in the 1996 plan, the number of shares that may be issued under each option granted under the 1996 plan, and the terms, conditions and limitations applicable to each grant. Subject to some limitations, the board of directors of Mariner Energy LLC is authorized to amend, alter or terminate the 1996 plan.

Employment Agreements

We and each of the named executive officers are parties to employment agreements that expire on September 30, 2002 except for Mr. Keel who performs his services under a Service Agreement with ENA at $20,000 per month. Following the expiration date of an employment agreement or the expiration of any extended term, the employment agreements extend for three to six months, unless notice of termination is given by either us or the named executive officer at least six months before the end of the initial term or extended term, as applicable.

Under the employment agreements, the current annual salaries are $250,000 for Mr. Clark, $170,000 for Mr. Burgess, $156,000 for Mr. Harless, $154,000 for Clement and $150,000 for Mr. Young. Our board of directors may in its discretion increase their salaries.

The named executive officers are entitled to participate in any medical, dental, life and accidental death and dismemberment insurance programs and retirement, pension, deferred compensation and other benefit programs instituted by us from time to time. The employees are also entitled to vacation, reimbursement of specified expenses and, depending on the employment agreement, an automobile allowance and reimbursement for expenses related to the use of that vehicle. As incentive compensation, Mr. Clark, Mr. Harless, and Mr. Young are entitled to receive overriding royalty interests in some oil and gas prospects that we have acquired under our overriding royalty program. Mr. Burgess and Mr. Clement are entitled to receive annual cash bonuses and incentive stock option awards under an incentive compensation plan separate from other named executive officers.

If we terminate a named executive officer's employment agreement without cause, if the named executive officer terminates his employment contract for good reason, or if we give notice of termination on the expiration of his term of employment, then the named executive officer will be entitled to, among other things:

- the value of his salary and other benefits through the end of the initial term or any extended term of the employment agreement;
- a lump sum cash payment equal to nine months salary in the case of Mr. Clark, six months salary in the case of Messrs. Harless, Clement and Young and three months salary in the case of Mr. Burgess;
- a lump sum cash payment equal to all earned and unused vacation time for the previous year and the then current year;
- an assignment of his vested interests under our overriding royalty program, if eligible; and
- in the case of Messrs. Burgess and Clement, a lump sum payment equal to any unpaid bonus from prior years under our incentive compensation plan, plus, in lieu of any bonus for subsequent years, an amount equal to 25% of his base salary through the end of the remaining term of his employment agreement.

If a named executive officer's employment agreement is terminated by the named executive officer without good reason, the named executive officer gives notice of termination on the expiration of his term of employment or if we consent to a request by the named executive officer to terminate his employment agreement before the expiration of his term, he will be entitled to:

- the value of his salary and benefits through the date that his employment agreement is terminated;
- a lump sum cash payment equal to all earned and unused vacation time for the previous year and the then current year;
- an assignment of his vested interests in our overriding royalty program through the date of termination, if eligible; and
- in the case of Messrs. Burgess and Clement, a lump sum payment equal to any unpaid bonus from prior years under our incentive compensation plan, plus, in lieu of any bonus for subsequent years, an amount equal to 25% of his base salary through the end of the remaining term of his employment agreement.

If a named executive officer's employment agreement is terminated by us for cause, we will have no obligation to that employee other than to:

- pay his salary through the day of termination;
- pay him the value of his benefits under the employment agreement through the month of termination; and
- assign to him his vested interests in our overriding royalty program through the date of termination, if eligible.

To the extent any amounts paid under an employment agreement are subject to the "golden parachutes" excise tax, those amounts are grossed-up to cover the excise tax and any applicable taxes on the gross-up amount.

Each named executive officer has agreed that during the term of his employment agreement, and, if the named executive officer's employment agreement is terminated by us for cause or terminated by the named executive officer other than for good reason, for 12 months after the term expires in the case of Messr. Clark, and six months after the term expires in the case of Messrs. Harless, Clement, Burgess, and Young, they will not compete with us for business or hire our employees.

For purposes of the employment agreements with the named executive officers, "good reason" means:

- The assignment to the employee of any duties materially inconsistent with the employee s position, authority, duties or responsibilities with us or any other action that results in a material diminution in, or interference with, such position, authority, duties or responsibilities, if the assignment or action is not cured within 30 days after the employee has provided us with written notice;

- The failure to continue to provide the employee with office space, related facilities and support personnel (a) that are commensurate with the employee s responsibilities to, and position with, us and not materially dissimilar to the office space, related facilities and support personnel provided to our other employees having comparable responsibilities or (b) that are physically located at our principal executive offices, if that failure is not cured within 30 days after the employee has provided us with written notice;

- Any (a) reduction in the employee s monthly salary, (b) reduction in, discontinuance of, or failure to allow or continue to allow the employee s participation in, our incentive compensation program, or (c) reduction in, or failure to allow or continue the employee s participation in, any employee benefit plan in which the employee is participating or is eligible to participate before the reduction or failure, and that reduction, discontinuance or failure is not cured within 30 days after the employee has provided us with written notice;

- The relocation of the employee s or our principal office and principal place of the employee s performance of his duties and responsibilities to a location more than 50 miles outside of the central business district of Houston, Texas; or

- A breach of any material provision of the employment agreement that is not cured within 30 days after the employee has provided us with written notice.

