MARINER ENERGY INC
Form S-1
May 12, 2005

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As filed with the Securities and Exchange Commission on May 12, 2005

Registration No. 333-

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

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

Mariner Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**1311**	**86-0460233**
(State or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

2101 Citywest Blvd., Suite 1900
Houston, Texas 77042
(713) 954-5500
(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

Teresa Bushman
Vice President and General Counsel
Mariner Energy, Inc.
2101 Citywest Blvd., Suite 1900
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(713) 954-5505
(Name, address, including zip code, and telephone number, including area code, of agent for service)

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Approximate date of commencement of proposed sale to the public: From time to time after the effective date of this registration statement.

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

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

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

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

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

CALCULATION OF REGISTRATION FEE

Title of each class of securities to be registered	Amount to be registered	Proposed maximum offering price per share(1)	Proposed maximum aggregate offering price(1)	Amount of registration fee
Common stock, par value $.0001 per share	33,348,130	$14.25	$475,210,852.50	$55,932.32

(1) Estimated solely for the purpose of calculating the registration fee under Rule 457(c) under the Securities Act. No exchange or over-the-counter-market exists for the registrant s common stock; however, shares of the registrant s common stock issued to qualified institutional buyers in connection with its March 2005 private equity placement are eligible for the PORTAL Market®. The last sale of shares of the registrant s common stock that was eligible for PORTAL, of which the registrant is aware, occurred on May 9, 2005 at a price of $14.25.

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

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The information in this prospectus is not complete and may be changed. These securities may not be sold until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

Subject to Completion dated May 12, 2005

PROSPECTUS

33,348,130 Shares
Common Stock

This prospectus relates to up to 33,348,130 shares of the common stock of Mariner Energy, Inc., which may be offered for sale by the selling stockholders named in this prospectus. The selling stockholders acquired the shares of common stock offered by this prospectus in private equity placements. We are registering the offer and sale of the shares of common stock to satisfy registration rights we have granted.

We are not selling any shares of common stock under this prospectus and will not receive any proceeds from the sale of common stock by the selling stockholders. The shares of common stock to which this prospectus relates may be offered and sold from time to time directly from the selling stockholders or alternatively through underwriters or broker-dealers or agents. The shares of common stock may be sold in one or more transactions, at fixed prices, at prevailing market prices at the time of sale or at negotiated prices. Please read Plan of Distribution.

Prior to this offering, there has been no public market for our common stock. We intend to apply to list our common stock on The Nasdaq Stock Market under the symbol .

Investing in our common stock involves risks. You should read the section entitled Risk Factors beginning on page 7 for a discussion of certain risk factors that you should consider before investing in our common stock.

You should rely only on the information contained in this prospectus or any prospectus supplement or amendment. We have not authorized anyone to provide you with different information. We are not making an offer of these securities in any state where the offer is not permitted.

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

The date of this prospectus is , 2005.

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WHERE YOU CAN FIND INFORMATION

We have filed with the SEC, under the Securities Act of 1933, as amended (the Securities Act), a registration statement on Form S-1 with respect to the common stock offered by this prospectus. This prospectus, which constitutes part of the registration statement, does not contain all the information set forth in the registration statement or the exhibits and schedules which are part of the registration statement, portions of which are omitted as permitted by the rules and regulations of the SEC. Statements made in this prospectus regarding the contents of any contract or other documents are summaries of the material terms of the contract or document. With respect to each contract or document filed as an exhibit to the registration statement, reference is made to the corresponding exhibit. For further information pertaining to us and to the common stock offered by this prospectus, reference is made to the registration statement, including the exhibits and schedules thereto, copies of which may be inspected without charge at the public reference facilities of the SEC at 450 Fifth Street, N.W., Washington, D.C. 20549. Copies of all or any portion of the registration statement may be obtained from the SEC at prescribed rates. Information on the public reference facilities may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a web site that contains reports, proxy and information statements and other information that is filed electronically with the SEC. The web site can be accessed at *www.sec.gov.*

Upon completion of this offering, we will be required to comply with the informational requirements of the Securities Exchange Act of 1934, as amended (the Exchange Act), and, accordingly, will file current reports on Form 8-K, quarterly reports on Form 10-Q, annual reports on Form 10-K, proxy statements and other information with the SEC. Those reports, proxy statements and other information

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will be available for inspection and copying at the public reference facilities and internet site of the SEC referred to above.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

We are including the following discussion to inform you of some of the risks and uncertainties that can affect our company and to take advantage of the safe harbor protection for forward-looking statements that applicable federal securities law affords.

Various statements this prospectus contains, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future production, revenues, income and capital spending. Our forward-looking statements are generally accompanied by words such as estimate, project, predict, believe, expect, anticipate, potential, plan, goal or other words that convey future events or outcomes. The forward-looking statements in this prospectus speak only as of the date of this prospectus; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- the volatility of oil and natural gas prices;
- discovery, estimation, development and replacement of oil and natural gas reserves;
- cash flow and liquidity;
- financial position;
- business strategy;
- amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- operating costs and other expenses;
- prospect development and property acquisitions;
- marketing of oil and natural gas;
- competition in the oil and natural gas industry;
- governmental regulation of the oil and natural gas industry; and
- developments in oil-producing and natural gas-producing countries.

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SUMMARY

This summary highlights selected information from this prospectus, but does not contain all information that you should consider before investing in the shares. You should read this entire prospectus carefully, including the Risk Factors beginning on page 7 of this prospectus and the financial statements included elsewhere in this prospectus. References to Mariner, the Company, we, us, and our refer to Mariner Energy, Inc. The estimates of our proved reserves as of December 31, 2002, 2003 and 2004 included in this prospectus are based on reserve reports prepared by Ryder Scott Company, L.P., independent petroleum engineers (Ryder Scott). A summary of their report on our proved reserves as of December 31, 2004 is attached to this prospectus as Appendix A. We have provided definitions for some of the industry terms used in this prospectus in the Glossary of Oil and Natural Gas Terms beginning on page 80 of this prospectus.

About Mariner Energy, Inc.

We are an independent oil and gas exploration, development and production company with principal operations in the Gulf of Mexico, both shelf and deepwater, and the Permian Basin in West Texas. As of December 31, 2004, we had 237.5 Bcfe of proved reserves, of which approximately 64% were natural gas and 36% were oil and condensate. The estimated present value of future net revenues from proved reserves before income taxes, using SEC pricing guidelines, and discounted at an annual rate of 10% (PV10), as of December 31, 2004 was approximately $668 million. As of December 31, 2004, approximately 46% of our proved reserves were classified as proved developed. For the year ended December 31, 2004, our total net production was 37.6 Bcfe. We believe our proved reserve base is balanced, with 48% of the reserves located in the Permian Basin in West Texas, 37% in the Gulf of Mexico deepwater and 15% on the Gulf of Mexico shelf as of December 31, 2004. In the three-year period ended December 31, 2004, we deployed approximately $337.3 million of capital on acquisitions, exploration and development while adding approximately 190.8 Bcfe of proved reserves and producing approximately 110.7 Bcfe.

Summary of Geographic Areas of Activities

The following table sets forth the estimated quantities of proved reserves attributable to our principal operating regions as of December 31, 2004.

	Estimated Proved Reserves(1)				
	Oil (MMbbls)	**Natural Gas (Bcf)**	**Total (Bcfe)**	**Percent of Reserves**	**PV10 Value(2) (millions)**
West Texas Permian Basin	8.7	62.8	114.8	48%	$ 206
Gulf of Mexico Deepwater(3)	4.5	59.8	86.7	37%	311
Gulf of Mexico Shelf(4)	1.1	29.3	36.0	15%	151
Total	14.3	151.9	237.5	100%	$ 668

(1) These estimates are based upon a reserve report prepared by Ryder Scott using criteria in compliance with SEC guidelines. A summary of their report is attached as Appendix A to this prospectus.

(2) Our PV10 value has been calculated using NYMEX prices at December 31, 2004, of $43.45 per bbl of oil and $6.15 per MMBtu of natural gas, as adjusted for appropriate regional price differentials.

(3) Deepwater refers to water depths greater than 1,300 feet (the approximate depth of deepwater designation for royalty purposes by the U.S. Minerals Management Service (the MMS)).

(4) Shelf refers to water depths less than 1,300 feet and includes an insignificant amount of Gulf Coast onshore properties.

The distribution of our proved reserves reflects our efforts over the last three years to diversify our asset base, which in prior years had been focused primarily in the Gulf of Mexico deepwater. We have shifted some of our focus on deepwater activities to increased exploration and development on the Gulf of Mexico shelf and exploitation of our West Texas Permian Basin properties. By allocating our resources among these three areas, we expect to balance the risks associated with the exploration and developments of our asset base. We intend to continue to pursue moderate-risk exploratory and development drilling projects in the Gulf of Mexico deepwater and on the Gulf of Mexico shelf, and also target low-risk infill drilling projects in West Texas. It is our practice to generate most of our prospects internally, but from time to time we also acquire third-party generated prospects. We then drill to find oil and natural gas reserves, a process that we refer to as growth through the drill bit.

West Texas Permian Basin

We operate and own working interests in individual wells ranging from 33% to 84% (with an average working interest of approximately 66.5%) in the 18,500-acre Aldwell Unit. As of December 31, 2004, the Aldwell Unit and nearby North Stiles unit accounted for 48%, or 114.8 Bcfe, of our proved reserves. The Aldwell Unit is located in the heart of the Spraberry geologic trend southeast of Midland, Texas, and has produced oil and gas since 1949. We began our recent redevelopment of the Aldwell Unit by drilling eight wells in the fourth quarter of 2002, 43 wells in 2003, and 54 wells in 2004. We have accelerated our development program and anticipate drilling an additional 60-70 wells in the Aldwell Unit during 2005. As of March 31, 2005, 17 of these additional wells have been drilled. All of our drilling in Aldwell has resulted in commercially successful wells. As of December 31, 2004, there were a total of 185 wells producing or capable of producing in the field. Our aggregate net capital expenditures for the 2004 drilling program were approximately $20.3 million. As of December 31, 2004, the average reserve-to-production ratio for our proved reserves in this area was approximately 22 years.

Gulf of Mexico Deepwater

We have interests in nine fields in the Gulf of Mexico deepwater, three of which we operate. The Gulf of Mexico deepwater accounts for 37%, or 86.7 Bcfe, of our December 31, 2004 proved reserves. Our net production from deepwater wells for December 2004 averaged approximately 44 MMcfe per day. As of March 31, 2005, we held interests in 53 Gulf of Mexico blocks with water depths of over 1,300 feet and had approximately 125,000 net undeveloped acres under lease. In 2004, we spent approximately $63.5 million net on drilling and completion activities in the deepwater. We drilled five exploratory wells, four of which were successful, and one development well, which was also successful.

In 2004, four subsea tiebacks were in the development phase in the deepwater: Mississippi Canyon 718 (Pluto), Viosca Knoll 917 (Swordfish), Green Canyon 178 (Baccarat) and Mississippi Canyon 296 (Rigel). These four subsea tieback projects contain approximately 49 Bcfe of proved reserves as of December 31, 2004. Currently, production is expected to commence from all four projects in 2005. Swordfish, Baccarat and Rigel are the results of Mariner-generated prospects. The Swordfish and Pluto projects are operated by Mariner, and the Baccarat and Rigel projects are operated by other working interest owners.

Gulf of Mexico Shelf

In the past two years, we have increased our drilling activities on the Gulf of Mexico shelf. As of March 31, 2005, we held interests in 22 fields on the Gulf of Mexico shelf, seven of which we operate. Gulf of Mexico shelf properties comprise 15%, or 36 Bcfe, of our proved reserves as of December 31, 2004. Our net production from these wells for December 2004 averaged approximately 35 MMcfe per day. As of March 31, 2005, we held interests in 59 Gulf of Mexico shelf blocks and had approximately 90,000 net undeveloped acres under lease. During 2004, we spent approximately $38.3 million to drill nine exploratory wells, three of which were successful, and two development wells, one of which was successful, on the Gulf of Mexico shelf.

First production from our Ewing Bank 977 (Dice) project, a subsea tieback, and High Island 46 (Green Pepper) commenced in January 2005. First production from our two West Cameron 333 wells (Royal Flush) commenced during February 2005.

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Recent Developments

Operations. During the first quarter of 2005, we drilled 17 wells in the Aldwell Unit, all of which were successful. A third party currently gathers, compresses and processes our gas from the Aldwell Unit under a contract that will expire on June 1, 2005. We have begun construction of our own oil and gas gathering lines and compression facilities, which we expect to complete by June 1, 2005, and have entered into a contract with a third party to provide processing of our natural gas. We are also negotiating a new oil transportation agreement. We expect these arrangements to improve the economics of production from the Aldwell Unit.

In the March 2005 Central Gulf of Mexico federal lease sale, we were the high bidder on two blocks located in water depths of 85 feet and 635 feet, respectively. We have been awarded one of the blocks and await an MMS decision on the second block. We are currently participating in drilling operations on two offshore exploratory prospects.

Our current capital budget for 2005 totals approximately $152 million. This number will likely change as a result of a number of factors, including new drilling and acquisition opportunities that may arise, costs of drilling and completion, availability of drilling rigs, equipment and labor, availability of capital, drilling results and oil and natural gas prices.

Production. Final reported production for the month of December 2004 averaged approximately 92 MMcfe per day. During the first quarter of 2005, we added new production from three shelf projects High Island 46 (Green Pepper), Ewing Bank 977 (Dice) and West Cameron 333 (Royal Flush), as well as additional wells at our onshore Aldwell Unit. The production from the new wells was sufficient to maintain our total production rate at approximately 92 MMcfe per day for the first quarter of 2005. Production at the three projects has been stabilized at combined rates of approximately 9 MMcfe per day net to the Company. However, the Dice project is producing at relatively low rates from a zone that appears to be compartmentalized. We expect to sidetrack the Dice well later in the year to access a better location in the producing horizon.

New production from our Pluto and Swordfish deepwater development projects and our Ochre shelf field was initially anticipated to be on line in the second quarter of 2005. Due to factors beyond our control, anticipated production from these projects is now expected to commence early in the third quarter of 2005.

Development Projects. In late 2004, we participated in a successful exploratory well in our North Black Widow prospect in Ewing Banks 921, which is located approximately 125 miles south of New Orleans in approximately 1700 feet of water. We have a 35% working interest in this project. We are in the process of development planning for the North Black Widow discovery and the operator currently anticipates production to begin in the fourth quarter of 2005. We have booked no proved reserves to this project as of December 31, 2004.

We also expect development work to be completed and production to commence at four other development projects in the second half of 2005. Mississippi Canyon 718 (Pluto), Viosca Knoll 917 (Swordfish), and Green Canyon 178 (Baccarat) are anticipated to commence production in the third quarter of 2005. Mississippi Canyon 296 (Rigel) is anticipated to commence production in the fourth quarter of 2005. Installation of facilities and equipment at Baccarat and North Black Widow are progressing as originally anticipated. However, initial production at Swordfish, Pluto and Rigel has been delayed beyond our earlier forecasts due to factors outside our control.

Production at Swordfish will be delayed approximately two months due to production facilities installation setbacks experienced by the operator of the host platform as a result of damage incurred from Hurricane Ivan. Initial production is currently expected to commence in July 2005.

At Pluto, we proceeded as scheduled to lay an extension to the existing umbilical and flowline to finalize the development operation. Once on location, adverse current conditions in the eastern Gulf of Mexico (loop currents associated with the Gulf Stream current) prevented the safe unloading and

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installation of subsea facilities at the Pluto site. We are currently scheduled to attempt a second installation in June. If the loop currents subside and we encounter no further problems, initial production should commence in July 2005.

Installation of facilities and equipment at Rigel has progressed as expected, except for the umbilical line, which has experienced manufacturing delays. The contractor was unable to deliver the umbilical in usable condition from its U.S. plant and has moved final fabrication to a plant in the United Kingdom. Earliest production is now anticipated in the fourth quarter of 2005.

Production at our Mississippi Canyon 66(Ochre) field has been shut-in since September 2004 due to destruction of the host facility during Hurricane Ivan. Recommencing production at the field has been awaiting final negotiation of an acceptable production handling agreement with the operator of a replacement host facility. We believe we are nearing a final agreement to tie in production to a nearby replacement facility and anticipate production to recommence in the third quarter of 2005. The field was producing at approximately 6.5 MMcfe per day net to our interest immediately prior to being shut-in by the hurricane.

We believe the delays we have incurred on these projects should have no adverse impact on our volumes of estimated proved reserves or estimated daily production rates when production commences.

Commodity Price Risk Management. During the first quarter of 2005, we placed additional natural gas hedges of 4,400,000 MMBtus, 3,832,500 MMBtus, and 3,504,000 MMBtus for 2005, 2006, and 2007, respectively. Costless collars were utilized with a weighted average floor of $6.02 per MMBtu and a weighted average ceiling of $8.06 per MMBtu.

Acquisitions. In February 2005, we acquired five producing wells located in Howard County, Texas, approximately 50 miles north of our Aldwell Unit. The purchase price was $3.5 million, subject to post-closing adjustments.

We currently hold a 20% working interest in the Bass Lite project and have entered into an agreement to acquire an additional 18.75% working interest for approximately $5.0 million subject to the other working interest owners waiving their preferential rights. The Bass Lite project is located in Atwater Valley approximately 200 miles southeast of New Orleans in approximately 6,500 feet of water. This property has not been included in our proved reserves because firm commitments for access to third party host facilities for production and processing are not in place. We have been elected operator of the project, subject to MMS approval, and negotiations continue with third party host facilities and partners to establish firm development plans.

Seismic Data. In April 2005, we entered into an agreement that provides us with access to a third party s recent vintage 3-D seismic database covering over 1,500 blocks on the Gulf of Mexico shelf. Over the next two years we will select and license seismic data from this database covering up to 1,000 shelf blocks. This will increase significantly the amount of seismic data for the Gulf of Mexico that Mariner has under license, which currently covers more than 5,000 blocks of the Gulf of Mexico shelf and deepwater.

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Summary of Development and Exploration Projects

The following tables summarize information regarding our 2004 and current budgeted 2005 development and exploration expenditures. The current budgeted 2005 capital expenditures are subject to change depending upon a number of factors, including availability of capital, drilling results, oil and natural gas prices, new drilling opportunities, costs of drilling and completion and availability of drilling rigs, equipment and labor.

	2004 Capital Expenditures	2005 Budgeted Capital Expenditures
Development Expenditures		
Gulf of Mexico Deepwater	$ 43.6	$ 45.1
Gulf of Mexico Shelf	24.7	15.4
West Texas Permian Basin	20.3	33.3
Total Development Capital Expenditures	$ 88.6	$ 93.8
Exploration Expenditures		
Exploratory Drilling		
Gulf of Mexico Deepwater	$ 19.9	$ 12.8
Gulf of Mexico Shelf	13.6	16.4
Leasehold Acquisition	3.5	6.5
Delay Rentals	1.3	1.5
Geological & Geophysical	9.6	8.7
Total Exploration Capital Expenditures	$ 47.9	$ 45.9
Total Development and Exploration Capital Expenditures(1)	$ 136.5	$ 139.7

(1) Excludes $7.5 million and $7.6 million for other items (primarily capitalized overhead and interest) for 2004 and 2005, respectively, and $4.9 million and $5.0 million for acquisitions of properties for 2004 and 2005, respectively. See Business Strategy and Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital Expenditures and Capital Resources.

Corporate Information

We were incorporated in August 1983 as a Delaware corporation. We have two subsidiaries, Mariner LP LLC, a Delaware limited liability company, and Mariner Energy Texas LP, a Delaware limited partnership.

On March 2, 2004, Mariner s former indirect parent, Mariner Energy LLC, merged with MEI Acquisitions Holdings, LLC, an affiliate of the private equity funds, Carlyle/ Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC. Prior to the merger, we were owned indirectly by Joint Energy Development Investments Limited Partnership (JEDI), which was an indirect wholly owned subsidiary of Enron Corp. As a result of the merger, we are no longer affiliated with Enron Corp. See Business Enron Related Matters.

In March 2005, we completed a private placement of 16,350,000 shares of our common stock to qualified institutional buyers, non-U.S. persons and accredited investors. Our former sole stockholder, MEI Acquisitions Holdings, LLC, also sold 15,102,500 shares of our common stock in the private placement. We used the net proceeds from the sale of 12,750,000 shares of our common stock to purchase and retire an equal number of shares of our common stock from our former sole stockholder. As a result, an affiliate of our former sole stockholder now beneficially owns 5.3% of our outstanding common stock. See Security Ownership of Certain Beneficial Owners and Management.

Our principal executive office is located at 2101 Citywest Blvd., Suite 1900, Houston, Texas 77042-3020, and our telephone number is (713) 954-5500.

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The Offering

Common stock offered by selling stockholders	33,348,130 shares.
Use of proceeds	We will not receive any proceeds from the sale of the shares of common stock by the selling stockholders.
Listing	We intend to apply to list our common stock on The Nasdaq Stock Market under the symbol .
Common stock split	Unless specifically indicated or the context requires otherwise, the share and per share information of this offering gives effect to a 21,556.61594 to 1 stock split, which was effected on March 3, 2005.
Dividend Policy	We do not expect to pay dividends in the near future.