In March of 2002, Mr. Clark, Mr. Harless, and Mr. Young terminated their employment agreements for "Good Reason" under terms as defined in their contracts.

Change of Control Agreements

We have issued each of the named executive officers' change of control agreements. Under these agreements, if a change of control occurs and the named executive officer's employment is terminated without cause or for good reason within 18 months of the change of control, Messr. Clark is entitled to receive, if the change in control is due to an acquisition of us by another company, three and one-half times his base salary and targeted annual incentive bonus, if applicable. Messrs. Harless, Clement, and Young are entitled to receive, if the change in control is due to an acquisition of us by another company, two times their base salary and targeted annual incentive bonus, if applicable. The severance payment will be calculated assuming we satisfy the applicable base target for a particular year for the targeted annual incentive bonus. The ultimate payment due under the change of control agreements will be the greater of the payment calculated under the change of control agreements or the compensation due for the remaining balance under the employment agreements. To the extent any amounts paid under the change in control agreements are subject to the "golden parachutes" excise tax, those amounts are grossed-up to cover the excise tax and any applicable taxes on the gross-up amount.

Overriding Royalty Program

Employees participating in our overriding royalty program receive incentive compensation in the form of overriding royalty interests in some of the oil and natural gas prospects we acquired. The aggregate overriding royalty interests do not exceed 1.5% of our working interest in these prospects before well payout or 6% of our working interest in these prospects after payout. An employee receives overriding royalty interests equal to specified undivided percentages of our working interest percentage in prospects we acquired within the United States and U.S. coastal waters during the term of the employee's employment.

The overriding royalty interest percentage of our working interest to which each named executive officer is entitled for the period before well payout is one-fourth of the overriding royalty interest percentage for the period after well payout. These percentages currently range from 0.09375% to 0.23250% before payout and from 0.37500% to 0.93000% after payout for the named executive officers.

If we propose to sell or farm out all or a portion of our working interest in a prospect to an unaffiliated third party and we determine in good faith that our interest will not be marketable on satisfactory terms if marketed subject to the named executive officer's overriding royalty interest affecting the prospect, we may adjust the named executive officer's overriding royalty interest in the prospect. These adjustments are determined by a committee designated by our board of directors, at least half of the members of which are individuals who have been granted an overriding royalty interest by us. Some committee decisions require the approval of our board of directors. These adjustments apply only to the portion of our working interest sold or farmed out to a third party and do not affect the named executive officer's overriding royalty interest in the portion of a prospect retained by us.

We may also elect, within 60 days after the end of our fiscal year, to reduce a named executive officer's overriding royalty interest in prospects that we acquired during the fiscal year. We must base these reductions on the levels of exploration and development costs related to these prospects actually incurred during the fiscal year. With respect to certain deepwater prospects, we also may elect, in our sole discretion, to make other reductions and adjustments to the employee's overriding royalty interest based on estimated exploration levels and development costs to be incurred in connection with these deepwater prospects. We retain a right of first refusal to purchase any overriding royalty interest assigned to a named executive officer. This right applies to any third-party offer received by the named executive officer during or within one year after the named executive officer's employment is terminated.

The following table shows distributions received during the applicable year by the named executive officers who are participants in the plan from overriding royalty interests we granted to the officers during the last 15 years.

	AGGREGATE CASH AMOUNTS RECEIVED FROM PREVIOUSLY ASSIGNED OVERRIDDING ROYALTY INTERESTS (1)		
	2001	2000	1999
Richard R. Clark	544,237	260,557	85,369
Gregory K. Harless	382,985	192,999	63,083
Thomas E. Young	189,059	74,502	9,513

1. For information on the value conveyed and distributions received, if any, during the applicable year attributable to overriding royalty interests assigned to the named executive officer during the applicable year, see the table under "Summary Compensation Table". The above amounts only include payments made by the Company. Certain participants also receive overrides from third parties.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Mariner is an indirect wholly owned subsidiary of Mariner Energy LLC. The following table sets forth the name and address of the only shareholder of Mariner Energy LLC that is known by the Company to beneficially own more than 5% of the outstanding common shares of Mariner Energy LLC, the number of shares beneficially owned by such shareholder, and the percentage of outstanding shares of common shares of Mariner Energy LLC so owned, as of March 1, 1999. As of March 1, 2001, there were 13,928,308 common shares of Mariner Energy LLC outstanding.

TITLE OF CLASS	NAME AND ADDRESS OF BENEFICIAL OWNER	NATURE OF BENEFICIAL OWNERSHIP	AMOUNT AND PERCENT OF CLASS
Common Stock of Mariner Energy LLC	Joint Energy Development Investments Limited Partnership (1) 1400 Smith Street Houston, Texas 77002	13,334,186	95.7%

1. JEDI primarily invests in and manages certain natural gas and energy related assets. JEDI's general partner is Enron Capital Management Limited Partnership, a Delaware limited partnership, whose general partner is Enron Capital Corp., a Delaware corporation and a wholly owned subsidiary of ENA, which is a wholly-owned subsidiary of Enron Corp. The general partner of JEDI exercises sole voting and investment power with respect to such shares.

The table appearing below sets forth information as of March 4, 2002, with respect common shares of Mariner Energy LLC beneficially owned by each of our directors, the named officers listed in the compensation table, a key consultant and all directors and executive officers and such key consultant as a group, and the percentage of outstanding common shares of Mariner Energy LLC so owned by each.

DIRECTORS, KEY CONSULTANT AND NAMED EXECUTIVE OFFICERS	AMOUNT AND NATURE OF BENEFICIAL OWNERSHIP (1)	PERCENT OF CLASS
Robert E. Henderson	84,840	*

DIRECTORS, KEY CONSULTANT AND NAMED EXECUTIVE OFFICERS	AMOUNT AND NATURE OF BENEFICIAL OWNERSHIP (1)	PERCENT OF CLASS
C. Ken Burgess	0	--
Richard R. Clark	61,440	*
Donald M. Clement, Jr.	12,000	*
Gregory K. Harless	13,200	*
David S. Huber	61,440	*
Michael W. Strickler	61,440	*
Thomas E. Young	15,600	*
All directors and executive officers consultant as a group (10 persons)	309,960	2.23%

* Less than one percent.

1. All shares are owned directly by the named person and such person has sole voting and investment power with respect to such shares.

Item 13. Certain Relationships and Related Party Transactions

The Acquisition, the Shareholders Agreement and Related Matters

Mariner Energy LLC, JEDI and each other shareholder of Mariner are parties to the Amended and Restated Shareholders' Agreement (as amended, the "Shareholders' Agreement").

Mariner Energy LLC has agreed to reimburse each Management Shareholder who paid for equity in Mariner's predecessor by assignment of overriding royalty interests for any additional taxes and related costs incurred by such Management Shareholder to the extent, if any, that the transfer of the overriding royalty interests does not qualify as a tax-free exchange under federal tax laws.

Enron and certain of its subsidiaries and other affiliates collectively participate in nearly all phases of the oil and natural gas industry and, therefore, compete with Mariner. In addition, ENA, JEDI and other affiliates of ENA have provided, and may in the future provide, and ECT Securities Limited Partnership, another affiliate of Enron, has assisted, and may in the future assist, in arranging financing to non-affiliated participants in the oil and natural gas industry who are or may become competitors of Mariner. Because of these various possible conflicting interests, the Shareholders' Agreement includes provisions designed to clarify that generally Enron and its affiliates have no duty to make business opportunities available to Mariner and no duty to refrain from conducting activities that may be competitive with us.

Under the terms of the Shareholders' Agreement, Enron and its affiliates (which include, without limitation, ENA and JEDI) are specifically permitted to compete with Mariner, and neither Enron nor any of its affiliates has any obligation to bring any business opportunity to Mariner.

Enron Bankruptcy - On December 2, 2001, Enron Corp. ("Enron") and one of its affiliates,Enron North America Corp. ("ENA"), among other affiliates filed voluntary petitions for bankruptcy protection. The Company has been informed that of the various affiliates of Enron to Mariner, only Enron and ENA are included in the bankruptcy. We do not know at this time if any other affiliates of Enron will seek bankruptcy protection or what effect, if any, this may have on Joint Energy Development Investments Limited Partnership ("JEDI") or the ownership of Mariner Energy LLC which owns 100% of our direct parent. Enron is the parent of ENA, and an affiliate of ENA is the general partner of JEDI. JEDI is 100% owned by several different Enron and ENA affiliates. Accordingly, Enron may be deemed to control JEDI, Mariner Energy LLC, Mariner Holdings and the Company. Additionally, seven of the Company's directors are officers of Enron or affiliates of Enron. Because of these various potentially conflicting interests, ENA, the Company, JEDI and the members of the Company's management who are also shareholders of Mariner Energy LLC have entered into an agreement that is intended to make clear that Enron and its affiliates have no duty to make business opportunities available to the Company.

Mariner Energy LLC's only asset is 100% of the common stock of Mariner Holdings, Inc., our direct parent. The only asset of Mariner Holdings is 100% of the common shares of Mariner. Covenants in Mariner's Revolving Credit Facility and Senior Subordinated Notes restrict the funds of Mariner that can be distributed to Mariner Energy LLC to repay its term loan to an ENA affiliate - see below "ENA Affiliate Term Loan". Mariner Energy LLC is currently attempting to obtain an extension of the ENA Affiliate Term Loan, but there can be no assurance that an extension will be obtained. In the event Mariner Energy LLC is unable to obtain an extension or restructure its obligations, it would either default or be forced to sell its interest in Mariner or cause Mariner to sell a substantial portion of its assets to repay its Revolving Credit Facility, if any amounts are outstanding, and outstanding Senior Subordinated Notes so that it could distribute any remaining cash proceeds to Mariner Energy LLC to be used to repay the

ENA Affiliate Term Loan.

As a result of the Enron and ENA bankruptcies, among other implications, as part of our normal operations we may not be able to obtain credit from banks or trade vendors or enter into hedging arrangements on acceptable terms. This may also hinder our ability to enter into certain transactions including purchase or sale arrangements and conduct significant capital programs.