Risk Factors

You should carefully consider all of the information contained in this prospectus prior to investing in the common stock. In particular, we urge you to carefully consider the information under Risk Factors, beginning on page 7 of this prospectus so that you understand the risks associated with an investment in our company and the common stock. These risks include the following:

- Oil and natural gas prices are volatile, and a decline in oil and natural gas prices would affect significantly our financial results and impede our growth.

- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will affect materially the quantities and present value of our reserves.

- Unless we replace our oil and natural gas reserves, our reserves and production will decline.

- Relatively short production periods or reserve life for Gulf of Mexico properties subject us to higher reserve replacement needs and may impair our ability to replace production during periods of low oil and natural gas prices.

RISK FACTORS

You should consider carefully each of the risks described below, together with all of the other information contained in this prospectus, before deciding to invest in our common stock.

Risks Related to Our Business

Oil and natural gas prices are volatile, and a decline in oil and natural gas prices would affect significantly our financial results and impede our growth.

Our revenues, profitability and cash flow depend substantially upon the prices and demand for oil and natural gas. The markets for these commodities are volatile and even relatively modest drops in prices can affect significantly our financial results and impede our growth. Prices for oil and natural gas fluctuate widely in response to relatively minor changes in the supply and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control, such as:

- domestic and foreign supply of oil and natural gas;
- price and quantity of foreign imports;
- actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil price and production controls;
- level of consumer product demand;
- domestic and foreign governmental regulations;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- weather conditions;
- technological advances affecting oil and natural gas consumption;
- overall U.S. and global economic conditions; and
- price and availability of alternative fuels.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 64% of our estimated proved reserves as of December 31, 2004 were natural gas reserves, our financial results are more sensitive to movements in natural gas prices. Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition and results of operations.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will affect materially the quantities and present value of our reserves.

Estimating oil and natural gas reserves is complex and inherently imprecise. It requires interpretation of the available technical data and making many assumptions about future conditions, including price and other economic conditions. In preparing our estimates we project production rates and timing of development expenditures. We also analyze the available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. This process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. If the interpretations or assumptions we use in arriving at our estimates prove to be inaccurate, the amount of oil and natural gas that we ultimately recover may differ materially from the estimated quantities and net present value of reserves shown in this prospectus. See Business Proved Reserves for information about our oil and gas reserves.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates, perhaps significantly. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. At December 31, 2004, 54% of our proved reserves were proved undeveloped.

The present value of future net revenues from our proved reserves referred to in this prospectus is not necessarily the actual current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on fixed prices and costs as of the date of the estimate. Actual future prices and costs fluctuate over time and may differ materially from those used in the present value estimate. In addition, discounted future net cash flows are estimated assuming that royalties to the MMS with respect to our affected offshore Gulf of Mexico properties will be paid or suspended for the life of the properties based upon oil and natural gas prices as of the date of the estimate. See Business Royalty Relief. Since actual future prices fluctuate over time, royalties may be required to be paid for various portions of the life of the properties and suspended for other portions of the life of the properties.

The timing of both the production and expenses from the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. In addition, the 10% discount factor that we use to calculate the net present value of future net cash flows for reporting purposes in accordance with the SEC s rules may not necessarily be the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the appropriateness of the 10% discount factor in arriving at an accurate net present value of future net cash flows.

Unless we replace our oil and natural gas reserves, our reserves and production will decline.

Our future oil and natural gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our level of production and cash flows will be affected adversely. In general, production from oil and natural gas 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 oil and natural gas 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.

Relatively short production periods or reserve life for Gulf of Mexico properties subjects us to higher reserve replacement needs and may impair our ability to replace production during periods of low oil and natural gas prices.

Due to high production rates, production of reserves from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in other producing regions. As a result, our reserve replacement needs from new prospects may be greater than those of other oil and gas companies. Also, our revenues and return on capital will depend significantly on prices prevailing during these relatively short production periods. Our need to generate revenues to fund ongoing capital commitments or repay debt may limit our ability to slow or shut in production from producing wells during periods of low prices for oil and natural gas.

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Because a significant part of the value of our production and reserves is concentrated in a small number of offshore properties, any production problems or inaccuracies in reserve estimates related to those properties could affect our business materially and adversely.

During December 2004, approximately 78% of our daily production came from five offshore fields. If mechanical problems, storms or other events curtail a substantial portion of this production in the future, our cash flow would be affected adversely. At December 31, 2004, approximately 37% of our proved reserves were located on seven offshore properties. If the actual reserves associated with any one of these properties are less than our estimated reserves, our results of operations and financial condition could be adversely affected.

A substantial portion of our exploration and production activities are located in the Gulf of Mexico. This concentration of activity makes us more vulnerable than some other industry participants to the risks associated with the Gulf of Mexico, including delays and increased costs relating to adverse weather conditions such as hurricanes, which are common in the Gulf of Mexico during certain times of the year, drilling rig and other oilfield services and compliance with environmental and other laws and regulations.

Our exploration and development activities may not be commercially successful.

Exploration activities involve numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, including hurricanes, which are common in the Gulf of Mexico during certain times of the year;
- compliance with governmental regulations;
- unavailability or high cost of drilling rigs, equipment or labor;
- reductions in oil and natural gas prices; and
- limitations in the market for oil and natural gas.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain. 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 producible economically. In addition, the use of 3-D seismic and other advanced technologies require greater predrilling expenditures than traditional drilling strategies. Because of these factors, we could incur losses as a result of exploratory drilling expenditures. Poor results from exploration activities could have a material adverse effect on our future cash flows and results of operations.

Oil and gas drilling and production involve many business and operating risks, any one of which could affect our business adversely.

Our business is subject to all of the operating risks associated with drilling for and producing oil and natural gas, 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.

Our offshore operations involve special risks that could affect our operations adversely.

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.

Exploration for oil or natural gas in the deepwater of the Gulf of Mexico generally involves greater operational and financial risks than exploration on the shelf. As of December 31, 2004, approximately 37% of our estimated proved reserves, representing 47% of our PV-10, are located in the deepwater of the Gulf of Mexico. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of technological failure and usually higher drilling costs. Our deepwater wells use subsea completion techniques with subsea trees tied back to host production facilities with flow lines. The installation of these subsea trees and flow lines requires substantial time and the use of advanced remote installation mechanics. These operations may encounter mechanical difficulties and equipment failures that could result in significant cost overruns. Furthermore, the deepwater operations generally lack the physical and oilfield service infrastructure present on the shelf. As a result, a significant amount of time may elapse between a deepwater discovery and our marketing of the associated oil or natural gas, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of infrastructure, some reserve discoveries in the deepwater may never be produced economically.

Our hedging transactions may not protect us adequately from fluctuations in oil and natural gas prices and may limit future 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 oil and natural gas prices and to achieve more predictable cash flow. These financial arrangements typically take the form of price swap contracts and costless collars. Hedging arrangements expose us to the risk of financial loss in some circumstances, including situations when the other party to the hedging contract defaults on its contract or production is less than expected. During periods of high commodity prices, hedging arrangements may limit significantly the extent to which we can realize financial gains from such higher prices. For example, in calendar year 2004, our hedging arrangements reduced the benefit we received from increases in the prices for oil and natural gas by approximately $27.6 million. Although we currently maintain an active hedging program, we may choose not to engage in hedging transactions in the future. As a result, we may be affected adversely during periods of declining oil and natural gas prices.

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We will require additional capital to fund our future activities. If we fail to obtain additional capital, we may not be able to implement fully our business plan, which could lead to a decline in reserves.

We depend on our ability to obtain financing beyond our cash flow from operations. Historically, we have financed our business plan and operations primarily with internally generated cash flow, bank borrowings, proceeds from the sale of oil and natural gas properties, entering into exploration arrangements with other parties, the issuance of debt, privately raised equity and, prior to the bankruptcy of Enron Corp. (our indirect parent company until March 2, 2004), borrowings from Enron affiliates. In the future, we will require substantial capital to fund our business plan and operations. We expect to be required to meet our needs from our excess cash flow, debt financings and additional equity offerings. Sufficient capital may not be available on acceptable terms or at all. If we cannot obtain additional capital resources, we may curtail our drilling, development and other activities or be forced to sell some of our assets on unfavorable terms.

The issuance of additional debt would require that a portion of our cash flow from operations be used for the payment of interest on our debt, thereby reducing our ability to use our cash flow to fund working capital, capital expenditures, acquisitions and general corporate requirements, which could place us at a competitive disadvantage relative to other competitors. Additionally, if revenues decrease as a result of lower oil or natural gas prices, operating difficulties or declines in reserves, our ability to obtain the capital necessary to undertake or complete future exploration and development programs and to pursue other opportunities may be limited, which could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could result in a decline in our oil and natural gas reserves.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities.

Properties we acquire may not produce as expected, may be in an unexpected condition and may subject us to increased costs and liabilities, including environmental liabilities. Although we review acquired properties prior to acquisition in a manner consistent with industry practices, such reviews are not capable of identifying all potential conditions. Generally, it is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on the higher value properties or properties with known adverse conditions and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems or permit a buyer to become sufficiently familiar with the properties to assess fully their condition, any deficiencies, and development potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

Market conditions or transportation impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions, the unavailability of satisfactory oil and natural gas transportation or the remote location of our drilling operations may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines or trucking and terminal facilities. In deepwater operations, the availability of a ready market depends on the proximity of and our ability to tie into existing production platforms owned or operated by others and the ability to negotiate commercially satisfactory arrangements with the owners or operators. We may be required to shut in natural gas wells or delay initial production for lack of a market or because of inadequacy or unavailability of natural gas pipeline or gathering system capacity. When that occurs, we are unable to realize revenue from those wells until the production can be tied to a gathering system. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil and natural gas and realization of revenues.

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The unavailability or high cost of drilling rigs, equipment, supplies or personnel could affect adversely our ability to execute on a timely basis our exploration and development plans within budget.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or affect adversely our exploration and development operations, which could have a material adverse effect on our financial condition and results of operations. An increase in drilling activity in the U.S. or the Gulf of Mexico could increase the cost and decrease the availability of necessary drilling rigs, equipment, supplies and personnel.

Competition in the oil and natural gas industry is intense, and many of our competitors have resources that are greater than ours.

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing oil and natural gas and securing equipment and trained personnel. Many of our competitors, major and large independent oil and natural gas companies, possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

Financial difficulties encountered by our farm-out partners or third-party operators could affect the exploration and development of our prospects adversely.

From time to time, we enter into farm-out agreements to fund a portion of the exploration and development costs of our prospects. Moreover, other companies operate some of the other properties in which we have an ownership interest. Liquidity and cash flow problems encountered by our partners and co-owners of our properties may lead to a delay in the pace of drilling or project development that may be detrimental to a project.

In addition, our farm-out partners and working interest owners may be unwilling or unable to pay their share of the costs of projects as they become due. In the case of a farm-out partner, we may have to obtain alternative funding in order to complete the exploration and development of the prospects subject to the farm-out agreement. In the case of a working interest owner, we may be required to pay the working interest owner s share of the project costs. We cannot assure you that we would be able to obtain the capital necessary in order to fund either of these contingencies.

We cannot control the drilling and development activities on properties we do not operate.

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.

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Compliance with environmental and other government regulations could be costly and could affect production negatively.

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

Under these laws and regulations, and also common law causes of action, we could be liable for personal injuries, property damage, oil spills, discharge of pollutants and hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with these laws and regulations or to obtain or comply with required permits may result in the suspension or termination of our operations and subject us to remedial obligations as well as administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that substantially increase our costs. We cannot predict how agencies or courts will interpret existing laws and regulations, whether additional or more stringent laws and regulations will be adopted or the effect these interpretations and adoptions may have on our business or financial condition. For example, the Oil Pollution Act of 1990 (the OPA) imposes a variety of regulations on responsible parties related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations promulgated pursuant to the OPA could have a material adverse impact on us. Further, 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 have a material adverse effect on our financial condition and results of operations. See Business Regulation for more information on our regulatory and environmental matters.

Our insurance may not protect us against our business and operating risks.

We maintain insurance for some, but not all, of the potential risks and liabilities associated with our business. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to renew our existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. Although we maintain insurance at levels we believe are appropriate and consistent with industry practice, we are not fully insured against all risks, including drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our financial condition and results of operations.

We may be affected adversely if we are unable to retain or attract key personnel and executives.

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. In addition, the use of 3-D seismic and other advanced technologies requires experienced technical personnel whom we may be unable to retain or attract.

We believe that our operations are dependent to a significant extent on the efforts of key employees, most of whom have more than 20 years of experience in the oil and gas business. The loss of the services of any of these key individuals could have a material adverse effect on us. We do not maintain any insurance against the loss of any of these individuals.

Our bank credit agreement includes a change of control provision that provides in part that an event of default will occur if Scott Josey ceases to be the Chief Executive Officer or President of Mariner or to be actively engaged in the executive management of Mariner and is not replaced with an individual of comparable qualifications within six months. Therefore, if Mr. Josey were to leave our employment and we were unable to obtain the services of another senior executive with comparable experience to replace him, our banks would have the right to declare our bank loans due and we would have to seek alternative financing.

Risks Related to our Common Stock

An active market for our common stock may not develop and the market price for shares of our common stock may be highly volatile and could be subject to wide fluctuations after this offering.

Prior to the effectiveness of the registration statement of which this prospectus forms a part, we were a private company and there was no public market for our common stock. An active market for our common stock may not develop or may not be sustained after this offering. In addition, we cannot assure you as to the liquidity of any such market that may develop or the price that our stockholders may obtain for their shares of our common stock.

Even if an active trading market develops, the market price for shares of our common stock may be highly volatile and could be subject to wide fluctuations. Some of the factors that could negatively affect our share price include:

- actual or anticipated variations in our reserve estimates and quarterly operating results;
- changes in oil and gas prices;
- changes in our funds from operations or earnings estimates;
- publication of research reports about us or the exploration and production industry;
- increases in market interest rates which may increase our cost of capital;
- changes in applicable laws or regulations, court rulings and enforcement and legal actions;
- changes in market valuations of similar companies;
- adverse market reaction to any increased indebtedness we incur in the future;
- departures of key management personnel;
- actions by our stockholders;
- speculation in the press or investment community; and
- general market and economic conditions.

We do not anticipate paying any dividends on our common stock in the foreseeable future.

We do not expect to declare or pay any cash or other dividends in the foreseeable future on our common stock. Our existing revolving credit facility restricts our ability to pay cash dividends on our common stock, and we may also enter into other credit agreements or other borrowing arrangements in the future that restrict our ability to declare or pay cash dividends on our common stock.

You may experience dilution of your ownership interests due to the future issuance of additional shares of our common stock, which could have an adverse effect on our stock price.

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present stockholders and purchasers of common stock offered hereby. We are currently authorized to issue 70 million shares of common stock and 20 million shares of preferred stock with such designations, preferences and rights as determined by our board of directors. As of the date of this prospectus, 35,615,400 shares of common stock were outstanding. This includes 2,267,270 shares of common stock that have been granted to certain employees as restricted stock pursuant to our Equity Participation Plan. In addition, we have reserved an additional 2,000,000 shares for future issuance to employees as restricted stock or stock option awards pursuant to our Stock Incentive Plan, of which options to purchase 787,360 shares have already been granted. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock in connection with the hiring of personnel, future acquisitions, future private placements of our securities for capital raising purposes, or for other business purposes. Future sales of substantial amounts of our common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

Provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

The existence of some provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock. The provisions in our certificate of incorporation and bylaws that could delay or prevent an unsolicited change in control of our company include a staggered board of directors, board authority to issue preferred stock, and advance notice provisions for director nominations or business to be considered at a stockholder meeting. In addition, Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. See Description of Capital Stock.

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USE OF PROCEEDS

We will not receive any of the proceeds from the sale of the shares of common stock offered by this prospectus. Any proceeds from the sale of the shares offered by this prospectus will be received by the selling stockholders.

CAPITALIZATION

The following table shows our cash and capitalization as of December 31, 2004, on a historical basis and as adjusted to give effect to the recent issuance and sale of 16,350,000 shares of our common stock in a private placement, the application of the net proceeds from such sale, which included the purchase and retirement of 12,750,000 shares of our common stock from our former sole stockholder, and the issuance of shares of restricted common stock pursuant to our Equity Participation Plan as described under Management Equity Participation Plan. You should refer to Selected Historical Consolidated Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and the financial statements included elsewhere in this prospectus in evaluating the material presented below.

	December 31, 2004	
	Actual	As Adjusted
	(in millions)	
Cash and cash equivalents (less restricted cash)	$ 2.5	$ 2.5
Long-term debt:		
Credit facility revolving note due March 2007	$ 105.0	$ 66.0
Promissory note to former indirect stockholder(1)	10.0	4.0
Total long-term debt	115.0	70.0
Stockholders equity(2)	133.9	178.9
Total capitalization	$ 248.9	$ 248.9

(1) For a description of the promissory note to our former indirect stockholder, see Management s Discussion and Analysis of Financial Condition and Results of Operations JEDI Term Promissory Note.

(2) Reflects the receipt of net proceeds from the sale of 3.6 million shares reduced by approximately $1.9 million of offering costs.

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DILUTION

Our net tangible book value as of March 31, 2005 was $ per share of common stock. Net tangible book value per share is determined by dividing our tangible net worth (tangible assets less total liabilities) by the 35,615,400 shares of our common stock that were outstanding on March 31, 2005. Investors who purchase our common stock in this offering may pay a price per share that exceeds the net tangible book value per share of our common stock. If you purchase our common stock from the selling stockholders identified in this prospectus, you will experience immediate dilution of $ in the net tangible book value per share of our common stock, to the extent that the sale price exceeds $ per share. The following table illustrates the per share dilution to new investors purchasing shares from the selling stockholders identified in this prospectus:

Assumed offering price per share		$
Net tangible book value per share at March 31, 2005	$	
Increase per share attributable to new investors		
Net tangible book value per share after this offering		
Dilution per share to new investors		$

The foregoing discussion and table are based upon the number of shares actually issued and outstanding as of March 31, 2005. As of March 31, 2005, we had 787,360 stock options outstanding at an exercise price of $14.00 per share, none of which were vested as of March 31, 2005. To the extent the market value of our shares is greater than $14.00 per share and any of these outstanding options are exercised, there may be further dilution to new investors.

DIVIDEND POLICY

We do not expect to pay dividends in the near future. Our credit facility contains restrictions on the payment of dividends to stockholders. See Management s Discussion and Analysis of Financial Condition and Results of Operations Credit Facility.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following table shows our historical consolidated financial data as of and for each of the five years ended December 31, 2004. You should read the following data in connection with Capitalization, Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements included elsewhere in this prospectus, where there is additional disclosure regarding that information. Our historical results are not necessarily indicative of results to be expected in future periods.

	Pre-Merger					Post-Merger	Combined(1)
	Year Ended December 31,				Period from January 1, 2004 to March 2, 2004	Period from March 3, 2004 to December 31, 2004	Year Ended December 31, 2004
	2000	2001	2002	2003			
	(in millions, except per share data)						
Statement of Operations Data:							
Total revenues	$ 121.1	$ 155.0	$ 158.2	$ 142.5	$ 39.8	$ 174.4	$ 214.2
Lease operating expenses	17.2	20.1	26.1	24.7	4.1	21.4	25.5
Transportation expenses	7.8	12.0	10.5	6.3	1.1	1.9	3.0
Depreciation, depletion and amortization	56.8	63.5	70.8	48.3	10.6	54.3	64.9
Inventory adjustment to lower of cost or market						1.0	1.0
Derivative settlement				3.2			
Impairment of Enron related receivables		29.5	3.2				
General and administrative expenses	6.5	9.3	7.7	8.1	1.1	7.6	8.8
Operating income	32.8	20.6	39.9	51.9	22.9	88.2	111.0
Interest income	0.1	0.7	0.4	0.8	0.1	0.2	0.3
Interest expense	(11.0)	(8.9)	(10.3)	(7.0)		(6.0)	(6.0)
Income before income taxes	21.9	12.4	30.0	45.7	23.0	82.4	105.3
Provision for income taxes				(9.4)	(8.1)	(28.8)	(36.9)
	21.9	12.4	30.0	36.3	14.9	53.6	68.4

Income before cumulative effect of change in accounting method net of tax effects							
Income before cumulative effect per common share							
Basic	.74	.42	1.01	1.22	.50	1.80	2.30
Diluted	.74	.42	1.01	1.22	.50	1.80	2.30
Cumulative effect of changes in accounting method				1.9			
Net income	$ 21.9	$ 12.4	$ 30.0	$ 38.2	$ 14.9	$ 53.6	$ 68.4
Net income per common share							
Basic	.74	.42	1.01	1.29	.50	1.80	2.30
Diluted	.74	.42	1.01	1.29	.50	1.80	2.30
Capital Expenditure and Disposal Data:							
Exploration, including leasehold/seismic	$ 46.7	$ 66.3	$ 40.4	$ 31.6	$ 7.5	$ 40.4	$ 47.9
Development and other	61.4	98.2	65.7	51.7	7.8	93.2	101.0
Proceeds from property conveyances	(29.0)	(90.5)	(52.3)	(121.6)			
Total capital expenditures net of proceeds from property conveyances	$ 79.1	$ 74.0	$ 53.8	$ (38.3)	$ 15.3	$ 133.6	$ 148.9

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	Pre-Merger					Post-Merger	
	Year Ended December 31,				Period from January 1, 2004 to March 2, 2004	Period from March 3, 2004 to December 31, 2004	Year Ended December 31, 2004
	2000	2001	2002	2003			
	(in millions, except per share data)						
Balance Sheet Data (at end of period):(2)							
Property and equipment, net, full cost method	$ 287.8	$ 290.6	$ 287.6	$ 207.9			$ 303.8
Total assets	335.4	363.9	360.2	312.1			376.0
Long-term debt, less current maturities	129.7	99.8	99.8				115.0
Stockholder s equity	141.9	180.1	170.1	218.2			133.9
Working capital (deficit)(3)	(15.4)	(19.6)	(24.4)	38.3			(18.7)

(1) The combined information for the year ended December 31, 2004 includes the pre-merger information for the period from January 1, 2004 to March 2, 2004 and the post-merger information for the period from March 3, 2004 to December 31, 2004.