Organization and Ownership of the Company - Through March 31, 1996, Hardy Oil & Gas USA Inc. (the "Predecessor Company") was a wholly-owned subsidiary of Hardy Holdings Inc., which is a wholly-owned subsidiary of Hardy Oil & Gas Plc ("Hardy Plc"), a company incorporated in the United Kingdom. Pursuant to a stock purchase agreement dated April 1, 1996, JEDI and ENA, together with members of management of the Predecessor Company, formed Mariner Holdings, Inc. ("Mariner Holdings"). Mariner Holdings then purchased from Hardy Holdings Inc. all of the issued and outstanding stock of the Predecessor Company for a purchase price of approximately $185.5 million (the "Acquisition"). After the Acquisition, the name of the Predecessor Company was changed to Mariner Energy, Inc. In October 1998, JEDI and other shareholders exchanged all of their common shares of Mariner Holdings, the Company's direct parent, for an equivalent ownership percentage in common shares of Mariner Energy LLC. Mariner Energy LLC owns 100% of Mariner Holdings.

The following chart represents our current ownership structure and affiliation with Enron entities.

Subsequent to the Acquisition, Mariner Energy LLC, Mariner Holdings and Mariner have each entered into various financing and operating transactions with affiliates. In addition the Company may have from time to time engaged in various commercial transactions and have various commercial relationships with Enron and certain affiliates of Enron, such as holding and exploring, exploiting and developing joint working interests in particular prospects and properties and entering into other oil and gas related or financial transactions. Certain of the Company's third-party debt instruments and arrangements restrict the Company's ability to engage in transactions with its affiliates, but those restrictions are subject to significant exceptions. The Company believes that its current agreements with Enron and its affiliates are, and anticipates that any future agreements with Enron and its affiliates will be, on terms no less favorable to the Company than would be obtained in an agreement with a third party. Below is a summary of key transactions between the Company and affiliate entities.

Mariner Energy LLC

ENA Credit Facility - In September 1998 Mariner Holdings established a credit facility to obtain additional capital. The credit facility, as subsequently amended and assigned to Mariner Energy LLC, provided for unsecured, subordinated loans of up to $50 million, bearing interest at LIBOR plus 4.5%, payable at April 30, 2000. The full amount borrowed under this credit facility was repaid on March 21, 2000 with proceeds from the ENA Affiliate Term Loan described below. The net proceeds from this facility were contributed to Mariner.

ENA Affiliate Term Loan - In March 2000, Mariner Energy LLC established an unsecured term loan with ENA to repay amounts outstanding under the ENA Credit Facility with Mariner Energy LLC ($50 million plus accrued interest) described above and Mariner's Senior Credit Facility with ENA ($25 million plus accrued interest), described below, and to provide additional working capital. The additional working capital of $55 million was contributed to Mariner in 2000. The loan bears interest at 15%, which interest accrues and is added to the loan principal. Repayment of the balance of loan principal and accrued interest, which was approximately $143 million as of December 31, 2001, is due March 20, 2003. As part of the loan agreement, two five-year warrants were issued to ENA providing the right to purchase up to 900,000 of common shares of Mariner Energy LLC for $0.01 per share.

We have been informed that the Term Loan was transferred from ENA to an ENA affiliate.

Mariner Holdings, Inc.

1998 Equity Investment - In June 1998, Mariner Holdings issued additional equity to its existing shareholders, including JEDI, for approximately $14.58 per share, for a net investment of $28.8 million, all of which was contributed to Mariner. Mariner Holdings paid approximately $1.2 million as a structuring fee, on a pro rata basis, to existing shareholders participating in this transaction. Approximately $1 million of this fee was paid to ECT Securities Limited Partnership.

Mariner Energy, Inc.

Senior Credit Facility with ENA - In April 1999 Mariner established a senior credit facility with ENA primarily to obtain additional working capital. The facility provided for senior unsecured revolving loans of up to $25 million, bearing interest at LIBOR plus 2.5%, payable quarterly. The full amount borrowed under the senior credit facility was repaid on March 21, 2000, with proceeds from the ENA Affiliate Term Loan described above.

Other Transactions

Oil and Gas Production Sales to ENA or Affiliates - During the three years ending December 31, 2001, 2000 and 1999, sales of oil and gas production to ENA or affiliates were $50.2 million, $73.4 million and $16.2 million, respectively. These sales were generally made on 1 to 3 month contracts. At the time ENA filed its petition for bankruptcy protection, the Company immediately ceased selling its physical production to ENA. As of December 31, 2001, we had an outstanding receivable for $3.0 million from ENA. This amount was not paid as scheduled and is still outstanding. The Company has estimated 90% of this balance is uncollectible and has recorded an allowance and related expense for $2.7 million.

Accounting for Price Risk Management Activities - Mariner engages in price risk management activities from time to time. These activities are intended to manage Mariner's exposure to fluctuations in commodity prices for natural gas and crude oil. The Company primarily utilizes price swaps and costless collars as a means to manage such risk. During 2001 and as of December 31, 2001, all of our hedging contracts were with ENA. As a result of ENA's bankruptcy, the contracts are currently in default. The November and December settlements for oil and gas have not been collected, and there is significant uncertainty that the $4.0 million owed to the Company for the November and December settlements or any future settlements will be collected. As a result of the default, the Company has recorded an allowance representing 90% of the recorded hedge settlements receivable of $4.0 million, fair market value of the derivative assets of $25.8 (as of December 2, 2001), and accounts receivable for oil and gas sales of $3.0 million. Reflected in the earnings of the Company for the period ended December 31, 2001 is a loss for impairment of Enron related receivables of $29.5 million. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137 and No. 138, we have de designated our contracts effective December 2, 2001 and are recognizing all market value changes subsequent to such de-designation in earnings of the Company. The value recorded up to the time of de-designation and included in Accumulated Other Comprehensive Income ("AOCI"), will reverse out of AOCI and into earnings as the original corresponding production, as hedged by the contracts, is produced. As of December 31, 2001, $25.8 million remained in AOCI to be reversed out during the contract periods covering January 1, 2002 through December 31, 2003. Due to the uncertainty of future settlements, the overall effect of the ENA bankruptcy has been to eliminate our commodity price hedge protection.

The following table sets forth the results of hedging transactions during the periods indicated. For the year ended December 31, 2001, the amounts are reflective of the results up to the point of de-designation (December 2, 2001), which include all settled contract months through December of 2001:

The following table sets forth the results of hedging transactions during the periods indicated:

	YEAR ENDING DECEMBER 31,		
	2001	**2000**	**1999**
Natural gas quantity hedged (Mmbtu)	17,733	19,569	18,818
Increase (decrease) in natural gas sales (thousands)	$(5,523)	($21,364)	($6,741)
Crude oil quantity hedged (MBbls)	752	1,059	389
Increase (decrease) in crude oil sales (thousands)	$2,393	($14,053)	($2,152)

The following table sets forth our open positions as of December 31, 2001.

TIME PERIOD	**NOTIONAL QUANTITIES**	**FIXED PRICE**	**FAIR VALUE (in millions)**
NATURAL GAS (MMBTU)			
January 1 - October 31, 2002			
Fixed price swap purchased	1,831	$2.18	$(0.9)
January 1 - December 31, 2002			
Fixed price swap purchased	12,134	4.43	20.4
April 1 - December 31, 2002			

TIME PERIOD	NOTIONAL QUANTITIES	FIXED PRICE	FAIR VALUE (in millions)
Fixed price swap purchased	4,125	3.03	0.9
January 1 - December 31, 2003			
Fixed price swap purchased	3,650	3.74	2.0
CRUDE OIL (MBBL)			
January 1 - June 30, 2002			
Fixed price swap purchased	181	25.15	0.9
January 1 - December 31, 2002			
Fixed price swap purchased	365	25.48	1.9
Sub-Total			$25.2(1)
Allowance for impairment			$(22.7)
Total			$2.5

1. Subsequent to the date of default by Enron and ENA, and as of December 31, 2001, the contracts decreased in gross market value by $523,000, which is reflected in the impairment of related party receivables at the net valuation of 10% or $52,000, after consideration for allowance.

Transportation Contract - In 1999 the Company constructed a 29 mile flowline from a third party platform to the Mississippi Canyon 718 subsea well. After commissioning, MEGS LLC, an Enron affiliate that is not in bankruptcy, purchased the flowline from the Company and its joint interest partners. The Company received $8.8 million in cash proceeds that were offset against the cost of constructing the flowline. No gain or loss was recognized. In addition, the Company entered into a firm transportation contract with MEGS LLC at a rate of $0.26 per Mmbtu to transport the Company's share of 86 Bcf of natural gas from the commencement of production through March 2009. The Company's working interest in the well at December 31, 2001 was 51%. For the year ending December 31, 2001, the Company paid $4.2 million on this contract. The remaining volume commitment is 30.8 Bbtu or $7.9 million net to the Company. Pursuant to the contract, the Company must deliver minimum quantities through the flowline or be subject to minimum monthly payment requirements. Throughout 2001 the Company failed to meet these minimum requirements and paid $1.5 million relating to the shortfall. The Company estimates that future production will also fail to meet minimum delivery requirements and has accrued $972,000 for future shortfalls.

Services Agreement - In conjunction with the change of certain key management positions, the Company entered into a services agreement for ENA to provide certain administrative services. The Company is obligated to pay $45,000 per month under this agreement.

Supplemental Affiliate Data - Provided below is supplemental balance sheet and income statement amounts for affiliate entities:

	YEAR ENDED DECEMBER 31,	
	2001	**2000**

	YEAR ENDED DECEMBER 31,			
BALANCE SHEET DATA	**AMOUNTS (in millions)**		**AMOUNTS (in millions)**	
RELATED PARTY RECEIVABLE:				
Derivative Asset	$2.5			
Settled Hedge Receivable	0.4			
Oil and Gas Receivable	0.3	$3.2	$6.9	$6.9
ACCURED LIABILITIES:				
Transportation Contract	$0.9		--	
Service Agreement	$0.3	$1.2	--	--
STOCKHOLDERS' EQUITY:				
Common Stock	$0.001		$0.001	
Additional Paid-in Capital	$227.3	$227.3	$227.3	$227.3
INCOME STATEMENT DATA				
Oil and Gas Sales	$50.2		$73.4	
General and Administrative Expenses	0.2		--	
Transportation Expenses	4.2		3.7	
Impairment of Enron Related Receivables	29.5		--	

Under the Revolving Credit Facility, Mariner has covenanted that it will not engage in any transaction with any of its affiliates (including Enron, ENA, JEDI and affiliates of such entities) providing for the rendering of services or sale of property unless such transaction is as favorable to such party as could be obtained in an arm's-length transaction with an unaffiliated party in accordance with prevailing industry customs and practices. The Revolving Credit Facility excludes from this covenant (i) any transaction permitted by the Shareholders' Agreement, (ii) the grant of options to purchase or sales of equity securities to directors, officers, employees and consultants of Mariner and (iii) the assignment of any overriding royalty interest pursuant to an employee incentive compensation plan.