(2) Balance sheet data as of December 31, 2004 reflects purchase accounting adjustments to oil and gas properties, total assets and stockholder s equity resulting from the acquisition of our former indirect parent on March 2, 2004.

(3) Working capital deficit excludes current derivative assets and liabilities and restricted cash.

	Pre-Merger					Post-Merger	Combined(1)
	Year Ended December 31,				Period from January 1, 2004 to March 2, 2004	Period from March 3, 2004 to December 31, 2004	Year Ended December 31, 2004
	2000	2001	2002	2003			
	(all amounts in millions)						
Other Financial Data:							
EBITDA(2)	$ 89.6	$ 84.1	$ 110.7	$ 100.3	$ 33.4	$ 143.5	$ 176.9
Net cash provided by operating activities	63.9	113.5	60.3	103.5	20.3	135.9	156.2

Capital expenditures	108.1	164.5	106.1	83.3	15.3	133.6	148.9
Reconciliation of Non-GAAP Measures:							
EBITDA	$ 89.6	$ 84.1	$ 110.7	$ 100.3	$ 33.4	$ 143.5	$ 176.9
Changes in working capital	(15.5)	7.5	(20.4)	21.8	(13.2)	6.9	(6.3)
Impairment (recovery) of Enron-related receivables		29.5	3.2				
Non-cash hedge gain(3)			(23.2)	(2.0)		(7.9)	(7.9)
Amortization/other	0.7	0.6	(0.1)			0.8	0.8
Net interest expense	(10.9)	(8.2)	(9.9)	(6.2)	0.1	(5.8)	(5.7)
Income tax expense				(10.4)		(1.6)	(1.6)
Net cash provided by operating activities	$ 63.9	$ 113.5	$ 60.3	$ 103.5	$ 20.3	$ 135.9	$ 156.2

(1) The combined information for the year ended December 31, 2004 includes the pre-merger information for the period from January 1, 2004 to March 2, 2004 and the post-merger information for the period from March 3, 2004 to December 31, 2004.

(2) EBITDA means earnings before interest, income taxes, depreciation, depletion, amortization and impairments. We believe that EBITDA is a widely accepted financial indicator that provides additional information about our ability to meet our future requirements for debt service, capital expenditures and working capital, but EBITDA should not be considered in isolation or as a substitute for net income, operating income, net cash provided by operating activities or any other measure of

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financial performance presented in accordance with generally accepted accounting principles or as a measure of a company s profitability or liquidity. Our definition of EBITDA may not be comparable to similarly titled measures of other companies.

(3) In accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 137 and No. 138, we de-designated our contracts effective December 2, 2001 after the counterparty (an affiliate of Enron Corp.) filed for bankruptcy and has recognized all market value changes subsequent to such de-designation in its earnings. The value recorded up to the time of de-designation and included in Accumulated Other Comprehensive Income (AOCI), has reversed out of AOCI and into earnings as the original corresponding production, as hedged by the contracts, is produced. We have designated subsequent hedge contracts as cash flow hedges with gains and losses resulting from the transactions recorded at market value in AOCI, as appropriate, until recognized as operating income in our Statement of Operations as the physical production hedged by the contracts is delivered.

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

Overview

On March 2, 2004, Mariner s former indirect parent, Mariner Energy LLC, merged with MEI Acquisitions Holdings, LLC, an affiliate of the private equity funds, Carlyle/ Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC. Prior to the merger, we were owned indirectly by JEDI which was an indirect wholly-owned subsidiary of Enron Corp. The gross merger consideration was $271.1 million (which excludes $7.0 million of acquisition costs and other expenses paid directly by the Company), $100 million of which was provided as equity by our new owners. As a result of the merger, we are no longer affiliated with Enron Corp. See Business Enron Related Matters. The merger did not result in a change in our strategic direction or operations. The financial information contained herein is presented in the style of Pre-Merger activity (for all periods prior to March 2, 2004) and Post-Merger activity (for the March 3, 2004 through December 31, 2004 period) to reflect the impact of the restatement of assets and liabilities to fair value as required by purchase accounting at the March 2, 2004 merger date. To facilitate management s discussion and analysis of financial condition and results of operations, we have presented 2004 financial information as Pre-Merger (for the January 1 through March 2, 2004 period), Post-Merger (for the March 3, 2004 through December 31, 2004 period), and Combined (for the full period from January 1 through December 31, 2004). We believe this provides a fair presentation of our financial performance.

In March 2005 we completed a private placement of 16,350,000 shares of our common stock to qualified institutional buyers, non-U.S. persons and accredited investors. Our former sole stockholder, MEI Acquisitions Holdings, LLC, also sold 15,102,500 shares of our common stock in the private placement. We used the net proceeds from the sale of 12,750,000 shares of our common stock to purchase and retire an equal number of shares of our common stock from our former sole stockholder. We used the remaining net proceeds of approximately $45 million to pay down outstanding debt. As a result, an affiliate of MEI Acquisitions Holdings, LLC now beneficially owns approximately 5.3% of our outstanding common stock.

We are an independent oil and natural gas exploration, development and production company with principal operations in the Gulf of Mexico and the Permian Basin in West Texas. In the Gulf of Mexico, our areas of operation include the deepwater and the shelf area. We have been active in the Gulf of Mexico and West Texas since the mid-1980s. During the last three years, as a result of increased drilling of shelf prospects and development drilling in our Aldwell Unit, we have evolved from a company with primarily a deepwater focus to one with a balance of exploitation and exploration of the Gulf of Mexico deepwater and shelf, and longer-lived Permian Basin properties.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and our ability to find, develop and acquire oil and gas reserves that are economically recoverable while controlling and reducing costs. The energy markets have historically been very volatile. Commodity prices have been at or near historical highs during 2004 and may fluctuate and decline significantly in the future. Although we attempt to mitigate the impact of price declines through our hedging strategy, a substantial or extended decline in oil and natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of natural gas and oil reserves that we can economically produce and our access to capital.

2004 Highlights

We recognized net income of $68.4 million in 2004 compared to net income of $38.2 million in 2003. The increase in net income was primarily the result of improvements in operating results, including a 13% increase in production volumes, a 21% improvement in the net commodity prices realized by us (before the effects of hedging) and an 8% decrease in lease operating expenses and transportation expenses on a per unit basis. These improvements were partially offset by an 8% increase in general and administrative expenses and a 34% increase in depreciation, depletion, and amortization expenses. Our hedging results also improved by $9.7 million to a $19.8 million loss, from a $29.5 million loss in the prior year. In addition, we recorded income tax expenses of $36.9 million in 2004 compared to $9.4 million in 2003.

We have incurred and expect to continue to incur substantial capital expenditures. However, for the three years ended December 31, 2004, our capital expenditures of $337.3 million have been below our combined cash flow from operations and proceeds from property sales. We currently have capital expenditure plans for 2005 totaling approximately $152 million. We believe that cash flows from operations, existing cash and amounts available for borrowing under our revolving credit facility will be sufficient to meet our capital requirements in the next twelve months.

During 2004, we increased our proved reserves by approximately 69 Bcfe, bringing estimated proved reserves as of December 31, 2004 to approximately 237.5 Bcfe after 2004 production of 37.6 Bcfe.

We had $2.5 million and $60.2 million in cash and cash equivalents as of December 31, 2004 and December 31, 2003, respectively.

Production

Our December 2004 total production averaged approximately 58 MMcf of natural gas per day and approximately 5,700 barrels of oil per day or total equivalents of approximately 92 MMcfe per day. Natural gas production comprised approximately 63% of total production. In September 2004, the Company incurred damage from Hurricane Ivan that affected our Mississippi Canyon 66 (Ochre) and Mississippi Canyon 357 fields. Production from Mississippi Canyon 357 was shut-in until March 2005, when necessary repairs were completed and production recommenced. As of March 31, 2005, production from Mississippi Canyon 66 (Ochre) remains shut-in. This field was producing at a net rate of approximately 6.5 MMcfe per day immediately prior to the hurricane.

Historically, a majority of our total production has been comprised of natural gas. We anticipate that our concentration in natural gas production will continue. As a result, Mariner s revenues, profitability and cash flows will be more sensitive to natural gas prices than to oil and condensate prices.

Generally, our producing properties in the Gulf of Mexico will have high initial production rates followed by steep declines. As a result, we must continually drill for and develop new oil and gas reserves to replace those being depleted by production. Substantial capital expenditures are required to find and develop these reserves. Our challenge is to find and develop reserves at economic rates and commence production of these reserves as quickly and efficiently as possible.

Three of our shelf properties, Ewing Bank 977 (Dice), West Cameron 333 (Royal Flush) and High Island 46 (Green Pepper) began producing in the first quarter of 2005.

Deepwater discoveries typically require a longer lead time to bring to productive status. Since 2001, we have made several deepwater discoveries that are currently in various stages of development. We currently anticipate commencing production in 2005 from Viosca Knoll 917 (Swordfish), Mississippi Canyon 718 (Pluto), Mississippi Canyon 296 (Rigel), Green Canyon 178 (Baccarat), and Ewing Banks 921 (North Black Widow). However, myriad uncertainties, including scheduling, weather, and construction lead times, could cause a delay in the start up of any one or all of the projects.

Oil and Gas Property Costs

During 2004, we incurred approximately $148.9 million in capital expenditures with 60% related to development activities, 32% related to exploration activities, including the acquisition of leasehold and seismic, and the remainder related to acquisitions and other items (primarily capitalized overhead and interest).

We spent approximately $88.6 million in development capital expenditures in 2004 primarily on Aldwell Unit development and for Viosca Knoll 917 (Swordfish), Mississippi Canyon 718 (Pluto), and West Cameron 333 (Royal Flush) offshore projects.

All capital for exploration activities relate to offshore projects, with approximately 30% of exploration capital expended for leasehold, seismic, and geological and geophysical costs. During 2004 we participated in fourteen exploration wells, with seven being successful. We incurred approximately $47.9 million of exploration capital expenditures in 2004.

We anticipate that, based on our current budget, capital expenditures in 2005 will approximate $152 million with approximately 62% allocated to development projects, 30% to exploration activities, 3% to acquisitions and the remainder to other items (primarily capitalized overhead and interest).

Oil and Gas Reserves

We have maintained our reserve base through exploration and exploitation activities despite selling 79.7 Bcfe of our reserves since the fourth quarter of 2001. Historically, we have not acquired significant reserves through acquisition activities. As of December 31, 2004, Ryder Scott estimated our net proved reserves at approximately 237.5 Bcfe, with a present value, discounted at 10% per annum, of pre-tax future net cash flows of approximately $668 million. See Business Proved Reserves for more information concerning our reserve estimates.

The development drilling at our West Texas Aldwell Unit and Gulf of Mexico deepwater divestitures have significantly changed our reserve profile since 2001. Proved reserves as of December 31, 2004 were comprised of 48% West Texas Permian Basin, 15% Gulf of Mexico shelf and 37% Gulf of Mexico deepwater compared to 20% West Texas Permian Basin, 15% Gulf of Mexico shelf and 65% Gulf of Mexico deepwater as of December 31, 2001. The change has resulted in a more balanced reserve base, increased average reserve life and a more predictable cost and production profile. Proved undeveloped reserves were approximately 54% of total proved reserves as of December 31, 2004. Approximately 39% of proved undeveloped reserves were related to our West Texas Aldwell Unit, where we had 100% development drilling success on 105 wells from 2002 through 2004.

Oil and Natural Gas Prices and Hedging Activities

Prices for oil and natural gas can fluctuate widely, thereby affecting the amount of cash flow available for capital expenditures, our ability to borrow and raise additional capital and the amount of oil and natural gas that we can economically produce. Recently, oil and natural gas prices have been at or near historical highs and very volatile as a result of various factors, including weather, industrial demand, war and political instability and uncertainty related to the ability of the energy industry to provide supply to meet future demand.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and our ability to find, develop and acquire oil and gas reserves that are economically recoverable while controlling and reducing costs. A substantial or extended decline in oil and natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that we can economically produce and access to capital.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and natural gas prices. Typically, our hedging strategy involves entering into commodity price swap arrangements and costless collars with third parties. Price swap arrangements establish a fixed price and an index-related price for the covered commodity. When the index-related price exceeds the fixed price, we pay the third party the difference, and when the fixed price exceeds the index-related prices, the third party pays us the difference. Costless collars establish fixed cap (maximum) and floor (minimum) prices as well as an index-related price for the covered commodity. When the index-related price exceeds the fixed cap price, we pay the third party the difference, and when the index-related price is less than the fixed floor price, the third party pays us the difference. While our hedging arrangements enable us to achieve a more predictable cash flow, these arrangements also limit the benefits of increased prices. As a result of increased oil and natural gas prices, we incurred cash hedging losses of $27.7 million in 2004, of which $7.9 million relates to the hedge liability recorded at the March 2, 2004 merger date. Major challenges related to our hedging activities include a determination of the proper production volumes to hedge and acceptable commodity price levels for each hedge transaction. Our hedging activities may also require that we post cash collateral with our counterparties from time to time to cover credit risk. We had no collateral requirements as of December 31, 2004 or March 31, 2005.

In accordance with purchase price accounting implemented at the time of the merger of our former indirect parent company on March 2, 2004, we recorded the mark-to-market liability of our hedge contracts at such date totaling $12.4 million as a liability on our balance sheet. As of December 31, 2004, the amount of our mark-to-market hedge liabilities totaled $22.4 million. See Liquidity and Capital Resources Commodity Prices and Related Hedging Activities.

Operating Costs

Lease operating expenses were $25.5 million in 2004, compared with $24.7 million in 2003. These costs fluctuated primarily due to levels of production and workover activities. In order to measure our operating performance, we also monitor lease operating and transportation expenses on a per unit of production basis. Lease operating expenses per Mcfe were $0.68 in 2004, compared to $0.74 in 2003. Transportation expenses were $3.0 million or $0.08 per Mcfe in 2004 as compared to $6.3 million or $0.19 per Mcfe in 2003. In the fourth quarter of 2004, we filed new transportation allowances with the MMS for purposes of royalty calculation. This resulted in a $3.2 million decrease in transportation expenses in 2004 compared to 2003.

General and administrative expenses were $8.8 million, or $0.23 per Mcfe, in 2004 and $8.1 million, or $0.24 per Mcfe in 2003. Our general and administrative expenses are reported net of overhead recoveries from our working interest partners, and for 2003 and 2004, we have capitalized approximately 45% of our general and administrative expenses. For the year ended December 31, 2004, approximately 44% of our general and administrative expenses (before capitalization) were comprised of salaries and wages (excluding bonus compensation) that are subject to market-related increases.

Critical Accounting Policies and Estimates

Our discussion and analysis of Mariner s financial condition and results of operations are based upon financial statements that have been prepared in accordance with GAAP in the U.S. 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. 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, which would have a significant impact on depreciation, depletion and amortization. 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.

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

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Proved Reserves

Our most significant financial estimates are based on estimates of proved natural gas and oil reserves. Estimates of proved reserves are key components of our unevaluated properties, our rate for recording depreciation, depletion and amortization and our full cost ceiling limitation. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond our control. The estimation process relies on assumptions and interpretations of available geologic, geophysical, engineering and production data, and the accuracy of reserve estimates is a function of the quality and quantity of available data. Our reserves are fully engineered on an annual basis by Ryder Scott, our independent petroleum engineers.

Compensation Expense

As a result of the adoption of SFAS Statement No. 123(R), we will record compensation expense for the fair value of restricted stock that was granted on March 11, 2005 pursuant to our Equity Participation Plan and for the fair value of subsequent grants of stock options or restricted stock made pursuant to our Stock Incentive Plan. In general, compensation expense will be determined at the date of grant based on the fair value of the stock or options granted.

We will record compensation expense of $31.7 million for the fair value of restricted stock that we granted following the closing of the private equity placement pursuant to our Equity Participation Plan. The compensation expense will be amortized over the applicable vesting periods. Future grants of stock options and restricted stock under our Stock Incentive Plan will also result in recognition of compensation expense in accordance with FASB No. 123(R). For more information concerning our Equity Participation Plan, see Management Equity Participation Plan.

Revenue Recognition

We recognize oil and gas revenue from our interests in producing wells as oil and gas from those wells is produced and sold under the entitlements method. Oil and gas volumes sold are not significantly different from our share of production.

Income Taxes

Our taxable income through 2004 has been included in a consolidated U.S. income tax return with our former indirect parent company, 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. We record 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. In February 2005, Mariner Energy LLC was merged into us, and we will file our own income tax return following the effective date of that merger.

Capitalized Interest Costs

We capitalize interest based on the cost of major development projects which are excluded from current depreciation, depletion, and amortization calculations.

Accrual for Future Abandonment Costs

SFAS No. 143, Accounting for Asset Retirement Obligations, addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 requires that the fair value of a liability for an asset s retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

Hedging Program

In June 1998 the FASB issued SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities. In June 2000 the FASB issued SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activity, an Amendment of SFAS No. 133. SFAS No. 133 and SFAS No. 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values.

The Company utilizes derivative instruments, typically in the form of natural gas and crude oil price swap agreements and costless collar arrangements, in order to manage price risk associated with future crude oil and natural gas production. These agreements are accounted for as cash flow hedges. Gains and losses resulting from these transactions are recorded at fair market value and deferred to the extent such amounts are effective. Such gains or losses are recorded in AOCI as appropriate, until recognized as operating income 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 flow 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.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with GAAP 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.

Results of Operations

For certain information with respect to our oil and natural gas production, average sales price received and expenses per unit of production for the three years ended December 31, 2004, see Business Production.

Year Ended December 31, 2004 compared to Year Ended December 31, 2003

Net production during 2004 increased to 37.6 from 33.4 Bcfe during 2003 primarily due to the commencement of production on our Roaring Fork and Ochre projects, offset by normal production declines on existing fields.

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Hedging activities in 2004 decreased our average realized natural gas price received by $0.32 per Mcf and revenues by $7.5 million, compared with a decrease of $1.03 per Mcf and revenues of $24.5 million for 2003. Our hedging activities with respect to crude oil during 2004 decreased the average sales price received by $5.35 per bbl and revenues by $12.3 million compared with a decrease of $3.11 per bbl and revenues of $5.0 million for 2003.

Oil and gas revenues increased 50% to $214.2 million during 2004 when compared to 2003 oil and gas revenues of $142.5 million, due to a 13% increase in production and a 33% increase in realized prices (including the effects of hedging) to $5.70 per Mcfe in 2004 from $4.27 per Mcfe in 2003.

Lease operating expenses increased 3% to $25.5 million in 2004 from $24.7 million in 2003 due to increased activity in our West Texas Aldwell project, partially offset by lower compression costs on our King Kong and Yosemite projects and the shut-in of our Pluto project for a large portion of 2004 pending the drilling and completion of the Mississippi Canyon 674 No. 3 well, which has been drilled and awaits installation of flowlines and related facilities.

Transportation expenses were $3.0 million for 2004, compared to $6.3 million for 2003. In the fourth quarter of 2004, we filed new transportation allowances with the MMS for purpose of royalty calculation. This resulted in a $3.2 million decrease in transportation expense in 2004 compared to 2003. In addition, transportation expense from our new Roaring Fork field was offset by declines from our existing fields.

Depreciation, depletion, and amortization expense increased 34% to $64.9 million during 2004 from $48.3 million for 2003 as a result of an increase in the unit-of-production depreciation, depletion and amortization rate to $1.73 per Mcfe from $1.45 per Mcfe for the comparable period and a production increase of 4.2 Bcfe in 2004 compared to 2003. The per unit increase is primarily attributable to non-cash purchase accounting adjustments resulting from the merger.

General and administrative expenses (G&A), which is net of $4.4 million of overhead reimbursements received from other working interest owners, increased 8% to $8.8 million during 2004 compared to $8.1 million in 2003 primarily due to increased compensation costs paid in connection with the merger and payments made pursuant to services contracts with affiliates of our sole stockholder, offset by increased overhead recoveries from our partners and amounts capitalized.

Inventory adjustments to lower of cost or market, reflects the reduction of the carrying cost of our inventory as of December 31, 2004 by $1.0 million to account for a reduction in estimated value primarily related to subsea trees held in inventory.

Net interest expense for 2004 decreased 8% to $5.7 million from $6.2 million for 2003, primarily due to the repayment of our senior subordinated notes in August 2003, replaced by lower-cost bank debt in March 2004.

Income before income taxes and change in accounting method increased to $105.3 million for 2004 compared to $45.7 million in 2003, attributable primarily to the increase in oil and gas revenues resulting from the increased production and realized prices noted above.

Provision for income taxes, increased to $36.9 million for 2004 from $9.4 million for 2003 as a result of increased current year operating income.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Net production decreased during 2003 to 33.4 Bcfe from 39.8 Bcfe in 2002. Production from new drilling in our onshore Aldwell project and offshore Roaring Fork and Vermilion 143 projects was offset by production declines in other fields and loss of production from our offshore Pluto project during the first seven months of 2003 as a result of a flowline mechanical problem that required extended maintenance.

Hedging activities in 2003 decreased our average realized natural gas price received by $1.03 per Mcf and revenues by $24.5 million, compared with an increase of $0.68 per Mcf and revenues of $20.3 million in 2002. Our hedging activities with respect to crude oil during 2003 decreased the average sales price received by $3.11 per bbl and revenues by $5.0 million compared with an increase of $1.25 per bbl and revenues of $2.1 million in 2002.

Oil and gas revenues decreased 10% to $142.5 million in 2003 from $158.2 million in 2002 (including the effects of hedge gains and losses), due to a 16% decrease in production offset by an 8% increase in average realized prices to $4.27 per Mcfe in 2003 from $3.97 per Mcfe in 2002 including the effects of hedging gains and losses.

Lease operating expenses decreased 5% to $24.7 million in 2003 from $26.1 million in 2002 due to the reduced chemical requirements at our King Kong and Yosemite projects offset by higher chemical costs at our Pluto field.

Transportation expenses decreased 40% to $6.3 million for 2003 from $10.5 million for 2002. The decrease was primarily attributable to lower minimum fees required under the transportation agreement for our Pluto project.

Depreciation, depletion, and amortization expense decreased 32% to $48.3 million for 2003 from $70.8 million for 2002 as a result of the decrease in the unit-of-production depreciation, depletion and amortization rate to $1.45 per Mcfe from $1.78 per Mcfe and 6.4 Bcfe of less production in 2003 compared to 2002. The primary driver behind the reduced DD&A rate per Mcfe was the reduction of our full cost pool and concurrent reduction of proved reserves by the proceeds from the sale of an interest in the Falcon and Harrier properties in 2003.

Early derivative settlements of non hedge designated instruments resulted in a loss of $3.2 million in 2003. There were no similar transactions in 2002.

G&A, which is net of $1.8 million of overhead reimbursements received from other working interest owners, increased 5% to $8.1 million for 2003 from $7.7 million for 2002. The increase was comprised of an 11% reduction in gross G&A (before capitalized items and overhead recoveries) driven primarily by reduced professional service costs and office rent, offset by higher employee compensation costs, which included retention payments. The reduction in gross G&A was offset by reduced overhead recoveries and capitalized items compared to 2002.

Net interest expense for 2003 decreased 37% to $6.2 million from $9.9 million for 2002, primarily due to mid-year retirement of our senior subordinated notes.

Income before income taxes and change in accounting method increased to a net income of $45.7 million for 2003 from $30.0 million in 2002, primarily as a result of 30% higher operating income (primarily driven by lower DD&A partially offset by lower oil and gas revenues) all as described more fully above.

Provision for income taxes increased to $9.4 million in 2003 as a result of the Company utilizing all of its net operating losses. The provision for income taxes in 2002 was $0.

Liquidity and Capital Resources

Cash Flows and Liquidity

As of December 31, 2004, we had negative working capital of approximately $18.7 million compared to positive working capital of $38.3 million at December 31, 2003, in each case excluding current derivative liabilities and restricted cash. The reduction in working capital from the prior year is primarily the result of a change in the manner the Company utilizes excess cash. At year-end 2003, the Company operated with no debt and consequently accumulated cash (approximately $60 million at year-end 2003) generated by operations and asset sales in order to fund future obligations and business activities. In March 2004, the Company entered into a revolving credit facility, and since then has utilized excess cash to pay down outstanding advances to maintain debt levels as low as possible. In addition, our accounts payable and accrued liabilities at December 31, 2004 increased by about 28% over levels at December 31, 2003 primarily as a result of funding for development of our deepwater projects in progress at year end.

Our 2004 capital expenditures were $148.9 million. Approximately 60% of our capital expenditures were incurred for development projects, 32% for exploration activities and the remainder for acquisitions and other items (primarily capitalized overhead and interest).

We anticipate that our capital expenditures for the year 2005 will approximate $152 million with approximately 62% allocated to development projects, 30% to exploration activities and the remainder for acquisitions and other items (primarily capitalized overhead and interest).

We believe that cash flows generated by operations for 2005 will exceed capital expenditures incurred. However, the timing of expenditures (especially regarding deepwater projects) is unpredictable, and we will likely be required to incur debt under our revolving credit facility periodically to fund capital expenditures. Also, our cash flows are heavily dependent on the oil and natural gas commodity markets and our ability to hedge oil and natural gas prices is limited by our revolving credit facility to no more than 80% of our expected production from proved developed producing reserves. If either oil or natural gas commodity prices decrease from their current levels, our ability to finance our planned capital expenditures could be affected negatively. Furthermore, amounts available for borrowing under our revolving credit facility are largely dependent on our level of proved reserves and current oil and natural gas prices. If either our proved reserves or commodity prices decrease, amounts available to us to borrow under our revolving credit facility could be negatively affected. If our cash flows are less than anticipated or amounts available for borrowing under our revolving credit facility are reduced, we may be forced to defer planned capital expenditures.

In conjunction with the March 2004 merger, we established a new credit facility maturing on March 2, 2007. The new credit facility was fully drawn at inception for $135 million. See Credit Facility. In addition, we issued a $10 million promissory note to JEDI as part of the merger consideration. See Business Enron Related Matters and JEDI Term Promissory Note. This note matures in March 2006. Net proceeds from a private equity placement were approximately $45 million, of which $6 million was used to pay down the JEDI promissory note with the remainder used to pay down the credit facility. As of March 31, 2005, we had $80 million available for reborrowing on a revolving basis under our credit facility, subject to future adjustments of our borrowing base.

We had a net cash outflow of $57.6 million in 2004, compared to a net cash inflow of $41.8 million in 2003 and a net cash inflow of $6.5 million in 2002. A discussion of the major components of cash flows for these periods follows.

	Pre-Merger			Post-Merger	Combined
	Year Ended December 31,		Period from January 1, 2004 to March 2, 2004	Period from March 3, 2004 to December 31, 2004	Year Ended December 31, 2004
	2002	2003			
	(in millions)				
Cash flows provided by operating activities	$ 60.3	$ 103.5	$ 20.3	$ 135.9	$ 156.2

Cash flows provided by operating activities in 2004 increased by $52.7 million compared to 2003 primarily due to improved operating results and net income driven by increased production volumes and higher net oil and natural gas prices realized by the Company.

Pre-Merger	Post-Merger	Combined

	Year Ended December 31, 2002	Year Ended December 31, 2003	Period from January 1, 2004 to March 2, 2004	Period from March 3, 2004 to December 31, 2004	Year Ended December 31, 2004
	(in millions)				
Cash flows used in (provided by) investing activities	$ 53.8	$ (38.3)	$ 15.3	$ 133.6	$ 148.9

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Cash flows used in investing activities in 2004 increased by $187.2 million compared to 2003 due to increased capital expenditures in 2004 and the sale of assets in prior years.

	Pre-Merger			Post-Merger	Combined
	Year Ended December 31,		Period from January 1, 2004 to March 2, 2004	Period from March 3, 2004 to December 31, 2004	Year Ended December 31, 2004
	2002	2003			
			(in millions)		
Cash flows used in financing activities		$ (100.0)		$ (64.9)	$ (64.9)

Cash flows used in financing activities in 2004 decreased by $35.1 million compared to 2003 as a result of a $166 million dividend to our former indirect parent used to help repay a term loan to an affiliate of Enron Corp. and the placement of our revolving credit facility.

Commodity Prices and Related 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 price swap agreements and costless collar arrangements. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements.

As of December 31, 2004 the Company had the following hedge contracts outstanding:

Fixed Price Swaps	Quantity	Fixed Price	December 31, 2004 Fair Value Gain/(Loss)
			(in millions)
Crude Oil (Bbls)			
January 1 December 31, 2005	606,000	$ 26.15	$ (10.0)
January 1 December 31, 2006	140,160	29.56	(1.5)
Natural Gas (MMBtus)			
January 1 December 31, 2005	8,670,159	5.41	(7.0)
January 1 December 31, 2006	1,827,547	5.53	(1.9)
Total			$ (20.4)

December 31, 2004

Costless Collars		Quantity	Floor	Cap	Fair Value Gain/(Loss)
					(in millions)
Crude Oil (Bbls)					
January 1	December 31, 2005	229,950	$ 35.60	$ 44.77	$ (0.4)
January 1	December 31, 2006	251,850	32.65	41.52	(0.7)
January 1	December 31, 2007	202,575	31.27	39.83	(0.6)
Natural Gas (MMBtus)					
January 1	December 31, 2005	2,847,000	5.73	7.80	0.4
January 1	December 31, 2006	3,514,950	5.37	7.35	(0.3)
January 1	December 31, 2007	1,806,750	5.08	6.26	(0.4)
Total					$ (2.0)

We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Under the terms of some of these transactions, from time to time we may be required to provide security in the form of cash or letters of credit to our counterparties. As of December 31, 2004, we had no deposits for collateral.

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

	Year Ended December 31,		
	2002	2003	2004
	(dollars in millions)		
Natural Gas			
Quantity settled (MMBtus)		25,520,000	18,823,063
Increase (Decrease) in Natural Gas Sales		$ (27.1)	$ (10.8)
Crude Oil			
Quantity settled (Mbbls)	353	730	1,554
Increase (Decrease) in Crude Oil Sales	$ (0.8)	$ (5.0)	$ (16.9)

In accordance with purchase price accounting implemented at the time of the merger of our former indirect parent on March 2, 2004, we recorded the mark-to-market liability of our hedge contracts at such date totaling $12.4 million as a liability on our balance sheet. See Critical Accounting Policies and Estimates Hedging Program. For the year ended December 31, 2004, $7.9 million of the $27.7 million of cash hedge losses relate to the liability recorded at the time of the merger.

Interest Rate Hedges

Borrowings under our revolving credit the facility, discussed below, mature on March 2, 2007, and bear interest at either a LIBOR-based rate or a prime-based rate, at our option, plus a specified margin. Both options expose us to risk of earnings loss due to changes in market rates. We have not entered into interest rate hedges that would mitigate such risk.

Credit Facility

We have a revolving credit facility which provides up to $150 million of revolving borrowing capacity, subject to a borrowing base limitation. The borrowing capacity is currently subject to a borrowing base of $135 million. The borrowing base is subject to redetermination by the lenders quarterly; provided however, if at least $10 million of unused availability exists, the borrowing base will be redetermined semi-annually. The borrowing base is based upon the evaluation by the lenders of our oil and gas reserves and other factors. Any increase in the borrowing base requires the consent of all lenders.

Borrowings under the facility bear interest, at our option, at a rate of (i) LIBOR plus 2.00% to 2.75% depending upon utilization, or (ii) the greater of (a) the Federal Funds Rate plus 0.50% or (b) the Reference Rate, plus 0.00% to 0.50% depending upon utilization.

Substantially all of our assets, other than the assets securing the term promissory note issued to JEDI, are pledged to secure the credit facility and obligations under hedging arrangements with members of our bank group. In addition, both of our subsidiaries, Mariner Energy Texas LP and Mariner LP LLC, have guaranteed our obligations under the credit facility. We must pay a commitment fee of 0.25% to 0.50% per year on the unused availability under the credit facility, depending upon utilization.

The credit facility contains various restrictive covenants and other usual and customary terms and conditions of a revolving credit facility, including limitations on the payment of cash dividends and other restricted payments, limitations on the incurrence of additional debt, prohibitions on the sale of assets, and requirements for hedging a portion of our oil and natural gas production. Financial covenants require us to, among other things:

- maintain a ratio, as of the last day of each fiscal quarter, of (a) current assets (excluding cash posted as collateral to secure hedging obligations) plus unused availability under the credit facility to (b) current liabilities (excluding the current portion of debt and current portion of hedge liabilities) of not less than 1.00 to 1.00;

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maintain a ratio, as of the last day of each fiscal quarter, of (a) EBITDA (earnings before interest, taxes, depreciation, amortization and depletion) to (b) the sum of interest expense and maintenance capital expenditures for such period and 20% (on an annualized basis) of outstanding advances, of not less than 1.20 to 1.00; and

maintain a ratio, as of the last day of each fiscal quarter, of (a) total debt to (b) EBITDA of not greater than 1.75 to 1.00 prior to the issuance of bonds as described in the credit agreement and 3.00 to 1.00 thereafter.

The credit facility also contains customary events of default, including the occurrence of a change of control or default by us in the payment or performance of any other indebtedness equal to or exceeding $2.0 million.

As of March 31, 2005, $55 million was outstanding under the credit facility, and the weighted average interest rate was 4.93%. This debt matures on March 2, 2007.

JEDI Term Promissory Note

As part of the merger consideration payable to JEDI, we issued a term promissory note to JEDI in the amount of $10 million. The note matures on March 2, 2006, and bears interest, payable in kind at our option, at a rate of 10% per annum until March 2, 2005, and 12% per annum thereafter unless paid in cash in which event the rate remains 10% per annum. We have chosen to pay the interest in cash rather than in kind. The JEDI note is secured by a lien on three of our properties with no proved reserves located in the Gulf of Mexico. We can offset against the note the amount of certain claims for indemnification that can be asserted against JEDI under the terms of the merger agreement. The JEDI term promissory note contains customary events of default, including an event of default triggered by the occurrence of an event of default under our credit facility. We used $6 million of the proceeds from the recent private equity placement to repay a portion of the JEDI note. As of March 31, 2005, $4 million was still outstanding under the JEDI note.

Capital Expenditures and Capital Resources

The following table presents major components of our capital expenditures for each of the three years in the period ended December 31, 2004.

	Pre-Merger			**Post-Merger**	**Combined**
	Year Ended December 31,		**Period from January 1, 2004 to March 2, 2004**	**Period from March 3, 2004 to December 31, 2004**	**Year Ended December 31, 2004**
	2002	**2003**			
	(in millions)				
Capital expenditures:					
Leasehold acquisition	$ 14.9	$ 4.8	$ 0.4	$ 4.4	$ 4.8
Oil and natural gas exploration	25.5	26.8	7.1	35.9	43.0
Oil and natural gas development	55.3	44.3	6.6	82.0	88.6
Proceeds from property conveyances	(52.3)	(121.6)			
Acquisitions				4.9	4.9
Other items (primarily capitalized overhead and interest)	10.4	7.4	1.2	6.4	7.6
	$ 53.8	$ (38.3)	$ 15.3	$ 133.6	$ 148.9

Total capital expenditures, net of proceeds from property conveyances

Our net capital expenditures for 2004 increased by $187.2 million, as compared to 2003, as a result of increased exploration and development expenditures with no offsetting proceeds from property conveyances in 2004.

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Our net capital expenditures for 2003 decreased $92.1 million as compared to 2002 as a result of higher proceeds from property conveyances and overall lower capital expenditures as result of our shift to a more balanced portfolio among Gulf of Mexico deepwater and shelf and onshore properties.

We had no long-term debt outstanding as of December 31, 2003. As of December 31, 2004, long-term debt was $115 million. See Credit Facility.

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, 2004:

	Total	Less than one year	1-3 years	3-5 years	More than 5 years
			(in millions)		
Long-term debt obligations	$ 115.0	$	$ 115.0	$	$
Operating leases	1.1	0.6	0.5		
Abandonment liabilities	24.0	4.7	7.2	7.7	4.4
Derivative liability	22.4	17.0	5.4		
Other long-term liabilities	3.0	2.0	1.0		
Total contractual cash commitments	$ 165.5	$ 24.3	$ 129.1	$ 7.7	$ 4.4

(1) As of December 31, 2004, we had incurred debt obligations under our credit facility and the JEDI promissory note that are due as follows: $10 million in 2006; and $105 million in 2007. However, we used a portion of the net proceeds of the private equity placement to repay a portion of amounts outstanding under our credit facility and $6 million under the JEDI promissory note.

MMS Appeal Mariner operates numerous properties in the Gulf of Mexico. Two of such properties were leased from the MMS subject to the Outer Continental Shelf Deep Water Royalty Relief Act (the RRA). The RRA relieved the obligation to pay royalties on certain predetermined leases until a designated volume is produced. These two leases contained language that limited royalty relief if commodity prices exceeded predetermined levels. For the years 2000, 2001, 2003 and 2004, commodity prices exceeded the predetermined levels. Management believes the MMS did not have the authority to set pricing limits, and the Company filed an administrative appeal with the MMS and has withheld royalties regarding this matter. The MMS filed a motion to dismiss our appeal with the Department of the Interior s Board of Land Appeals. On April 6, 2005, the Board of Land Appeals granted the MMS motion and dismissed our appeal. We are currently considering our alternative legal options. The Company has recorded a liability for 100% of the exposure on this matter which on December 31, 2004 was $10.9 million.

Off-Balance Sheet Arrangements

Transportation Contract In 1999, Mariner constructed a 29-mile flowline from a third party platform to the Mississippi Canyon 674 subsea well. After commissioning, MEGS LLC, an Enron affiliate, purchased the flowline from Mariner and its joint interest partner. In addition, Mariner entered into a firm transportation contract with MEGS LLC at a rate of $0.26 per MMBtu to transport Mariner s share of approximately 130,000,000 MMbtus of natural gas from the commencement of production through March 2009. Mariner s working interest in the well is 51%. For the year ended December 31, 2003, Mariner paid $1.9 million on this contract. The remaining volume commitment was 14,707,107 MMbtus or $3.8 million net to Mariner. Pursuant to the contract, the Company was required to deliver minimum quantities through the flowline or be subject to minimum monthly payment requirements.

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On May 10, 2004, Mariner and the other 49% working interest owner in the Mississippi Canyon 674 well purchased the flowline from MEGS LLC for an adjusted purchase price of approximately $3.8 million, of which approximately $1.9 million was paid by Mariner, and terminated the transportation contract and associated liability. Accordingly, we currently have no off-balance sheet arrangements.

Recent Accounting Pronouncements

On December 16, 2004, the FASB issued FASB Statement No. 123 (revised 2004), *Share-Based Payment,* (FASB No. 123(R)) that addresses the accounting for share-based payment transactions (for example, stock options and awards of restricted stock) in which an employer receives employee-services in exchange for equity securities of the company or liabilities that are based on the fair value of the company s equity securities. The new standard replaces FASB Statement No. 123, *Accounting for Stock-Based Compensation (FASB No. 123)* and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees,* and generally requires such transactions be accounted for using a fair-value-based method that recognizes compensation expense rather than the optional pro forma disclosure allowed under FASB No. 123. The Company adopted the provisions of the new standard on January 1, 2005.

On September 2, 2004, the FASB issued FASB Staff Position No. FAS 142-2, *Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil and Gas Producing Entities,* addressing whether the scope exception within SFAS No. 142, *Goodwill and Other Intangible Assets* includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing properties. The FASB staff concluded that the accounting framework for oil and gas entities is based on the level of established reserves, not whether an asset is tangible or intangible, and thus the scope exception extended to the balance sheet classification and disclosure provisions for such assets.

On September 28, 2004, the SEC released Staff Accounting Bulletin (SAB) 106 regarding the application of SFAS 143, Accounting for Asset Retirement Obligations (AROs), by oil and gas producing companies following the full cost accounting method. Pursuant to SAB 106, oil and gas producing companies that have adopted SFAS 143 should exclude the future cash outflows associated with settling AROs (ARO liabilities) from the computation of the present value of estimated future net revenues for the purposes of the full cost ceiling calculation. In addition, estimated dismantlement and abandonment costs, net of estimated salvage values, that have been capitalized (ARO assets) should be included in the amortization base for computing depreciation, depletion and amortization expense. Disclosures are required to include discussion of how a company s ceiling test and depreciation, depletion and amortization calculations are impacted by the adoption of SFAS 143. SAB 106 is effective prospectively as of the beginning of the first fiscal quarter beginning after October 4, 2004. Since our adoption of SFAS 143 on January 1, 2003, we have calculated the ceiling test and our depreciation, depletion and amortization expense in accordance with the interpretations set forth in SAB 106; therefore, the adoption SAB 106 had no effect on our financial statements.

On December 16, 2004, the FASB issued Statement 153, Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29, to clarify the accounting for nonmonetary exchanges of similar productive assets. SFAS 153 eliminates the exception from the fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. The statement will be applied prospectively and is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. We do not have any nonmonetary transactions for any period presented to which this statement would apply. We do not expect the adoption of SFAS 153 to have a material impact on our financial statements.

Quantitative and Qualitative Disclosures About Market Risk.

For a discussion of our market risk, See Liquidity and Capital Resources Commodity Prices and Related Hedging Activities.

BUSINESS

About Mariner

We are an independent oil and gas exploration, development and production company with principal operations in the Gulf of Mexico and the Permian Basin in West Texas. As of December 31, 2004, we had 237.5 Bcfe of proved reserves, of which approximately 64% were natural gas and 36% were oil and condensate. The estimated pre-tax PV10 value of our proved reserves as of December 31, 2004 was approximately $668 million. As of December 31, 2004, approximately 46% of our proved reserves were classified as proved developed. For the year ended December 31, 2004, our total net production was 37.6 Bcfe. Our proved reserve base is balanced, with 48% of the reserves located in the Permian Basin of West Texas, 37% in the Gulf of Mexico deepwater and 15% on the Gulf of Mexico shelf as of December 31, 2004.