The Indenture, dated as of August 1, 1996, between Mariner and United States Trust Company of New York (the "Indenture"), under which the Senior Subordinated Notes were issued, contains similar restrictions. Under the Indenture, Mariner has covenanted not to engage in any transaction with an affiliate unless the terms of that transaction are no less favorable to Mariner than could be obtained in an arm's-length transaction with a nonaffiliate. Further, if such transaction involves more than $1 million, it must be approved in writing by a majority of Mariner's disinterested directors, and if such a transaction involves more than $5 million, it must be determined by a nationally recognized banking firm to be fair, from a financial standpoint, to Mariner. However, this covenant is subject to several significant exceptions, including, among others, (i) certain industry-related agreements made in the ordinary course of business where such agreements are approved by a majority of Mariner's disinterested directors as being the most favorable of several bids or proposals, (ii) transactions under employment agreements or compensation plans entered into in the ordinary course of business and consistent with industry practice and (iii) certain prior transactions.

PART IV

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K.

(a) Document included in this report:

1. Financial Statements and **2. Financial Statement Schedules**

These documents are listed in the Index to Financial Statements in Item 8 hereof.

3. Exhibits

Exhibits designated by the symbol * have been previously filed on prior years Form 10-K. All exhibits not so designated are incorporated by reference to a prior filing as indicated.

PART IV

Exhibits designed by the symbol ** are filed with this Annual Report on Form 10-K.

Exhibits designated by the symbol are management contracts or compensatory plans or arrangements that are required to be filed with this report pursuant to this Item 14.

The Company undertakes to furnish to any stockholder so requesting a copy of any of the following exhibits upon payment to the Company of the reasonable costs incurred by Company in furnishing any such exhibit.

3.1*	Amended and Restated Certificate of Incorporation of the Registrant, as amended.
3.2*	Bylaws of Registrant, as amended.
4.1(a)	Indenture, dated as of August 1, 1996, between the Registrant and United States Trust Company of New York, as Trustee.
4.2(d)	First Amendment to Indenture, dated as of January 31, 1998, between the Registrant and United States Trust Company of New York, as Trustee.
4.3(a)	Note, dated August 12, 1996, in the principal amount of up to $45,000,000, made by the Registrant in favor of Nations Bank of Texas, N.A.
4.4(a)	Note, dated August 12, 1996, in the principal amount of up to $45,000,000, made by the Registrant in favor of Toronto Dominion (Texas), Inc.
4.5(a)	Note, dated August 12, 1996, in the principal amount of up to $30,000,000, made by the Registrant in favor of The Bank of Nova Scotia.
4.6(a)	Note, dated 12, 1996, in the principal amount of up to $30,000.000, made by the Registrant in favor of ABN AMRO Bank, N.V., Houston Agency.
4.7(a)	Form of the Registrant's 10 1/2% Senior Subordinated Note Due 2006, Series B.
4.8*	Credit and Subordination Agreement dated as of September 2, 1998 between Mariner Holdings, Inc. and Enron Capital & Trade Resources Corp.
4.9(f)	Amended and Restated Credit Agreement, dated June 28, 1999, among Mariner Energy, Inc., NationsBank of Texas, N.A., as Agent, Toronto Dominion (Texas), Inc., as Co-agent, and the financial institutions listed on schedule 1 thereto.
4.10(f)	Second Amended and Restated Credit Agreement, dated as of April 15, 1999, between Mariner Energy LLC and Enron North America Corp. (formerly Enron Capital & Trade Resources Corp.).
4.11(f)	Revolving Credit Agreement dated as of April 15, 1999, between Mariner Energy, Inc. and Enron North America Corp. (formerly Enron Capital & Trade Resources Corp.).
4.12**	Term Loan Agreement, dated March 21, 2000, between Mariner Energy LLC and Enron North America Corp.
10.1*	Amended and Restated Shareholders' Agreement, dated October 12, 1998, among Mariner Energy LLC, Enron Capital & Trade Resources Corp., Mariner Holdings, Inc., Joint Energy Development Investments Limited Partnership and the other shareholders of Mariner Energy LLC.
10.2*	Gas Gathering Agreement, dated December 29, 1999, between MEGS LLC, Mariner Energy, Inc. and Burlington Resources.
10.3(f)	Amended and Restated Credit Agreement, dated June 28, 1999, between Mariner Energy and Bank of America, N.A.
10.10(a) +	Amended and Restated Consulting Services Agreement, dated June 27, 1996, between the Registrant and David S. Huber.
10.11(a) +	Mariner Holdings, Inc. 1996 Stock Option Plan (assumed by Mariner Energy LLC).
10.12(a) +	Form of Incentive Stock Option Agreement (pursuant to the Mariner Holdings, Inc. 1996 Stock Option Plan, assumed by Mariner Energy LLC).
10.13**	List of executive officers who are parties to an Incentive Stock Option Agreement.
10.14(a) +	Form of Nonstatutory Stock Option Agreement (pursuant to the Mariner Holdings, Inc. 1996 Stock Option Plan, assumed by Mariner Energy LLC).
10.15**	List of executive officers who are parties to a Nonstatutory Stock Option Agreement.
10.16(a) +	Nonstatutory Stock Option Agreement, dated June 27, 1996, between the Registrant and David S. Huber.
10.23(e) +	First Amendment to Amended and Restated Consulting Services Agreement, effective as of October 1, 1999, between Mariner Energy, Inc. and David S. Huber.