The distribution of our proved reserves reflects our efforts over the last three years to diversify our asset base, which in prior years had been focused primarily in the Gulf of Mexico deepwater. We have shifted some of our focus on deepwater activities to increased exploration and development on the Gulf of Mexico shelf and exploitation of our West Texas Permian Basin properties. By allocating our resources among these three areas, we expect to balance the risks associated with the exploration and development of our asset base. We intend to continue to pursue moderate-risk exploratory and development drilling projects in the Gulf of Mexico deepwater and on the Gulf of Mexico shelf, and also target low-risk infill drilling projects in West Texas. It is our practice to generate most of our prospects internally, but from time to time we also acquire third-party generated prospects. We then drill to find oil and natural gas reserves, a process that we refer to as growth through the drill bit.

Our Strategy

Our goal is to create stockholder value by increasing reserves, production and cash flow through the following key strategies:

Maintain a Balanced Portfolio Approach. We believe the combination of lower-risk drilling for long-lived onshore reserves and moderate-risk exploration, exploitation and development of the Gulf of Mexico shelf and deepwater can generate attractive cash flow and rates of return at an acceptable level of risk.

Exploit Our Existing Reserve Base. Approximately 60% of our capital expenditures in 2004 were incurred for development activities. We plan to allocate approximately 62% of our estimated capital expenditures in 2005 for the same purpose. We drilled three development wells in the Gulf of Mexico during 2004 and expect to drill several development wells in 2005. We will also continue to pursue development of the necessary third-party production and processing infrastructure to allow us to begin production from previous Gulf of Mexico discoveries that are not currently included in our proved reserves.

Our proved undeveloped reserves as of December 31, 2004 include 148 locations and 50 Bcfe at our Aldwell Unit in the West Texas Permian Basin. During 2004, we drilled 54 wells at Aldwell, all of which were successful. We intend to expand our West Texas holdings by selectively acquiring additional assets to provide growth opportunities.

We believe that conversion of proved undeveloped reserves and probable reserves to proved developed reserves is a low-risk, cost-effective strategy to increase stockholder value.

Manage Exploration and Development Exposure. To better manage the risk of developing our asset base, we intend to limit our net exploration and development exposure on offshore projects. Our goal is to limit our exposure on any single project and participate in a greater number of projects, thereby employing a portfolio approach to manage our risk exposure. Generally, we prefer to limit our ownership of these projects to a working interest not exceeding 50% and to limit our estimated net exploration dry hole costs to $4 million per well in order to better diversify our project capital expenditures. In addition, with our internally generated prospects, we seek arrangements with industry partners in which they agree to pay a disproportionate share of risked dry hole costs and compensate us for expenses incurred in prospect

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generation. We intend to continue our practice of sharing costs of offshore exploration and development activities by selling interests in projects to industry partners. From time to time, we may also sell entire interests in offshore prospects in order to better diversify our portfolio, and we may enter into trades or farm-in transactions whereby we acquire interests in third-party generated prospects. We believe all of these measures allow us to participate in more projects with significant upside and limit the risks associated with these activities and to achieve better than average risk-adjusted returns.

Approximately 32% of our capital expenditures in 2004 were allocated to shelf and deepwater exploration activities in the Gulf of Mexico with a moderate risk profile. We plan to allocate approximately 30% of our estimated capital expenditures in 2005 to similar types of opportunities. Shelf wells are generally less expensive to drill and complete and can be brought on production more quickly than deepwater wells. Reserve targets for deepwater wells are typically larger. We will continue to pursue select deepwater projects that we believe have sufficient gross reserve potential to provide acceptable risk/reward ratios. To better manage the typically higher costs of deepwater projects, we generally focus on projects that can be brought online for production utilizing subsea tieback technology. This technology is a relatively low-cost and time-efficient method for connecting deepwater wells to existing production facilities. We believe we have developed considerable expertise in the application of subsea tieback technology.

Achieve Efficiency Through Operatorship. Mariner s operations professionals are experienced in all aspects of oil and gas exploration, development and production activities, from managing and directing the drilling and completion of wells, to formulating and executing plans of development and monitoring and regulating production rates to achieve optimal results. We believe operating our wells enables us to better control the timing of the development of our projects and manage our costs more efficiently. We operate all of our wells in the Aldwell Unit in West Texas and ten of our Gulf of Mexico fields, comprising approximately 66% of our proved reserve base as of December 31, 2004.

Continue Internal Prospect Generation. We intend to continue to focus on generating a substantial number of prospects using our experienced exploration staff. By generating most of our prospects internally, we believe we maintain a more consistent inventory of quality drillable prospects, thereby increasing our chances for commercial success. We are currently working on numerous exploratory prospects for future drilling and have 36 identified prospects in our inventory.

Our technical professionals average more than 20 years of experience in the exploration and production business, much of it with major oil companies, including extensive experience in the Gulf of Mexico. Currently, our team of geoscientists has access to seismic data from multiple, recent vintage 3-D seismic databases covering more than 5,000 blocks in the Gulf of Mexico. In April 2005, we entered into an agreement that provides us with access to a third party s recent vintage 3-D seismic database covering over 1,500 blocks on the Gulf of Mexico shelf. Over the next two years we expect to license seismic data from this database covering up to 1,000 shelf blocks. Seismic data is used to develop new prospects on acreage being evaluated for leasing and to develop and further refine prospects on our 283,000 net acres of leasehold interests in the Gulf of Mexico as of March 31, 2005. Our engineers have extensive experience in offshore completion and production techniques and, in particular, a successful track record in the use of subsea tieback technology to connect wells in deeper water to existing production facilities.

We intend to continue to utilize our understanding of the geology, geophysics and production technology in the Gulf of Mexico to generate prospects internally, acquire new properties in the Gulf of Mexico at federal lease sales, and grow our reserve base through the drill bit.

Selectively Acquire Assets. Although we intend to continue to emphasize internally generated growth through the drill bit, we expect to make asset acquisitions through farm-ins, direct purchases and similar methods that will be accretive to stockholder value. Our experienced management and technical professionals have myriad industry contacts to facilitate our acquisition efforts. We expect to acquire assets that have significant potential for further reserve additions through development and exploitation activities, or otherwise provide acceptable risk adjusted rates of return. Approximately 3% of our capital expenditures in 2004 were allocated to acquisitions.

Manage Commodity Price Risk. Managing oil and gas price risk is another means we use to reduce the risk of our exploration and production activities. Oil and gas price volatility can cause fluctuation in the earnings and cash flow of an exploration and production company. We attempt to mitigate this risk with an active hedging program. The volumes we hedged for 2004 represented approximately 75% of our production. As of March 31, 2005, we had hedged 15,917,159 MMBtus of natural gas and 835,950 bbls of oil for 2005. We plan to maintain an active hedging program and as new production comes on line we expect to increase our hedge position to reduce our exposure to fluctuations in oil and gas prices and achieve more stable cash flow.

Significant Properties

We own oil and gas properties, producing and non-producing, onshore in Texas and offshore in the Gulf of Mexico, primarily in federal waters. Our largest properties, based on the present value of estimated future net proved reserves as of December 31, 2004, are shown in the following table.

	Operator	Mariner Working Interest (%)	Approximate Water Depth (Feet)	Gross Producing Wells(1)	Date Production Commenced/ Expected	Proved Reserves (Bcfe)	PV10 Value (in millions)
West Texas Permian Basin:							
Aldwell Unit	Mariner	66.5(2)	Onshore	185	1949	112.7	$ 203.8
Gulf of Mexico Deepwater:							
Mississippi Canyon 296/252 (Rigel)	Dominion	22.5	5,200	0	Fourth Quarter 2005	22.4	82.9
Viosca Knoll 917/961/962 (Swordfish)	Mariner	15.0	4,700	0	Third Quarter 2005	13.4	59.3
Green Canyon 516 (Yosemite)	ENI	44.0	3,900	1	2002	15.1	66.6
Green Canyon 646 (Daniel Boone)	W&T	40.0	4,230	0	To be det d	16.4	31.4
Ewing Bank 966 (Black Widow)	Mariner	69.2	1,850	1	2000	4.9	21.4
Mississippi Canyon 718 (Pluto)	Mariner	51.0	2,830	0	1999	9.0	31.7
Green Canyon 178 (Baccarat)	W&T	40.0	1,400	0	Third Quarter 2005	4.0	14.3
Green Canyon 472/473 (King Kong)	ENI	50.0	3,850	2	2002	1.2	2.0
Gulf of Mexico Shelf:							
South Timbalier 316 (Roaring Fork)	Kerr McGee	20.0	450	2	2003	7.1	38.0

West Cameron 333 (Royal Flush)	Mariner	83.5	70	0	February 2005	4.5	20.8
Ewing Bank 977 (Dice)	W&T	40.0	720	0	January 2005	4.2	21.3
High Island 46 (Green Pepper)	Mariner	35.0	26	0	January 2005	3.7	17.7
Mississippi Canyon 66 (Ochre)	Mariner	75.0	1,150	0	2004	3.6	11.7
Brazos A-105 (Bonvillian)	Unocal	12.5	192	3	1993	2.9	10.5
Galveston 151 (Rembrandt)	Mariner	33.3	50	3	1997	2.2	7.7
Other Properties				34		10.2	26.9
Total:				231		237.5	$ 668.0

(1) Wells producing or capable of producing as of December 31, 2004.
(2) We operate the field and own working interests in individual wells ranging from approximately 33% to 84%.

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West Texas Permian Basin

Aldwell Unit. We operate and own working interests in individual wells ranging from 33% to 84% (with an average working interest of approximately 66.5%), in the 18,500-acre Aldwell Unit. The field is located in the heart of the Spraberry geologic trend southeast of Midland, Texas, and has produced oil and gas since 1949. We began our recent redevelopment of the Aldwell Unit by drilling eight wells in the fourth quarter of 2002, 43 wells in 2003, and 54 wells in 2004. As of December 31, 2004, there were a total of 185 wells producing or capable of producing in the field. Our aggregate net capital expenditures for the 2004 drilling program in the field were approximately $20.3 million, and we added 27 Bcfe of proved reserves, while producing 4.0 Bcfe. The current average reserve to production ratio for our proved reserves in this area is approximately 22 years.

During 2005, we have accelerated our development program and intend to drill approximately 60-70 wells in our Aldwell Unit. As of March 31, 2005, 17 of these new wells have been drilled in the Aldwell Unit. All of our drilling in Aldwell has resulted in commercially successful wells.

A third party currently gathers, compresses and processes our gas from the Aldwell Unit under a contract that will expire on June 1, 2005. We are constructing our own oil and gas gathering lines and compression facilities, which are expected to be completed prior to June 1, 2005, and have entered into a contract with a third party to provide processing of our natural gas. We are also negotiating a new transportation agreement for the oil produced from the Aldwell Unit. We expect these arrangements to improve the economics of production from the Aldwell Unit.

In December 2004, we acquired an approximate 45% working interest in two Permian Basin fields containing over 4,000 acres. We believe the fields contain more than twenty 80-acre infill drilling locations and that either or both may also have 40-acre infill drilling opportunities. We have commenced drilling operations in one of the fields. In February 2005 we acquired five producing wells located in Howard County, Texas, approximately 50 miles north of our Aldwell Unit. The purchase price was $3.5 million, subject to post-closing adjustments.

Gulf of Mexico Deepwater

Mississippi Canyon 296 (Rigel). Mariner generated the Rigel prospect and acquired its interest in Mississippi Canyon block 296 at a federal offshore Gulf lease sale in March 1999. Pursuant to an agreement with third parties, in September 1999 we cross-assigned leasehold interests in Mississippi Canyon blocks 208, 252 and 296 with the result that our working interest in all three blocks is now 22.5%. The project is located approximately 130 miles southeast of New Orleans, Louisiana, in water depth of approximately 5,200 feet. A successful exploration well was drilled on the prospect in 1999. In September 2003, a successful appraisal well was drilled. This project is currently under development with a single subsea well and a planned 12-mile subsea tie back to an existing subsea manifold that is connected to an existing platform. We expect production to begin in the fourth quarter of 2005.

Viosca Knoll 917/961/962 (Swordfish). Mariner generated the Swordfish prospect and entered into a farm-out agreement with BP in September 2001. We operate and own a 15% working interest in this project, which is located in the deepwater Gulf of Mexico 105 miles southeast of New Orleans, Louisiana, in a water depth of 4,700 feet. In November and December of 2001, we drilled two successful exploration wells on blocks 917 and 962. In August 2004, a successful appraisal well found additional reserves on block 961. All wells have been completed. Initial production is planned for the third quarter of 2005, following the installation of flowlines, umbilical and host platform facilities on the Neptune Spar.

Green Canyon 516 (Yosemite). Mariner generated the Yosemite prospect and acquired the prospect at a Gulf of Mexico federal lease sale in 1998. We have a 44% working interest in this project, located in approximately 3,900 feet of water, approximately 150 miles southeast of New Orleans. In 2001, we drilled an exploratory well on the prospect, and in February 2002, we commenced production via a joint King Kong/ Yosemite 16 mile subsea tieback to an existing platform.

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Green Canyon 646 (Daniel Boone). Mariner generated the Daniel Boone prospect and acquired a 100% working interest in Green Canyon Block 646 in 1998 at a Gulf of Mexico federal lease sale. The project is located 180 miles south of New Orleans in water depth of approximately 4,230 feet. We farmed out the project, retaining a 40% working interest. A successful exploratory well was drilled in November 2003. Development plans are in progress.

Ewing Bank 966 (Black Widow). Mariner generated the Black Widow prospect and acquired its interest at a federal offshore Gulf of Mexico federal lease sale in March 1997. We operate and own a 69.2% working interest in this project, which is located in the Gulf of Mexico 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.

Mississippi Canyon 718 (Pluto). Mariner initially acquired an interest in this project in 1997, two years after gas was discovered on the project. We operate the property and own a 51% working interest in the project and the 29-mile flowline that connects to a third-party production platform. We developed the field with a single subsea well which is located in the Gulf of Mexico approximately 150 miles southeast of New Orleans, Louisiana, at a water depth of 2,830 feet. The field is currently shut-in pending the installation of the extension to the existing infield flowline and umbilical. Production is planned for the third quarter of 2005.

Green Canyon 178 (Baccarat). Mariner generated the Baccarat prospect and acquired a 100% working interest in Green Canyon block 178 at a Gulf of Mexico federal offshore lease sale in July 2003. The project is located in 1,400 feet of water approximately 145 miles southwest of New Orleans, Louisiana. Subsequent to the acquisition, Mariner entered into a farmout agreement, retaining a 40% working interest in the project. A successful exploration well was drilled in May 2004. The project is under development as a subsea tieback to an existing host platform and is expected to be online in the third quarter of 2005.

Green Canyon 472/473 (King Kong). In July 2000, Mariner acquired a 50% working interest in the King Kong Gulf of Mexico project. The project is located in approximately 3,850 feet of water, approximately 150 miles southeast of New Orleans. Mariner completed the project as a joint King Kong/ Yosemite 16 mile subsea tieback to an existing platform. Production began in February 2002. Additional development drilling is planned for 2005.

Other Prospects and Activity

In late 2004, we participated in a successful exploratory well in our North Black Widow prospect in Ewing Banks 921, which is located approximately 125 miles south of New Orleans in approximately 1,700 feet of water. We have a 35% working interest in this project. We are in the process of development planning for the North Black Widow prospect and the operator of this project currently anticipates production from this project to begin in the fourth quarter of 2005. We have booked no proved reserves to this project as of December 31, 2004.

We currently hold a 20% working interest in the Bass Lite project and have entered into an agreement to acquire an additional 18.75% working interest for approximately $5.0 million subject to the other working interest owners waiving their preferential purchase rights. The Bass Lite project is located in Atwater Valley, approximately 200 miles southeast of New Orleans in approximately 6,500 feet of water. This project is not included in our proved reserves because firm commitments for access to third party host facilities for production and processing are not in place. We were elected operator of this project, subject to MMS approval, and negotiations continue with third party host facilities and partners to establish firm development plans.

Gulf of Mexico Shelf

South Timbalier 316 (Roaring Fork). Mariner entered into a farmout agreement in October 2001 to participate in the drilling of the Roaring Fork prospect. We acquired a 20% working interest in this project, which is located in the Gulf of Mexico 135 miles south of New Orleans, Louisiana, in a water depth of 450 feet. A successful exploration well was drilled on the prospect followed by two successful appraisal wells.

West Cameron 333 (Royal Flush). Mariner acquired West Cameron block 333 in the 2003 federal lease sale. The property was acquired to exploit reserves left behind by the previous operator due to lack of compression. As operator, we drilled two successful wells and set a platform in 76 feet of water in 2004. The structure is located approximately 45 miles south of Cameron, Louisiana. Production commenced in the February of 2005. The property accounted for approximately 4.5 Bcfe of proved reserves net to our interest as of December 31, 2004.

Ewing Bank 977 (Dice). Mariner generated the Dice prospect and acquired a 100% working interest at a Gulf of Mexico federal offshore lease sale in July 2003. The project is located in 720 feet of water approximately 130 miles southwest of New Orleans, Louisiana. Subsequent to the acquisition, Mariner entered into a farm-out agreement, retaining a 40% working interest in the project. A successful exploratory well was drilled in January 2004. The project was completed as a subsea tieback to an existing host platform and began production in January 2005. The property contributed approximately 4.2 Bcfe of proved reserves net to our interest as of December 31, 2004. The Dice project is currently producing at relatively low rates from a zone that appears to be compartmentalized. We expect to sidetrack the Dice well later in the year to access a better location in the producing horizon.

High Island 46 (Green Pepper). Mariner acquired its 35% working interest in High Island block 46 via farm-in from Unocal in 2004. After drilling an exploration well resulting in the discovery of 3.7 Bcfe of net proved reserves, we set a platform in 26 feet of water approximately 35 miles southwest of Cameron, Louisiana. This Mariner-operated property began producing in January 2005.

Mississippi Canyon 66 (Ochre). Mariner acquired its Ochre prospect at a Gulf of Mexico federal lease sale in March 2002. We operate and own a 75% working interest in this project, which is located in the Gulf of Mexico approximately 100 miles southeast of New Orleans, Louisiana, in a water depth of approximately 1,150 feet. In late 2002, we drilled a successful exploration well on the prospect and commenced production in the first quarter of 2004 via subsea tieback of approximately 7 miles to the Taylor Mississippi Canyon 20 platform. In September 2004, Hurricane Ivan destroyed the Taylor platform. The subsea well is currently shut-in pending final negotiation of an acceptable production handling agreement with the operator of a nearby replacement host facility. We believe we are nearing a final agreement with the operator of the replacement host facility and production is expected to re-commence by the end of the third quarter of 2005.

Brazos A-105 (Bonvillain). Mariner generated the Brazos A-105 prospect and owns a 12.5% working interest in this property. This project is located approximately 110 miles southwest of Galveston, Texas, in a water depth of approximately 192 feet. Four wells exploit a single gas reservoir.

Galveston 151 (Rembrandt). Mariner generated the Rembrandt prospect and acquired its interest at a Gulf of Mexico federal lease sale in 1995. We currently own a 33.33% working interest in and operate this project, which is located approximately 60 miles southeast of Houston, Texas, in a water depth of approximately 50 feet. Three wells produce from this property. We propose to drill two additional wells in this field during 2005.

Other Activity

In the March 2005 Central Gulf of Mexico federal lease sale, we were the high bidder on two blocks located in water depths of 85 and 635 feet, respectively. We have been awarded one of the blocks and await an MMS decision on the second block. We are currently participating in drilling operations on two offshore exploratory prospects.

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Proved Reserves

The following tables set forth certain information with respect to our proved reserves by geographic area as of December 31, 2004. Reserve volumes and values were determined under the method prescribed by the SEC which requires the application of period-end prices and costs held constant throughout the projected reserve life. The reserve information as of December 31, 2004 is based on estimates made in a reserve report prepared by Ryder Scott. A summary of Ryder Scott s report on our proved reserves as of December 31, 2004 is attached to this memorandum as Appendix A and is consistent with filings we make with federal agencies.

Proved Reserves as of December 31, 2004

	Proved Reserve Quantities			Present Value of Estimated Future Net Revenues (PV10) (millions)		
Geographic Area	**Oil (MMbbls)**	**Natural Gas (Bcf)**	**Total (Bcfe)**	**Developed**	**Undeveloped**	**Total**
West Texas Permian Basin	8.7	62.8	114.8	$ 141.1	$ 64.4	$ 205.5
Gulf of Mexico Deepwater(1)	4.5	59.8	86.7	91.1	219.6	310.7
Gulf of Mexico Shelf(2)	1.1	29.3	36.0	103.2	48.6	151.8
Total	14.3	151.9	237.5	$ 335.4	$ 332.6	$ 668.0
Proved Developed Reserves	6.3	71.4	109.4			

(1) Deepwater refers to water depths greater than 1,300 feet (the approximate depth of deepwater designation for royalty purposes by the U.S. Minerals Management Service).

(2) Shelf refers to water depths less than 1,300 feet and includes an insignificant amount of Gulf Coast onshore properties.

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 or acquisitions, the Company s reserves and production will decline. See Risk Factors and Note 10 to the financial statements included elsewhere in this prospectus for a discussion of the risks inherent in oil and natural gas estimates and for certain additional information concerning the proved reserves.

The weighted average prices of oil and natural gas at December 31, 2004 used in the proved reserve and future net revenues estimates above were calculated using NYMEX prices at December 31, 2004, of $43.45 per bbl of oil and $6.15 per MMBtu of gas, adjusted for our price differentials but excluding the effects of hedging.

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Production

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

	Year Ended December 31,		
	2002	2003	2004
Production:			
Natural Gas (Bcf)	29.6	23.8	23.8
Oil (MMbbls)	1.7	1.6	2.3
Total natural gas equivalent (Bcfe)	39.8	33.4	37.6
Average realized sales price per unit (excluding effects of hedging):			
Natural gas ($/Mcf)	$ 3.35	$ 5.43	$ 6.12
Oil ($/bbl)	21.60	26.85	38.52
Total natural gas equivalent ($/Mcfe)	3.41	5.15	6.23
Average realized sales price per unit (including effects of hedging):			
Natural gas ($/Mcf)	$ 4.03	$ 4.40	$ 5.80
Oil ($/bbl)	22.85	23.74	33.17
Total natural gas equivalent ($/Mcfe)	3.97	4.27	5.70
Expenses ($/Mcfe):			
Lease operating	$ 0.65	$ 0.74	0.68
Transportation	0.26	0.19	0.08
General and Administrative, net(1)	$ 0.19	$ 0.24	0.23
Depreciation, depletion and amortization (excluding impairments)	1.78	1.45	1.73

(1) Net of overhead reimbursements received from other working interest owners and amounts capitalized under the full cost accounting method.

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, 2003 and December 31, 2004.

	Total Productive Wells at			
	December 31, 2003		December 31, 2004	
	Gross	Net	Gross	Net
Oil	141	101.3	197	127.9
Gas	37	10.1	34	9.5
Total	178	111.4	231	137.4

Acreage

The following table sets forth certain information with respect to the developed and undeveloped acreage as of December 31, 2004.

	Developed Acres(1)		Undeveloped Acres(2)	
	Gross	**Net**	**Gross**	**Net**
West Texas	18,536	12,303	4,557	1,975
Gulf of Mexico Deepwater(3)	79,200	30,275	224,640	124,588
Gulf of Mexico Shelf(4)	144,067	38,482	135,082	90,253
Total	241,803	81,060	364,279	216,816

(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.
(3) Deepwater refers to water depths greater than 1,300 feet (the approximate depth of deepwater designated for royalty purposes by the U.S. Minerals Management Service).
(4) Shelf refers to water depths less than 1,300 feet and includes a small amount of Gulf Coast onshore properties.

Drilling Activity

Certain information with regard to our drilling activity during the years ended December 31, 2002, 2003, and 2004 is set forth below.

	Year Ended December 31,					
	2002		2003		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Producing	2	1.00	6	2.03	7	3.34
Dry	5	2.10	6	2.35	7	2.65
Total	7	3.10	12	4.38	14	5.99
Development wells:						
Producing	11	6.65	45	30.07	56	34.84
Dry					1	0.68
Total	11	6.65	45	30.07	57	35.52
Total wells:						
Producing	13	7.65	51	32.10	63	38.18
Dry	5	2.10	6	2.35	8	3.33
Total	18	9.75	57	34.45	71	41.51

We were in the process of drilling 2 gross (1.16 net) wells as of December 31, 2004.

Property Dispositions

When appropriate, we consider the sale of discoveries that are not yet producing or have recently begun producing when we believe we can obtain acceptable returns on our investment without holding the investment through depletion. Such sales enable us to maintain 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 ended December 31, 2004. However, we sold an aggregate 50% working interest in our non-producing deepwater Falcon and Harrier projects in two separate sales for $48.8 million in 2002 and $121.6 million in 2003, respectively.

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Marketing and Customers

We market substantially all of the oil and natural gas production from the properties we operate as well as the 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-based prices. The following table lists customers accounting for more than 10% of our total revenues for the year indicated.

	Percentage of Total Revenues for Year Ended December 31, 2003		
Customer	**2002**	**2003**	**2004**
Sempra		34%	*
Bridgeline Gas Distributing Company	42%	19%	27%
Trammo Petroleum Inc.		14%	9%
Conoco Phillips	14%	*	*
Duke Energy	9%	6%	*
Genesis Crude Oil LP	4%	4%	*
Chevron Texaco			18%
BP Energy			12%

* Less than 1%

Title to Properties

Substantially all of our properties currently are subject to liens securing either our credit facility and obligations under hedging arrangements with members of our bank group or the promissory note payable to JEDI. In addition, our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other typical burdens and encumbrances. We do not believe that any of these burdens or encumbrances materially interferes with the use of such properties in the operation of our business. Our properties may also be subject to obligations or duties under applicable laws, ordinances, rules, regulations and orders of governmental authorities.

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 usually 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.

Competition

We believe that our leasehold acreage, exploration, drilling and production capabilities, large 3-D seismic database and technical and operational 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 discover reserves in the future is dependent upon our ability to evaluate and select suitable properties and 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. Larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position.

Royalty Relief

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

Leases offered for bid within five years of the RRA are referred to as post-Act leases. The RRA also allows mineral interest owners the opportunity to apply for discretionary royalty relief for new production on leases acquired before the RRA was enacted (pre-Act leases) and on leases acquired after November 28, 2000 (post-2000 leases). If the MMS determines that new production under a pre-Act lease or post-2000 lease would not be economical without royalty relief, then the MMS may relieve a portion of the royalty to make the project economical.

In addition to granting discretionary royalty relief, the MMS has elected to include automatic royalty relief provisions in many post-2000 leases, even though the RRA no longer applies. For each post-2000 lease sale that has occurred to date, the MMS has specified the water depth categories and royalty suspension volumes applicable to production from leases issued in the sale.

In 2004, the MMS adopted additional royalty relief incentives for production of natural gas from reservoirs located deep under shallow waters of the Gulf of Mexico. These incentives apply to gas produced in water depths of less than 200 meters and from deep gas accumulations located at depths of greater than 15,000 feet below the shelf. Drilling of qualified wells must have started on or after March 26, 2003, and production must begin prior to January 26, 2009.

The impact of royalty relief can be significant. The normal royalty due for leases in water depths of 400 meters or less is 16.7% of production, and the normal royalty for leases in water depths greater than 400 meters is 12.5% of production. Royalty relief can substantially improve the economics of projects located in deepwater or in shallow water and involving deep gas.

Many of our leases from the MMS contain language suspending royalty relief if commodity prices exceed predetermined threshold levels for a given calendar year. As a result, royalty relief for a lease in a particular calendar year may be contingent upon average commodity prices staying below the threshold price specified for that year. In 2000, 2001, 2003 and 2004 natural gas prices exceeded the applicable price thresholds for a number of our projects, and we have been required to pay royalties for natural gas produced in those years. However, we contested the MMS authority to include price thresholds in two of our post-Act leases, Black Widow and Garden Banks 367. We believe that post-Act leases are entitled to automatic royalty relief under the RRA regardless of commodity prices. For more information concerning the contested royalty payments, see Legal Proceedings below.

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.

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Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the regulations promulgated thereunder by the Federal Energy Regulatory Commission (FERC). In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of natural gas sales by producers began with the enactment of the Natural Gas Policy Act of 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining Natural Gas Act of 1938 and Natural Gas Policy Act of 1978 price and non-price controls affecting producer sales of natural gas effective January 1, 1993. Congress could, however, re-enact price controls in the future. The FERC 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. The FERC requires interstate pipelines to provide open-access transportation on a non-discriminatory basis for all natural gas shippers. The FERC frequently reviews and modifies its regulations regarding the transportation of natural gas with the stated goal of fostering competition within all phases of the natural gas industry. In addition, with respect to production onshore or in state waters, the intra-state transportation of natural gas would be subject to state regulatory jurisdiction as well.

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.

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. Texas and Louisiana, the 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, the spacing of wells, and the plugging and abandonment of wells and removal of related production equipment. Texas and Louisiana also restrict production to the market demand for oil and natural gas and several states have indicated interests in revising applicable regulations. These regulations can limit the amount of oil and natural gas we can produce from our wells, limit the number of wells, or limit the locations at which we can conduct drilling operations. 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. Such leases require compliance with detailed MMS regulations and orders pursuant to the Outer Continental Shelf Lands Act that are subject to interpretation and change by the MMS. Among other things, we are required to obtain prior MMS approval for our exploration plans and development and production plans at each lease. MMS regulations also impose construction requirements for production facilities located on federal offshore leases, as well as detailed technical requirements for plugging and abandonment of wells, and removal of platforms and other production facilities on such leases. The MMS requires lessees to post surety bonds, or provide other acceptable financial assurances, to ensure all obligations are satisfied on federal offshore leases. The cost of these surety bonds or other financial assurances can be substantial, and there is no assurance that bonds or other financial assurances can be obtained in all cases. We are currently in compliance with all MMS financial assurance requirements. Under certain circumstances, the MMS is authorized to suspend or terminate operations on federal offshore leases. Any suspension or termination of operations on our offshore leases could have an adverse effect on our financial condition and results of operations.

In 2000, the MMS issued a final rule that governs the calculation of royalties and the valuation of crude oil produced from federal leases. That rule amended the way that the MMS values crude oil produced from federal leases for determining royalties by eliminating posted prices as a measure of value and relying instead on arm s-length sales prices and spot market prices as indicators of value. On May 5, 2004, the MMS issued a final rule that changed certain components of its valuation procedures for the calculation of royalties owed for crude oil sales. The changes include changing the valuation basis for transactions not at arm s-length from spot to NYMEX prices adjusted for locality and quality differentials, and clarifying the treatment of transactions under a joint operating agreement. We believe that the changes will not have a material impact on our financial condition, liquidity or results of operations.

Environmental Regulations

Our operations are subject to numerous stringent and complex laws and regulations at the federal, state and local levels governing the discharge of materials into the environment or otherwise relating to human health and environmental protection. These laws and regulations may, among other things:

- require acquisition of a permit before drilling commences;
- restrict the types, quantities and concentrations of various materials that can be released into the environment in connection with drilling and production activities; and
- limit or prohibit construction or drilling activities in certain ecologically sensitive and other protected areas.

Failure to comply with these laws and regulations or to obtain or comply with permits may result in the assessment of administrative, civil and criminal penalties, imposition of remedial requirements and the imposition of injunctions to force future compliance. Offshore drilling in some areas has been opposed by environmental groups and, in some areas, has been restricted. Our business and prospects could be adversely affected to the extent laws are enacted or other governmental action is taken that prohibits or restricts our exploration and production activities or imposes environmental protection requirements that result in increased costs to us or the oil and natural gas industry in general.

Spills and Releases. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as Superfund , and analogous state laws, impose joint and several 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 and operator of the site where the release occurred, past owners and operators of the site, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Responsible parties under CERCLA may be liable for the costs of cleaning up hazardous substances that have been released into the environment and for damages to natural resources. Additionally, it is not uncommon for neighboring landowners and other third parties to file tort claims for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. In the course of our ordinary operations, we may generate waste that may fall within CERCLA s definition of a hazardous substance.

We currently own, lease or operate, and have in the past owned, leased or operated, numerous properties that for many years have been used for the exploration and production of oil and gas. 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. It is possible that hydrocarbons or other wastes may have been disposed of or released on or under such properties, or on or under other locations where such wastes may have been taken for disposal. 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, or to pay the costs of such remedial measures. Although we believe we have utilized operating and disposal practices that are standard in the industry, during the course of operations hydrocarbons and other wastes have been released on some of the properties we own, lease or operate. We are not presently aware of any pending clean-up obligations that could have a material impact on our operations or financial condition.

The Oil Pollution Act. The OPA and regulations thereunder impose strict, joint and several liability on responsible parties for damages, including natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the U.S. 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 establishes a liability limit for onshore facilities of $350 million, while the liability limit for offshore facilities is equal to all removal costs plus up to $75 million in other damages. These liability limits may not apply if a spill is caused by a party s gross negligence or willful misconduct, the spill resulted from violation of a federal safety, construction or operating regulation, or if a party fails to report a spill or to cooperate fully in a clean-up.

The OPA also requires the lessee or permittee of an offshore area in which a covered offshore facility is located to provide financial assurance in the amount of $35 million to cover liabilities related to an oil spill. The amount of financial assurance required under the OPA may be increased up to $150 million depending on the risk represented by the quantity or quality of oil that is handled by a facility. The failure to comply with the OPA s requirements may subject a responsible party to civil, criminal, or administrative 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 assurance and other operating requirements will not have a material impact on our operations or financial condition.

Water Discharges. The Federal Water Pollution Control Act of 1972, (the Clean Water Act), imposes restrictions and controls on the discharge of produced waters and other oil and gas pollutants into navigable waters. These controls have become more stringent over the years, and it is possible that additional restrictions may 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 (NPDES) 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 of oil and other pollutants, 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 pollutants, into state waters.

In furtherance of the Clean Water Act, the EPA promulgated the Spill Prevention, Control, and Countermeasure, or SPCC, regulations, which require facilities that possess certain threshold quantities of oil that could impact navigable waters or adjoining shorelines to prepare SPCC plans and meet specified construction and operating standards. The SPCC regulations were revised in 2002 and required the amendment of SPCC plans before February 18, 2006, if necessary, and requires compliance with the implementation of such amended plans by August 18, 2006. We may be required to prepare SPCC plans for some of our facilities where a spill or release of oil could reach or impact jurisdictional waters of the U.S.

Air Emissions. The Federal Clean Air Act, and associated state laws and regulations, restrict the emission of air pollutants from many sources, including oil and natural gas operations. New facilities may be required to obtain permits before operations can commence, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations. We believe that compliance with the Clean Air Act and analogous state laws and regulations will not have a material impact on our operations or financial condition.

Waste Handling. The Resource Conservation and Recovery Act (RCRA) and analogous state and local laws and regulations govern the management of wastes, including 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. RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil and natural gas. 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. However, these wastes may be regulated by EPA or state agencies as solid waste. In addition, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils, may be regulated under RCRA as hazardous waste. We do not believe the current costs of managing our wastes, as they are presently classified, to be significant. However, any repeal or modification of the oil and natural gas exploration and production exemption, or modifications of similar exemptions in analogous state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Employees

As of December 31, 2004, we had 53 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.

Legal Proceedings

Mariner operates numerous properties in the Gulf of Mexico. Two of these properties were leased from the MMS subject to the RRA. The RRA relieved the obligation to pay royalties on certain predetermined leases until a designated volume is produced. These two leases contained language that limited royalty relief if commodity prices exceeded predetermined levels. In 2000, 2001, 2003 and 2004 commodity prices exceeded the predetermined levels. Management believes the MMS did not have the authority to set pricing limits and we filed an administrative appeal contesting the MMS order and have withheld royalties regarding this matter. The MMS filed a motion to dismiss our appeal with the Board of Land Appeals of the Department of the Interior. On April 6, 2005, the Board of Land Appeals granted MMS motion and dismissed our appeal. We are currently reviewing our legal options. The Company has recorded a liability for 100% of the potential exposure on this matter, which on December 31, 2004 was $10.9 million.

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.

Insurance Matters

In September 2004, the Company incurred damage from Hurricane Ivan that affected its Mississippi Canyon 66 (Ochre) and Mississippi Canyon 357 fields. Production from Mississippi Canyon 357 was shut-in until March 2005, when necessary repairs were completed and production recommenced. Production from Ochre is currently shut-in awaiting rerouting of umbilical and flow lines to another host platform. Prior to Hurricane Ivan, this field was producing at a net rate of approximately 6.5 MMcfe per day. Production from Ochre is expected to recommence by the end of the third quarter of 2005. In addition, a semi-submersible rig on location at the Company s Viosca Knoll 917 (Swordfish) field was blown off location by the hurricane and incurred damage. Until we are able to complete all the repair work and submit costs to the insurance underwriters for review, the full extent of our insurance recovery and the resulting net cost to the Company is unknown. We expect the net cost to the Company to be at least equal to the amount of our annual deductible of $1.25 million plus the single occurrence deductible of $.375 million.

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Enron Related Matters

On March 2, 2004, our former indirect parent company, Mariner Energy LLC, merged with an affiliate of the private equity funds Carlyle/ Riverstone Global Energy and Power Fund II, L.P. and Acon Investments LLC. Prior to the merger, JEDI, which was an indirect wholly-owned subsidiary of Enron Corp., owned 96% of the common stock of Mariner Energy LLC. In the merger, all the shares of common stock in Mariner Energy LLC were converted into the right to receive cash and certain other consideration. As a result, since March 2004, JEDI no longer owns any direct or indirect interest in Mariner and we are no longer affiliated with JEDI or Enron Corp. Also in connection with the merger, warrants to purchase common stock of Mariner Energy LLC that were held by another Enron Corp. affiliate were exercised and the holders received their pro rata portion of the merger consideration, and a term loan owed by Mariner Energy LLC to the same Enron Corp. affiliate was repaid in full.

Enron Corp. and certain of its subsidiaries are currently debtors in Chapter 11 bankruptcy proceedings pending in the United States Bankruptcy Court for the Southern District of New York. Prior to the merger, we filed two proofs of claim in the Enron Corp. bankruptcy proceedings. These claims, aggregating $10.7 million, were for unpaid amounts owed to us by Enron Corp. subsidiaries under the terms of various physical commodity contracts and hedging contracts entered into prior to the Enron Corp. bankruptcy filing. We assigned these claims to JEDI as part of the merger consideration payable to JEDI under the terms of the merger agreement. Thus, as of this date, we have no claims pending in the Enron Corp. bankruptcy proceedings.

As part of the merger consideration payable to JEDI, we also issued a term promissory note to JEDI in the amount of $10 million. The note matures on March 2, 2006, and bears interest, paid in kind, at a rate of 10% per annum until March 2, 2005, and 12% per annum thereafter unless paid in cash in which event the rate remains at 10% per annum. The JEDI promissory note is secured by a lien on three of our properties located in the Outer Continental Shelf of the Gulf of Mexico. We can offset against the note the amount of certain claims for indemnification that can be asserted against JEDI under the terms of the merger agreement. We used a portion of proceeds from the common stock we sold in the private equity placement to repay $6 million of the JEDI Note.

Under the merger agreement, JEDI and the other former stockholders of our parent company were entitled to receive on or before February 28, 2005, additional contingent merger consideration based upon the results of a five-well drilling program. In September 2004, we prepaid, with a 10% prepayment discount, approximately $161,000 as the additional contingent merger consideration due with respect to the program.

Prior to the closing of the merger, we may have been within the Enron Corp. controlled group of corporations as defined under the Employee Retirement Income Security Act of 1974, as amended (ERISA) and its related regulations due to Enron Corp. s indirect ownership and/or control over Mariner. As a member of such controlled group of corporations , we may have had potential liability for certain employee benefit plan obligations of Enron Corp. However, the order of the United States Bankruptcy Court for the Southern District of New York that approved the merger states that upon consummation of the merger, our former indirect parent company, Mariner Energy LLC, as the surviving corporation in the merger, would have good title to the interests in its subsidiaries (including Mariner) and their assets free and clear of all claims and encumbrances, and rights of setoff, deduction, netting and recoupment asserted by the Pension Benefit Guaranty Corporation. Furthermore, pursuant to merger agreement, Enron Corp. has agreed to indemnify us from any liabilities imposed against us or any of our assets arising as a result of Mariner being considered an ERISA affiliate of Enron Corp. or relating to any group health insurance plans sponsored or maintained by Enron Corp. or any of its affiliates under Section 4980B of the Internal Revenue Code. Any indemnification claim against Enron Corp. arising under the merger agreement would be treated as an administrative claim in the Enron bankruptcy proceeding and entitled to priority as such. We believe that we have no remaining Enron Corp. control group liability.

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MANAGEMENT

Executive Officers and Directors

Set forth below are the names, ages and positions of our executive officers and directors as of the date of this prospectus. 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 Company
Scott D. Josey	47	Chairman of the Board, Chief Executive Officer and President
Dalton F. Polasek	53	Chief Operating Officer
Rick G. Lester	53	Vice President, Chief Financial Officer and Treasurer
Jesus G. Melendrez	46	Vice President Corporate Development
Mike C. van den Bold	43	Vice President and Chief Exploration Officer
Teresa G. Bushman	55	Vice President, General Counsel and Secretary
Judd A. Hansen	49	Vice President Shelf and Onshore
Cory L. Loegering	49	Vice President Deepwater
Bernard Aronson	58	Director
Jonathan Ginns	40	Director
Pierre F. Lapeyre, Jr.	42	Director
David M. Leuschen	54	Director

Scott D. Josey Mr. Josey has served as Chairman of the Board since August 2001. Mr. Josey was appointed Chief Executive Officer in October 2002 and President in February 2005. From 2000 to 2001, Mr. Josey served as Vice President of Enron North America Corp. and co-managed its Energy Capital Resources group. From 1995 to 2000, Mr. Josey provided investment banking services to the oil and gas industry and portfolio management services. 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 worked in all phases of drilling, production, pipeline, corporate planning and commercial activities at Texas Oil and Gas Corp. Mr. Josey is a member of the Society of Petroleum Engineers and the Independent Producers Association of America.