PART IV

10.28(g)	Gas Gathering Agreement, dated December 29, 1999 between MEGS, LLC and Mariner Energy, Inc. and Burlington Resources, Inc.
10.29(g)	First Amendment to Amended and Restated Credit Agreement, dated December 31, 1999 by and among Mariner Energy, Inc., Bank of America, N.A., Toronto Dominion (Texas), Inc., Bank of Nova Scotia, and ABN-AMRO Bank, N.V.
10.30** +	Second Amendment to Amended and Restated Consulting Services Agreement, effective as of January 1, 2000, between Mariner Energy, Inc. and David S. Huber.
10.31** +	Third Amendment to Amended and Restated Consulting Services Agreement, effective as of March 4, 2002, between Mariner Energy, Inc. and David S. Huber.
10.32** +	Employment Agreement, dated October 5, 1998, between the Registrant and C. Ken Burgess.
10.33** +	First Amendment to Employment Agreement, dated October 1, 1999, between the Registrant and C. Ken Burgess.
10.34** +	Second Amendment to Employment Agreement, dated January 1, 2000, between the Registrant and C. Ken Burgess.
10.35** +	Third Amendment to Employment Agreement, dated January 1, 2001, between the Registrant and C. Ken Burgess.
10.36** +	Fourth Amendment to Employment Agreement, dated September 1, 2001, between the Registrant and C. Ken Burgess.
10.37** +	Amended and Restated Employment Agreement, dated August 4, 1998, between the Registrant and Michael A. Wichterich.
10.38** +	Employment Agreement, dated December 4, 2001, between the Registrant and Michiel C. van den Bold.
10.39**	Corporate Services Agreement, dated August 23, 2001, between the Mariner Energy, Inc. and Enron North America Corp.
17.1**	Letter of Resignation from the Board of Directors from D. Brad Dunn, dated February 23, 2001.
17.2**	Letter of Resignation from the Board of Directors from Jere C. Overdyke, dated February 23, 2001.
17.3**	Letter of Resignation from the Board of Directors from L. V. (Bud) McGuire, dated September 21, 2001.
17.4**	Letter of Resignation from the Board of Directors from C. John Thompson, dated November 27, 2001.
17.5**	Letter of Resignation from the Board of Directors from Mark F. Haedicke, dated February 8, 2002.
17.6**	Letter of Resignation from the Board of Directors from Rick Buy, dated February 11, 2002.
23.1**	Consent of Ryder Scott Company.
23.2**	Ryder Scott Company Letter of Estimated Proved Reserves dated February 23, 2001.
(a)	Incorporated by reference to the Company's Registration Statement on Form S-4 (Registration No. 333-12707), filed September 25, 1996.
(b)	Incorporated by reference to Amendment No. 1 to the Company's Registration Statement on Form S-4 (Registration No. 333-12707), filed December 6, 1996.
(c)	Incorporated by reference to Amendment No. 2 to the Company's Registration Statement on Form S-4 (Registration No. 333-12707), filed December 19, 1996.
(d)	Incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 1996 (Registration No. 333-12707) filed March 31, 1997.
(e)	Incorporated by reference to the Mariner Energy LLC November 4, 1999 filing on Forms S-1 (Registration No. 333-87287).
(f)	Incorporated by reference to the Mariner Energy, Inc. March 31, 2001, June 30, 2001 or September 30, 2001 quarterly filings on Form 10-Q.
(g)	Incorporated by reference to the Mariner Energy Inc. December 31, 2001 annual filing on form 10-K.

(b) **Reports on Form 8-K:**

The Company filed no reports on Form 8-K during the quarter ended December 31, 2001.

GLOSSARY

The terms defined in this glossary are used throughout this annual report.

Bbl. One stock tank barrel, or 42 U.S. Gallons liquid volume, used herein in reference to crude oil, condensate or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas. Bcfe. One billion cubic feet of natural gas equivalent (see Mcfe for equivalency).

"behind the pipe" Hydrocarbons in a potentially producing horizon penetrated by a well bore the production of which has been postponed pending the production of hydrocarbons from another formation penetrated by the well bore. These hydrocarbons are classified as proved but non-producing reserves.

2-D. (Two-Dimensional Seismic) -- Geophysical data that depicts the subsurface strata in two dimensions.

3-D. (Three-Dimensional Seismic) -- Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than can be achieved using 2-D seismic.

"development well" A well drilled within the proved boundaries of an oil or natural gas reservoir with the intention of completing the stratigraphic horizon known to be productive.

"exploitation well" Ordinarily considered to be a development well drilled within a known reservoir. The Company uses the word to refer to Deepwater wells which are drilled on offshore leaseholds held (usually under farmout agreements) where a previous exploratory well showing the existence of potentially productive reservoirs was drilled, but the reservoir was by-passed for development by the owner who drilled the exploratory well; Thus the Company distinguishes its development wells on its own properties from such exploitation wells.

"exploratory well" A well drilled in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial petroleum deposit and which can be contrasted with a "development well".

"farm-in" A term used to describe the action taken by the person to whom a transfer of an interest in a leasehold in an oil and gas property is made pursuant to a farmout agreement.

"farmout" The term used to describe the action taken by the person making a transfer of a leasehold interest in an oil and gas property pursuant to a farmout agreement.

"farmout agreement" A common form of agreement between oil and gas operators pursuant to which an owner of an oil and gas leasehold interest who is not desirous of drilling at the time agrees to assign the leasehold interest, or some portion of it, to another operator who is desirous of drilling the tract. The assignor in such a transaction may retain some interest in the property such as an overriding royalty interest or a production payment, and, typically, the assignee of the leasehold interest has an obligation to drill one or more wells on the assigned acreage as a prerequisite to completion of the transfer to it.

"generate" Generally refers to the creation of an exploration or exploitation idea after evaluation of seismic and other available data.

"infill well" A well drilled between known producing wells to better exploit the reservoir.

"lease operating expenses" The expenses of lifting oil or gas from a producing formation to the surface, and the transportation and marketing thereof, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, ad valorem taxes and other expenses incidental to production, but not including lease acquisition, drilling or completion expenses or other "finding costs".

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalent (converting one barrel of oil to six Mcf of natural gas based on commonly accepted rough equivalency of energy content).

MMBTU. One million British thermal units.

MMcf. One million cubic feet of natural gas.

MMcfe. One million cubic feet of natural gas equivalent (see Mcfe for equivalency).

NYMEX. New York Mercantile Exchange.

"payout" Generally refers to the recovery by the incurring party to an agreement of its costs of drilling, completing, equipping and operating a well before another party's participation in the benefits of the well commences or is increased to a new level.

"present value of estimated future net revenues" An estimate of the present value of the estimated future net revenues from proved oil and gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with Securities and Exchange Commission practice, to determine their "present value". The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the date indicated and held constant for the life of the reserves.

"producing well" or "productive well" A well that is producing oil or natural gas or that is capable of production without further capital expenditure.

"proved developed reserves" Proved developed reserves are those quantities of crude oil, natural gas and natural gas liquids that, upon analysis of geological and engineering data, are expected with reasonable certainty to be recoverable in the future from known oil and natural gas reservoirs under existing economic and operating conditions. This classification includes: (a) proved developed producing reserves, which are those expected to be recovered from currently producing zones under continuation of present operating methods; and (b) proved developed non-producing reserves, which consist of (i) reserves from wells that have been completed and tested but are not yet producing due to lack of market or minor completion problems that are expected to be corrected, and (ii) reserves currently behind the pipe in existing wells which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the well.

"proved reserves" The estimated quantities of crude oil, natural gas and other hydrocarbon liquids 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 undeveloped reserves" Proved reserves that may be expected to be recovered from existing wells that will require a relatively major expenditure to develop or from undrilled acreage adjacent to productive units that are reasonably certain of production when drilled.

"royalty interest" An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage or of the proceeds from the sale thereof. Such an interest generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalty interests may be either landowner's royalty interests, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalty interests, which are usually carved from the leasehold interest pursuant to an assignment to a third party or reserved by an owner of the leasehold in connection with a transfer of the leasehold to a subsequent owner.

"subsea tieback" A productive well that has its wellhead equipment located on the sea floor and is connected by control and flow lines to an existing production platform located in the vicinity.

"unitized" or "unitization" Terms used to denominate the joint operation of all or some portion of a producing reservoir, particularly where there is separate ownership of portions of the rights in a common producing pool, in order to carry on certain production techniques, maximize reservoir production and serve conservation interests economically.

"working interest" The interest in an oil and gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct oil and gas operations on the property and to a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

SIGNATURES

The registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

April 16, 2002

MARINER ENERGY, INC.

SIGNATURES

by:

/s/ Allan Keel
Allan Keel,
President and Chief Executive Officer

This report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

SIGNATURE	TITLE	DATE
/s/ Scott D. Josey Scott D. Josey	Chairman of the Board	April 16, 2002
/s/ Allan D. Keel Allan D. Keel	President and Chief Executive Officer	April 16, 2002
/s/ Michael A. Wichterich Michael A. Wichterich	Vice President of Finance & Administration	April 16, 2002
/s/ C. Ken Burgess C. Ken Burgess	Vice President of Drilling & Production	April 16, 2002
/s/ Mike van den Bold Mike van den Bold	Vice President of Development	April 16, 2002
/s/ Kelly D. Zelikovitz Kelly D. Zelikovitz	General Counsel and Secretary	April 16, 2002
/s/ David S. Huber David S. Huber	Consultant and Director of Deepwater Drilling	April 16, 2002

SIGNATURES

/s/ Robert E. Henderson Robert E. Henderson	Director	April 16, 2002
/s/ Michael W. Strickler Michael W. Strickler	Director	April 16, 2002
/s/ Craig A. Fox Craig A. Fox	Director	April 16, 2002
/s/ Jesus G. Melendrez Jesus G. Melendrez	Director	April 16, 2002
/s/ Raymond M. Bowen, Jr. Raymond M. Bowen, Jr.	Director	April 16, 2002
/s/ Jeffrey McMahon Jeffrey McMahon	Director	April 16, 2002
/s/ Robert H. Walls, Jr. Robert H. Walls, Jr.	Director	April 16, 2002

Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act

No annual report covering the Registrant's last fiscal year or proxy statement, form of proxy or other proxy soliciting material with respect to any annual or other meeting of security holders has been sent to the Company's security holders.