Dalton F. Polasek Mr. Polasek was appointed Chief Operating Officer in February 2005. From April 2004 to February 2005, Mr. Polasek served as Executive Vice President Operations and Exploration. From October 2001 to April 2004, Mr. Polasek served as Senior Vice President Operations. Prior to joining Mariner, Mr. Polasek served as: Vice President of Gulf Coast Engineering for Basin Exploration, Inc. from 1996 until February 2001; Vice President of Engineering for SMR Energy from 1994 to 1996; director of Gulf Coast Acquisitions and Engineering for General Atlantic Resources, Inc. from 1991 to 1994; and manager of planning and business development for Mark Producing Company from 1983 to 1991. He began his career in 1975 as a reservoir engineer for Amoco Production Company. Mr. Polasek is a Registered Professional Engineer in Texas and a member of the Independent Producers Association of America, the American Association of Drilling Engineers and the American Petroleum Institute.

Rick G. Lester Mr. Lester joined Mariner as Vice President, Chief Financial Officer and Treasurer in October 2004. From 1998 to 2003, Mr. Lester was the Executive Vice President, CFO and Treasurer of Contour Energy Company (which filed for Chapter 11 bankruptcy protection in July 2002 and emerged from bankruptcy in December 2002). From 1991 to 1998, Mr. Lester held the positions of Vice President, CFO and Treasurer for Domain Energy Corporation and its Tenneco Ventures predecessor. Prior to 1991, he held various positions with Tenneco, Inc. and Tenneco Exploration and Production including Corporate Finance Manager, International Tax Manager and Business Division Accounting Manager. Mr. Lester has over 30 years of industry experience and is a Certified Public Accountant.

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Jesus G. Melendrez Mr. Melendrez has served as Vice President Corporate Development since July 2003. Mr. Melendrez also served as a director of Mariner from April 2000 to July 2003. From February 2000 until July 2003, Mr. Melendrez was a Vice President of Enron North America Corp. in the Energy Capital Resources group where he managed the group s portfolio of oil and gas investments. He was a Senior Vice President of Trading and Structured Finance with TXU Energy Services from 1997 to 2000, and from 1992 to 1997, Mr. Melendrez was employed by Enron in various commercial positions in the areas of domestic oil and gas financing and international project development. From 1980 to 1992, Mr. Melendrez was employed by Exxon in various reservoir engineering and planning positions.

Mike C. van den Bold Mr. van den Bold was appointed Vice President and Chief Exploration Officer in April 2004. From October 2001 to April 2004, he served as Vice President Exploration. Mr. van den Bold joined Mariner in July 2000 as Senior Development Geologist. From 1996 to 2000, Mr. van den Bold worked for British-Borneo. He began his career at British Petroleum. Mr. van den Bold has over 17 years of industry experience. He is a Certified Petroleum Geologist, Texas Board Certified Geologist and member of the American Association of Petroleum Geologists.

Teresa G. Bushman Ms. Bushman joined Mariner as Vice President, General Counsel and Secretary in June 2003. From 1996 until joining Mariner in 2003, Ms. Bushman was employed by Enron North America Corp., most recently as Assistant General Counsel representing the Energy Capital Resources group, which provided debt and equity financing to the oil and gas industry. Prior to joining Enron, Ms. Bushman was a partner with Jackson Walker, LLP, in Houston.

Judd A. Hansen Mr. Hansen has served as Vice President Shelf and Onshore since February 2002. From 1997 until February 2001, Mr. Hansen was employed as Operations Manager of the Gulf Coast Division for Basin Exploration, Inc. From 1991 to 1997, he was employed in various engineering positions at Greenhill Petroleum Corporation, including Senior Production Engineer and Workover/Completion Superintendent. Mr. Hansen started his career with Shell Oil Company in 1978 and has 26 years of experience in conducting operations in the oil and gas industry.

Cory L. Loegering Mr. Loegering has served as Vice President Deepwater since August 2002. Mr. Loegering joined Mariner in July 1990 and since 1998 has held various positions including Vice President of Petroleum Engineering and Director of Deepwater development. Mr. Loegering was employed by Tenneco from 1982 to 1989, in various positions including as senior engineer in the economic, planning and analysis group in Tenneco s corporate offices. Mr. Loegering began his career with Conoco in 1977 and held positions in the construction, production and reservoir departments responsible for Gulf of Mexico production and development.

Bernard Aronson Mr. Aronson was elected as a director in March 2004. He is a founding partner of ACON Investments, a private equity fund. Prior to founding ACON Investments in 1996, Mr. Aronson was International Advisor to Goldman Sachs & Co. for Latin America from 1994 to 1996. From 1989 through 1993, Mr. Aronson served as Assistant Secretary of State for Inter-American Affairs. He is a member of the Council on Foreign Relations and the President s Advisory Commission on Trade Promotions and Negotiations. Mr. Aronson currently serves on the boards of directors of Liz Claiborne, Inc., Royal Caribbean International Inc., Tropigas S.A. and Hyatt International Corp.

Jonathan Ginns Mr. Ginns was elected as a director in March 2004. He is a founding partner of ACON Investments. Prior to founding ACON Investments in 1996, Mr. Ginns served as a Senior Investment Officer for the Global Environment-Emerging Markets Fund, part of the GEF Funds group, from 1994 to 1995. Mr. Ginns currently serves on the boards of directors of The Optimal Group, Signal International, Tropigas S.A. and The Commonwealth Broadcasting Corporation.

Pierre F. Lapeyre, Jr. Mr. Lapeyre was elected as a director in March 2004. He is a Founder and Managing Director of Riverstone Holdings, LLC, a private equity fund, and serves on its Managing Committee responsible for all portfolio activities. Prior to founding Riverstone in May 2000, Mr. Lapeyre served as a Managing Director of Goldman Sachs in its Global Energy and Power Group since 1996. Mr. Lapeyre joined Goldman Sachs in 1986 and spent his 14-year investment banking career focused on

the energy and power sectors. Mr. Lapeyre currently serves on the boards of directors of Legend Natural Gas II, LP, SemGroup L.P., Seabulk International, Inc., CDM Resource Management, Ltd., Frontier Holdings, Ltd, Belden & Blake Corporation, Stallion Oilfield Services, Capital C Energy, LLC and Topaz Power Group, LLC.

David M. Leuschen Mr. Leuschen was elected as a director in March 2004. He is a Founder and Managing Director of Riverstone Holdings, LLC and serves on its Managing Committee responsible for all portfolio activities. Prior to founding Riverstone May 2000, Mr. Leuschen spent 22 years with Goldman Sachs. He joined the firm in 1977, established their Global Energy and Power Group in 1982, became a Partner in 1986, and remained a Partner with the firm until leaving to found Riverstone in 2000. Mr. Leuschen currently serves as a Director of Seabulk International Inc., Frontier Holdings, Ltd, Legend Natural Gas II, LP, Belden & Blake Corporation, Buckeye GP, LLC, the general partner of Buckeye Partners, L.P., Petroplus International N.V. and Mega Energy LLC as well as a number of other industry-related businesses and nonprofit boards of directors. He is also owner and President of Switchback Ranch LLC, an integrated cattle ranching operation in the western U.S.

Messrs. Aronson, Ginns, Lapeyre and Leuschen, all of whom serve on the board of managers of our former sole stockholder, MEI Acquisitions Holdings, LLC, were elected to the board of directors in connection with the merger in March 2004 pursuant to which MEI Acquisitions Holdings, LLC became our sole stockholder. Since that time, MEI Acquisitions Holdings, LLC has sold approximately 94.7% of the shares it acquired in the merger. See Security Ownership of Certain Beneficial Owners and Management.

Board of Directors

Our board of directors currently consists of five directors. The board of directors is engaged in an active search to expand the board of directors by electing four new directors meeting independence criteria under SEC rules and under the corporate governance rules of the Nasdaq. Messrs Lapeyre and Leuschen have indicated their intention to resign, and upon their resignation, the first two new independent directors elected by the board of directors will fill their vacancies.

We have agreed that Friedman, Billings, Ramsey & Co., Inc. (FBR) may propose individuals to us and MEI Acquisitions Holdings, LLC for consideration for nomination to serve as an independent director. If any individual proposed by FBR is not selected for nomination, we may propose an individual for nomination, and FBR shall have the right to consent to one individual so nominated, provided that FBR s consent shall not be unreasonably withheld.

Our certificate of incorporation and bylaws provide for a classified board of directors consisting of three classes of directors, each serving staggered three-year terms. As a result, stockholders will elect a portion of our board of directors each year. Class I directors terms will expire at the annual meeting of stockholders to be held in 2006, Class II directors terms will expire at the annual meeting of stockholders to be held in 2007 and Class III directors terms will expire at the annual meeting of stockholders to be held in 2008. Currently, the Class I director is Mr. Aronson, the Class II directors are Messrs. Lapeyre and Leuschen, and the Class III directors are Messrs. Ginns and Josey. At each annual meeting of stockholders held after the initial classification, the successors to directors whose terms will then expire will be elected to serve from the time of election until the third annual meeting following election. The division of our board of directors into three classes with staggered terms may delay or prevent a change of our management or a change in control. See Description of Capital Stock Anti-Takeover Effects of Provisions of Delaware Law, Our Certificate of Incorporation and Bylaws Amendments to our Certificate of Incorporation and Bylaws.

In addition, our bylaws provide that the authorized number of directors, which shall constitute the whole board of directors, may be changed by resolution duly adopted by the board of directors. Any additional directorships resulting from an increase in the number of directors will be distributed among the three classes so that, as nearly as possible, each class will consist of one-third of the total number of directors. Vacancies and newly created directorships may be filled by the affirmative vote of a majority of our directors then in office, even if less than a quorum.

Committees of the Board

Our board of directors currently consists of five persons, but we expect to expand our board to seven directors, including four additional independent directors, during the year following this offering. The board of directors intends to establish three committees, the audit committee, the compensation committee and the nominating and corporate governance committee. Although we are not required to have separate compensation and nominating and corporate governance committees, we have determined that it is in the best interests of the Company to maintain independent compensation and nominating and corporate governance committees.

will be the initial member of our audit committee. He is independent under the listing standards of National Association of Securities Dealers, Inc. and SEC rules. In addition, the board of directors has determined that he is an audit committee financial expert, as defined under the rules of the SEC. Within 90 days of the effectiveness of the registration statement of which this prospectus is a part, we will expand our board of directors to include an additional independent director who will serve on the audit committee, and, within one year of the effectiveness of the registration statement, we will expand our board of directors by one more independent director who will also serve on the audit committee. The audit committee will recommend to the board of directors the independent public accountants to audit our financial statements and will oversee the annual audit. The committee will also approve any other services provided by public accounting firms. The audit committee will provide assistance to the board of directors in fulfilling its oversight responsibility to the stockholders, the investment community and others relating to the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent auditor s qualifications and independence and the performance of our internal audit function. The committee will oversee our system of disclosure controls and procedures and system of internal controls regarding financial, accounting, legal compliance and ethics that management and the board of directors have established. In doing so, it will be the responsibility of the committee to maintain free and open communication between the committee and our independent auditors, the internal accounting function and management of the Company.

will serve on the nominating and corporate governance committee of our board of directors. This committee will nominate candidates to serve on our board of directors and approves director compensation. The committee will also be responsible for monitoring a process to assess board effectiveness, developing and implementing our corporate governance guidelines and in taking a leadership role in shaping the corporate governance of the Company.

will serve on the compensation committee of our board of directors. The compensation committee will review the compensation and benefits of our executive officers, establish and review general policies related to our compensation and benefits and administers our Equity Participation Plan and Stock Incentive Plan. Under the compensation committee charter, the compensation committee will determine the compensation of our CEO.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serves as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of our board of directors or compensation committee.

During the fiscal year 2004, the board of directors determined executive compensation.

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Director Compensation

We currently do not pay director fees to our directors. We expect in the future to establish and pay directors fees for board and committee participation at a level consistent with those of similar companies, especially as we add independent directors.

Indemnification

We maintain directors and officers liability insurance. Our certificate of incorporation and bylaws include provisions limiting the liability of directors and officers and indemnifying them under certain circumstances, as described under Description of Capital Stock Liability and Indemnification of Officers and Directors. We have also entered into indemnification agreements with our executive officers and directors providing our executive officers and directors with additional assurances in a manner consistent with Delaware law.

Executive Compensation

The following table shows the annual compensation for our chief executive officer, the four other most highly compensated executive officers and one former executive officer, for the three fiscal years ended December 31, 2004.

Summary Compensation Table

Name and Principal Position	Year	Salary	Bonuses	All Other Compensation (1)
Scott D. Josey	2004	$ 350,000	$ 550,000	$ 590,133
Chairman of the Board, Chief	2003	300,290	850,000	514,895
Executive Officer and President	2002	90,909	281,250	221,439
Mike C. van den Bold	2004	192,500	215,000	336,949
Vice President and Chief	2003	170,150	350,000	45,430
Exploration Officer	2002	154,788	46,000	30,932
Dalton F. Polasek	2004	215,000	300,000	263,636
Chief Operating Officer	2003	176,698	325,000	280,677
	2002		173,438	230,568
Michael A. Wichterich(2)	2004	132,307		279,349
Former Vice President, Chief	2003	170,120	250,000	45,412
Financial Officer and Treasurer	2002	155,330	46,000	31,125
Judd A. Hansen	2004	180,000	185,000	199,059
Vice President Shelf and Onshore	2003	156,023	250,000	191,189
	2002		116,250	226,674
Teresa G. Bushman	2004	190,000	215,000	74,634
Vice President, General Counsel	2003	97,750	200,000	23,270
and Secretary	2002			

(1) Amounts shown reflect insurance premiums paid by us with respect to term life insurance for the benefit of the named executive officers and retention payments paid during the year. For Mr. Josey, the amounts shown also include amounts payable to Enron North America Corp. under a Corporate Services Agreement. In 2002 Mr. Josey became an employee of Mariner and subsequently the Corporate Services Agreement was terminated. The amounts for 2004 for Messrs. Josey, van den Bold, Polasek, Wichterich and Hansen include $6,500 of employer matching contributions made pursuant to our 401(k) plan and $8,200 made pursuant to the profit sharing portion of our 401(k) plan. In addition, the 2004 amount for Mr. Josey includes $575,000 paid with respect to Mariner s Long-Term Incentive Plan and $433 of insurance premiums under our group term life insurance. The 2004 amount for Mr. van den Bold also includes $322,000 paid with respect to Mariner s

Long-Term Incentive Plan and $249 of insurance premiums under our group term life insurance. The 2004 amount for Mr. Polasek also includes $248,400 paid with respect to Mariner s Long-Term Incentive Plan and $536 of insurance premiums under our group term life insurance. The 2004 amount for Mr. Wichterich also includes $264,500 paid with respect to Mariner s Long-Term Incentive Plan and $149 of insurance premiums under our group term life insurance. The 2004 amount for Mr. Hansen also includes $184,000 paid with respect to Mariner s Long-Term Incentive Plan and $359 of insurance premiums under our group term life insurance. The 2004 amount for Ms. Bushman includes $5,573 of employer matching contributions made pursuant to our 401(k) plan, $8,200 made pursuant to the profit sharing portion of our 401(k) plan, $59,800 paid with respect to Mariner s Long-Term Incentive Plan and $1,061 of insurance premiums under our group term life insurance.

(2) Mr. Wichterich resigned as an officer of Mariner October 8, 2004. Amounts shown for 2004 include payments made to Mr. Wichterich for his work as a part-time employee.

Employment Agreements and Other Arrangements

We have entered into an employment agreement with each of the current executive officers named in the above compensation table. Each employment agreement has an initial term that runs through March 2, 2007. The employment agreements automatically renew each March 3 for an additional one-year period unless prior notice is given. Each employment agreement provides for a base salary, a discretionary bonus, and participation in our benefit plans and programs. Mr. Josey s agreement also provides for life insurance equal to two times his base salary.

The base salaries for 2005 for our Chief Executive Officer and each of our other current named executive officers are as follows: Scott D. Josey $375,000; Mike C. van den Bold $200,000; Dalton F. Polasek $250,000; Judd A. Hansen $187,500; and Teresa G. Bushman $200,000.

Under the employment agreements, the officers are entitled to severance benefits in the event of a resignation for good reason, a termination without cause or, in the case of Mr. Josey s agreement, our non-renewal of the agreement: (i) a payment equal to 2.0 (2.5 for Mr. Polasek and 2.99 for Mr. Josey) times the sum of executive s base salary and three year average annual bonus, (ii) health care coverage for a period of eighteen months (two years for Mr. Josey and Mr. Polasek), (iii) 100% vesting of all restricted shares under our Equity Participation Plan, and (iv) 50% vesting of all other rights under any other equity plans, including our Stock Incentive Plan.

The employment agreements also provide for certain change of control benefits. Upon termination for any reason other than cause at any time on or within nine months after a change of control that occurs while the executive is employed, or upon the occurrence of a change of control within nine months following resignation of employment for good reason or termination without cause, the agreements provide for the following benefits: (i) a lump sum payment equal to 2.0 (2.5 for Mr. Polasek and 2.99 for Mr. Josey) times the sum of the officer s base salary and three year average annual bonus, and (ii) 100% vesting of all rights under any equity plans, including our Equity Participation Plan and our Stock Incentive Plan. The officers are entitled to a full tax gross-up payment if the aggregate payments and benefits to be provided constitute a parachute payment subject to a Federal excise tax.

The agreements also include confidentiality and non-solicitation provisions.

Overriding Royalty Arrangements

Mariner s geologist and geophysicist employees are eligible to participate in the Company s Amended and Restated Gulf of Mexico Overriding Royalty Interest Plan. Pursuant to the terms of the plan, overriding royalty interests (ORRIs) may be awarded to participants in the plan for prospects in the Gulf of Mexico that are generated or identified and acquired during the term of the participant s employment at Mariner. The maximum ORRI for all participants is 1.8% for shelf leases and 0.9% for deepwater leases, subject to proportionate reduction. The maximum ORRI per participant is $^1/2$ of one percent for shelf leases and $^1/4$ of one percent for deepwater leases, subject to proportionate reduction.

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Unless approved by Mariner s overriding royalty interest committee, no ORRIs are awarded for developed or undeveloped reserve acquisitions.

Currently six employees are participants in the plan. None of Mariner s officers or managers are eligible to participate in the plan. Since the inception of the plan in July 2002 through December 31, 2004, approximately $252,000 has been distributed to participants with respect to ORRIs granted to them under the plan.

In 2002, two of our current executive officers, Dalton F. Polasek, Executive Vice President Operations and Exploration and Judd A. Hansen, Vice President Shelf and Onshore, received assignments of ORRIs in certain leases acquired by us under a consulting arrangement. A consulting company owned in part by Mr. Polasek was assigned a 2% ORRI from us in four federal offshore leases as partial consideration for having brought the related prospect to us. With our knowledge and consent, the consulting company subsequently assigned portions of the ORRIs to Mr. Hansen and a company owned by Mr. Polasek. At the time of the assignments, Messrs. Polasek and Hansen served the Company as officers and consultants but were not employed by the Company. No payments were made in respect of these ORRIs until 2004, when each received less than $60,000 with respect to his ORRI.

We may have obligations under previously terminated employment and consulting agreements to assign additional ORRIs in some of our oil and natural gas prospects to current and former employees and consultants. Cory L. Loegering, Vice President of Deepwater, is the only current executive officer who may be entitled to receive ORRIs under any of these agreements.

All ORRIs assigned to these parties are excluded from Mariner s interests evaluated in our reserve report.

Equity Participation Plan

We have adopted an Equity Participation Plan that provided for the one-time grant at the closing of our private equity placement on March 11, 2005 of 2,267,270 restricted shares of our common stock to certain of our employees. No further grants will be made under the Equity Participation Plan, although persons who receive such a grant will be eligible for future awards of restricted stock or stock options under our Stock Incentive Plan described below.

We intended the grants of restricted stock under the Equity Participation Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our common stock. Therefore, Equity Participation Plan grantees did not pay any consideration for the common stock they received, and we received no remuneration for the stock.

The table below includes information regarding the restricted stock awards granted in March of 2005 under the Equity Participation Plan to our chief executive officer, our four other most highly compensated executive officers as of the year 2004, and all officers as a group. Grantees are entitled to vote, and accrue dividends on, the restricted stock prior to vesting; provided, however that any dividends that accrue on the restricted stock prior to vesting will only be paid to grantees to the extent the restricted stock vests.

Equity Participation Plan
Restricted Stock Awards

Officer or Group	No. of Shares	Value at Grant (1)
Scott D. Josey	680,181	$ 9,522,534
Mike C. van den Bold	226,727	3,174,178
Dalton F. Polasek	308,349	4,316,886
Judd A. Hansen	158,709	2,221,926
Teresa G. Bushman	137,170	1,920,380
Officers as a group (8 persons)	1,803,613	25,250,582

(1) Based on a price of $14.00 per share.

Except as described below, the restricted shares will be automatically forfeited in the event a grantee s employment terminates prior to the vesting date of the awards. The restricted stock granted will vest, and restrictions will terminate, on the later of (i) the first anniversary of the grant date, which was March 11, 2005, and (ii) the occurrence of a Public Sale Date ; but in no event later than the second anniversary of the date of grant. For purposes of grants under the Equity Participation Plan, Public Sale Date means the earlier to occur of:

- the 90th day following the date on which our common stock is listed on the New York Stock Exchange or admitted to trading and quoted on the Nasdaq National Market or Nasdaq SmallCap Market; and

- the first date on which both of the following conditions are met: (a) a registration statement covering the resale of the restricted stock has been declared effective by the SEC, and no stop order suspending the effectiveness of such registration statement is in effect and (b) the common stock is listed on the New York Stock Exchange or admitted to trading and quoted on the Nasdaq National Market or Nasdaq SmallCap Market;

provided, however, that if either of the above events occurs and the restricted shares are subject to restrictions on resale as a result of any lock-up agreement or arrangement in connection with a public offering, the Public Sale Date shall be the earlier of the first business day following the date of expiration of the lock-up period and a date 181 days from the date the lock-up period commences.

Notwithstanding the above vesting schedule, the unvested shares of restricted stock will become fully vested upon death or disability of the employee, or if employment is terminated by us for reasons other than for cause, or if the employee elects to terminate employment with good reason, or upon the occurrence of a change of control, as those terms are defined in the agreement with us governing the grant.

In accordance with GAAP, we expect to incur significant compensation expense as a result of the grants of restricted stock under the Equity Participation Plan. See Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies Deferred Compensation Expense for a discussion of these charges.

Stock may be withheld by us upon vesting to satisfy our tax withholding obligations with respect to the vesting of the restricted stock. Participants in the Equity Participation Plan will have the right to elect to have us withhold and cancel shares of the restricted stock to satisfy withholding obligations. In such events, we would be required to pay any tax withholding obligation in cash.

The Equity Participation Plan will be administered by our board of directors. The board of directors may delegate administration of the plan to a committee of the board of directors. The Equity Participation Plan will expire upon the vesting or forfeiture of all shares granted thereunder.

Stock Incentive Plan

We have adopted a Stock Incentive Plan for issuances of equity based awards based on our common stock to our current or future employees and directors. The Stock Incentive Plan consists of two components: restricted stock and stock options. The Stock Incentive Plan limits the number of shares of our common stock that may be delivered pursuant to awards to 2,000,000 shares, 787,360 of which have been granted to certain of our employees at an initial exercise price of $14 per share. Stock withheld to satisfy exercise prices or tax withholding obligations are available for delivery pursuant to other awards. The Stock Incentive Plan is administered by our board of directors. The board of directors may delegate administration of the Stock Incentive Plan to a committee of the board. The table below includes information regarding stock options under the Stock Incentive Plan granted in March of 2005 to our chief executive officer, our four other most highly compensated executive officers in 2004 and all officers as a group.

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Stock Incentive Plan
Grants of Stock Options $14 Exercise Price

Officer or Group	No. of Option Shares
Scott D. Josey	200,000
Mike C. van den Bold	74,000
Dalton F. Polasek	102,000
Judd A. Hansen	48,000
Teresa G. Bushman	40,000
Executive officers as a group (8 persons)	584,000
Employees receiving grants of stock options as a group	787,360

Our board of directors may terminate or amend the Stock Incentive Plan at any time with respect to any shares of stock for which a grant has not yet been made. Our board of directors also has the right to alter or amend the Stock Incentive Plan or any part thereof from time to time, including increasing the number of shares of stock that may be granted subject to stockholder approval. However, no change in the Stock Incentive Plan or in any outstanding grant may be made that would materially reduce the benefits of the participant without the consent of the participant. The Stock Incentive Plan will expire on the earlier of the tenth anniversary of its approval by stockholders or its adoption or its termination by the board of directors. Awards then outstanding will continue pursuant to the terms of their grants.

Restricted Stock. Restricted stock is stock that vests over a period of time and that during such time is subject to forfeiture. At any time in the future, the board of directors may determine to make grants of restricted stock under the Stock Incentive Plan to employees and directors containing such terms as the board of directors shall determine. The board of directors will determine the period over which restricted stock granted to employees and members of our board of directors will vest. The board of directors may base its determination upon the achievement of specified financial or other objectives.

If a grantee s employment or membership on the board of directors terminates for any reason, the grantee s restricted stock will be automatically forfeited unless, and to the extent, the board of directors or the terms of the award agreement provide otherwise. Shares of common stock to be delivered as restricted stock may be newly issued common stock, common stock already owned by us, common stock acquired by us from any other person or any combination of the foregoing. If we issue new common stock upon the grant of the restricted stock, the total number of common stock outstanding will increase.

We intend the restricted stock under the Stock Incentive Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our common stock. Therefore, Stock Incentive Plan participants will not pay any consideration for the common stock they receive, and we will receive no remuneration for the stock.

Stock Options. The Stock Incentive Plan permits the grant of options covering our common stock. Options may be incentive stock options, within the meaning of Section 422 of the Internal Revenue Code, or nonqualified stock options as determined by the board of directors. At any time in the future, the board of directors may determine to make grants under the Stock Incentive Plan to employees and members of our board of directors containing such terms as the committee shall determine. Stock options will have an exercise price that may not be less than the fair market value of the stock on the date of grant. In general, stock options granted will become exercisable over a period determined by the board of directors. If a grantee s employment or membership on the board of directors terminates for any reason, the grantee s unvested stock options will be automatically forfeited unless, and to the extent, the option agreement or the board of directors provides otherwise.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information as of March 11, 2005 with respect to the beneficial ownership of our common stock by (i) 5% stockholders, (ii) current directors, (iii) five most highly compensated executive officers during 2004 and (iv) executive officers and directors as a group.

Unless otherwise indicated in the footnotes to this table, each of the stockholders named in this table has sole voting and investment power with respect to the shares indicated as beneficially owned.

Name of Beneficial Owner	Amount(1)	Percent of Class
5% Stockholder:		
FMR Corp.(2)	4,335,200	12.2%
ACON E&P, LLC(3)	1,895,630	5.3%
Officers and Directors(4)*:*		
Scott D. Josey	680,181	1.9%
Mike C. van den Bold	226,727	*
Dalton F. Polasek	308,349	*
Judd A. Hansen	158,709	*
Teresa G. Bushman	137,170	*
Bernard Aronson(5)	1,895,630	5.3%
Jonathan Ginns(6)	1,895,630	5.3%
Pierre F. Lapeyre, Jr.		
David M. Leuschen		
Executive officers and directors as a group (12 persons)	3,699,244	10.4%

* Less than 1%.

(1) Includes grants of restricted stock to executive officers under our Equity Participation Plan. These shares may be voted, but not disposed of, prior to vesting.

(2) Of the amount shown, 1,847,200 shares are held by Fidelity Contrafund, 1,439,700 shares are held by Fidelity Puritan Fund: Fidelity Low-Priced Stock Fund, 527,600 shares are held by Variable Insurance Products Fund II: Contra-Fund Portfolio, 516,300 shares are held by Fidelity Puritan Trust: Fidelity Balanced Fund, and 4,400 shares are held by Fidelity Management Trust Company on behalf of accounts managed by it. Fidelity may be deemed a beneficial owner of these shares by virtue of its affiliation with these holders of record.

(3) The address of ACON E&P, LLC is c/o ACON Investments LLC, 1133 Connecticut Avenue, N.W., Suite 1100, Washington, D.C. 20036. The shares beneficially owned by ACON E&P, LLC are held of record by MEI Acquisitions Holdings, LLC.

(4) The address of each officer and director is c/o Mariner Energy, Inc., 2101 Citywest Blvd., Suite 1900, Houston, Texas 77042.

(5) Mr. Aronson is a manager of ACON E&P, LLC. Mr. Aronson disclaims beneficial ownership of these shares except to the extent of his pecuniary interest therein. Mr. Aronson s address is c/o ACON Investments, LLC, 1133 Connecticut Avenue, N.W., Suite 1100, Washington, D.C. 20036.

(6)

Mr. Ginns is a managing member of Burns Park Investments LLC, a manager of ACON E&P, LLC. Mr. Ginns disclaims beneficial ownership of these shares except to the extent of his pecuniary interest therein. Mr. Ginns address is c/o ACON Investments, LLC, 1133 Connecticut Avenue, N.W., Suite 1100, Washington D.C. 20036.

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CERTAIN TRANSACTIONS WITH AFFILIATES AND MANAGEMENT

In connection with the merger in March 2004, Mariner Energy LLC, our former indirect parent, entered into management agreements with each of Carlyle/ Riverstone Energy Partners II, L.P. (C/R Energy Partners) and ACON E&P III, LLC (ACON E&P), pursuant to which we paid aggregate fees in the amount of $2,500,000 to C/R Energy Partners and ACON E&P. C/R Energy Partners was, and ACON E&P is, an affiliate of MEI Acquisitions Holdings, LLC, our former sole stockholder. No additional fees are payable under these agreements.

Under a C/R Monitoring Agreement with C/R Energy Partners and under an ACON Monitoring Agreement with ACON, each dated as of March 2, 2004, we were obligated to pay monitoring fees in the aggregate amount of 1% of our annual consolidated EBITDA to C/R Energy Partners and ACON payable on a calendar quarter basis. We accrued $1.4 million in monitoring fees under these agreements for 2004. The parties terminated these agreements on February 7, 2005 in return for lump sum cash payments by Mariner totalling $2.3 million.

We used $166 million of the net proceeds from our sale of 12,750,000 share of common stock in our recent private placement to purchase and retire an equal number of shares of our common stock shares then held by MEI Acquisitions Holdings, LLC, our former sole stockholder.

The estimated $1.9 million in expenses related to the recent private placement included approximately $.8 million of expenses incurred by our former sole stockholder, MEI Acquisitions Holdings, LLC, and its members in connection with the offering.

We currently have obligations concerning ORRI arrangements with two of our officers who received assignments of ORRIs in certain leases acquired by us under a consulting agreement and with another officer who may be entitled to assignments of ORRIs under a previously terminated employment agreement, as described in Management Overriding Royalty Arrangements.

SELLING STOCKHOLDERS

This prospectus covers shares currently owned by an affiliate of our former sole stockholder as well as shares sold in our recent private equity placement. Some of the shares sold in the private equity placement were sold directly to accredited investors as defined by Rule 501(a) under the Securities Act pursuant to an exemption from registration provided in Regulation D, Rule 506 under Section 4(2) of the Securities Act. In addition, we and our former sole stockholder sold shares to FBR, who acted as initial purchaser and sole placement agent in the offering. FBR sold the shares it purchased from us and our sole stockholder in transactions exempt from the registration requirements of the Securities Act to persons that it reasonably believed were qualified institutional buyers, as defined by Rule 144A under the Securities Act or to non-U.S. persons pursuant to Regulation S under the Securities Act. An affiliate of our former sole stockholder, the selling shareholders who purchased shares from us or FBR in the private equity placement and their transferees, pledgees, donees, assignees or successors, may from time to time offer and sell under this prospectus any or all of the shares listed opposite each of their names below.

The following table sets forth information about the number of shares owned by each selling stockholder that may be offered from time to time under this prospectus. Certain selling stockholders may be deemed to be underwriters as defined in the Securities Act. Any profits realized by the selling stockholder may be deemed to be underwriting commissions.

The table below has been prepared based upon the information furnished to us by the selling stockholders as of March 30, 2005. The selling stockholders identified below may have sold, transferred or otherwise disposed of some or all of their shares since the date on which the information in the following table is presented in transactions exempt from or not subject to the registration requirements of the Securities Act. Information concerning the selling stockholders may change from time to time and, if necessary, we will supplement this prospectus accordingly. We cannot give an estimate as to the amount of shares of common stock that will be held by the selling stockholders upon termination of this offering because the selling stockholders may offer some or all of their common stock under the offering

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contemplated by this prospectus. The total amount of shares that may be sold hereunder will not exceed the number of shares offered hereby. Please read Plan of Distribution.

Except as noted below, to our knowledge, none of the selling stockholders has, or has had within the past three years, any position, office or other material relationship with us or any of our predecessors or affiliates, other than their ownership of shares described below.

Selling Stockholder	Number of Shares of Common Stock That May Be Sold	Percentage of Common Stock Outstanding
ACON E&P, LLC(1)	1,895,630	5.32%
ADAR Investment Fund Ltd	350,000	*
Alexander, Leslie	450,000	1.26%
Alexandra Global Master Fund, Ltd	350,000	*
Alexis A. Shehata-Personal Portfolio	1,840	*
Allied Funding, Inc.	17,000	*
Alpha US Sub Fund 1, LLC	31,400	*
America	40,000	*
Anita L. Rankin Revocable Trust-U/ A DTD 4/28/1995-Anita L. Rankin, TTEE	380	*
Ann K. Miller-Personal Portfolio	6,300	*
Anne Marie Romer-Personal Portfolio	1,290	*
Anthony L. Kremer Revocable Living Trust-U/ A DTD 1/27/1998-Anthony L. Kremer TTEE	1,000	*
Anthony L. Kremer-IRA	1,010	*
Atlas (QP), LP	5,550	*
Atlas Capital (Q.P.), L.P.	102,600	*
Atlas Capital Master Fund Ltd	197,400	*
Atlas Master Fund	10,920	*
Auto Disposal Systems-401(k)-All Cap Value Account	650	*
Auto Disposal Systems-401(k)-Balanced 60 Account	480	*
Auto Disposal Systems-401(k)-Small Cap Value Account	850	*
Aviation Sales Inc.-401(k) Profit Sharing Plan-Rick J. Penwell TTEE	1,470	*
Axia Offshore Partners, LTD	143,500	*
Axia Partners Qualified, LP	258,950	*
Axia Partners, LP	66,150	*
Baker-Hazel Funeral Home, Inc.-401(k) Plan	550	*
Baker-Hazel Funeral Home-Corporate Investment Fund	330	*
Basso Multi-Strategy Holding Fund Ltd	56,550	*
Basso Private Opportunity Holding Fund Ltd.	15,950	*
BBT Fund, L.P.	505,811	1.42%
BBVA	321,429	*
Beach, Patrick & Christine	6,666	*
Belmont, Francis E	1,500	*

Bennett Family LLC	2,000	*
Benny L. & Alexandra P. Tumbleston JT WROS	1,890	*
Bermuda Partners, LP	33,000	*
Black Sheep Partners, LLC	18,000	*
BLT Enterprises, LLLP-Partnership	1,100	*
Blueprint Partners, L.P.	20,000	*
Borman, Casey 1	5,000	*
Boston Partners All Cap Value Fund	1,875	*

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Selling Stockholder	Number of Shares of Common Stock That May Be Sold	Percentage of Common Stock Outstanding
Bradley J. Hausfeld-IRA	400	*
Brady Partners	27,500	*
Brunswick Master Pension Trust	23,600	*
Calm Waters Partnership	142,857	*
Camine Guerro-IRA Rollover	2,090	*
Canyon Capital Balanced Equity Master Fund, Ltd	71,429	*
Canyon Value Realization Fund (Cayman) Ltd.	500,000	1.40%
Canyon Value Realization Fund L.P.	121,428	*
Canyon Value Realization MAC- 18 Ltd	7,143	*
Carmine and Wendy Guerro Living Trust-U/ A DTD 7/31/2000-C Guerro and W Guerro, TTEES	1,080	*
Carol D. Shellabarger Green-Revocable Trust DTD 4/21/00-Carol Downing Green TTEE	890	*
Carol Downing Green-IRA	470	*
Carol V. Hicks-Personal Portfolio	30	*
Castle Rock Fund Ltd	126,800	*
Castlerock Partners II, L.P.	15,800	*
Castlerock Partners, L.P.	392,000	1.10%
Catalyst Fund Offshore Ltd.	3,242	*
Caxton International Limited	375,000	1.05%
Ceisel, Charles B	1,500	*
Chamberlain Investments Ltd.	8,762	*
Charles L. & Miriam L. Bechtel-Joint Personal Portfolio	450	*
Cheyne Special Situations Fund LP	200,000	*
Chimermine, Lawrence	2,000	*
Christine Hausfeld-IRA	160	*
Christopher M. Ruff-IRA Rollover	200	*
Cindu International Pension Fund	2,900	*
Citi Canyon Ltd	7,143	*
Clam Partners, LLC	36,000	*
Clark Manufacturing Co.-Pension Plan DTD 5/16/1998-John A. Barron TTEE	180	*
Clark Manufacturing Co.-PSP DTD 5/16/98-John A. Barron TTEE	360	*
Concentrated Alpha Partners, L.P.	185,619	*
Congress Ann Hazel-IRA	590	*
Cynthia Mollica Barron-Personal Portfolio	150	*
David Keith Ray-IRA	940	*
David M. Morad Jr.-IRA Rollover	2,800	*
	1,230	*

David R. Kremer Revocable Living Trust-DTD 5/7/1996-David R. Kremer & Ruth E. Kremer, TTEES		
Deanne W. Joseph-IRA Rollover	370	*
Delaware Street Capital Master Fund L.P.	650,000	1.83%
Deutsche Bank AG London	53,571	*
Don A. Keasel and Judith Keasel-JTWROS	120	*
Don Keasel-IRA Rollover	810	*
Donald G. Tekamp Revocable Trust-DTD 8/16/2000-Donald G. Tekamp TTEE	1,460	*
Donald L. and Edythe Aukeman-Joint Personal Portfolio	400	*

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Selling Stockholder	Number of Shares of Common Stock That May Be Sold	Percentage of Common Stock Outstanding
Donald L. Aukerman-IRA	620	*
Donna M. Ruff-IRA Rollover	80	*
Dorothy W. Savage-Kemp-IRA	440	*
Dorothy W. Savage-Kemp-TOD	820	*
Douglas & Melissa Marchal-Joint Personal Portfolio	290	*
Dr. Donald H. Nguyen & Lynn A. Buffington-JTWROS	540	*
Dr. Juan M. Palomar-IRA Rollover	1,520	*
Drake Associates LP	38,929	*
Edenworld International Ltd.	4,470	*
Edison Sources Ltd.	33,600	*
Edward W. Eppley-IRA SEP	600	*
Edythe M. Aukeman-IRA	140	*
Elaine S. Berman Trust-DTD 6/30/95-Elaine S. Berman TTEE	550	*
Elaine S. Berman-Inherited IRA-Beneficiary of Freda Levine	460	*
Elaine S. Berman-SEP-IRA	540	*
Electrical Workers Pension Funds Part A	1,855	*
Electrical Workers Pension Funds Part B	1,335	*
Electrical Workers Pension Funds Part C	645	*
Emerson Electric Company	32,300	*
Emerson Partners	60,000	*
Emerson, J. Steven	200,000	*
Emerson, J. Steven IRA R/ O II	740,000	2.08%
Emerson, J. Steven Roth IRA	400,000	1.12%
Endeavor Asset Management	20,000	*
Ernst Enterprises-Deferred Compensation DTD 05/20/90-fbo Mark Van de Grift	1,360	*
Ernst Enterprises-Deferred Compensation Plan DTD 05/20/90-fbo Terry Killian	1,560	*
Event Trading Ltd	550,000	1.54%
Excelsior Value and Restructuring Fund	1,200,000	3.37%
Farallon Capital Institutional Partners II, L.P.	10,700	*
Farallon Capital Institutional Partners III, L.P.	12,500	*
Farallon Capital Institutional Partners, L.P.	128,600	*
Farallon Capital Offshore Investors, Inc.	364,300	1.02%
Farallon Capital Partners, L.P.	194,586	*
Farvane Limited	1,216	*
FBO Marjorie G. Kasch-U/ A/ D 3/21/80-Thomas A. Holton TTEE	700	*
Fidelity Contrafund(2)	1,847,200	5.19%
	4,400	*

Fidelity Management Trust Company on behalf of accounts managed by it(3)		
Fidelity Puritan Trust: Fidelity Balanced Fund(2)	516,300	1.45%
Fidelity Puritan Trust: Fidelity Low-Priced Stock Fund(2)	1,439,700	4.04%
Flagg Street Offshore, LP	86,725	*
Flagg Street Partners LP	41,395	*
Flagg Street Partners Qualified LP	46,880	*
Fleet Maritime, Inc.	19,731	*
Fondo America	40,000	*

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Selling Stockholder	Number of Shares of Common Stock That May Be Sold	Percentage of Common Stock Outstanding
Fondo Attivo	17,000	*
Fondo Trading	55,000	*
Fort Mason Master, L.P.	188,100	*
Fort Mason Partners, L.P.	11,900	*
Framtidsfonden	25,000	*
Gallatin, Ronald	25,000	*
Gary M. Youra, M.D.-IRA Rollover	2,060	*
Geary Partners	95,000	*
George Hicks-Personal Portfolio	860	*
Gerald Allen-IRA	420	*
Gerald E. & Deanne W. Joseph-Joint Personal Portfolio	1,180	*
Gerald J. Allen-Personal Portfolio	3,580	*
GLG Market Neutral Fund	178,570	*
GLG North American Opportunity Fund	892,859	2.50%
Global Capital Ltd.	20,000	*
GMI Master Retirement Trust	33,395	*
Goldman Sachs & Co., Inc.	317,756	*
Goldstein, Robert B. & Candy K	4,000	*
Gracie Capital International	225,000	*
Gracie Capital LP	150,000	*
Greek, Cathy & Frank	3,900	*
Gregory A. & Bibi A. Reber-Joint Personal Portfolio	580	*
Gregory J. Thomas-IRA SEP	370	*
Grelsamer, Philippe	2,500	*
Growth Opportunities Trading Ltd	410,000	1.15%
Gruber & McBaine International	15,000	*