MARINER ENERGY INC
Form S-1/A
July 26, 2005

Table of Contents

As filed with the Securities and Exchange Commission on July 26, 2005

Registration No. 333-124858

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

Amendment No. 1
to
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., Bldg. 4, Suite 900
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.
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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

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.

Table of Contents

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 July 26, 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 have applied to list our common stock on The Nasdaq Stock Market under the symbol MRNR.

Investing in our common stock involves risks. You should read the section entitled Risk Factors beginning on page 8 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.

TABLE OF CONTENTS

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

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 8 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 Annex 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 89 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. As of December 31, 2004, the present value, discounted at 10% per annum, of estimated future net revenues from our proved reserves, before income tax, (PV10) was approximately $668 million, and our standardized measure of discounted future net cash flows attributable to our proved reserves was approximately $494 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
West Texas Permian Basin	8.7	62.8	114.8	48%
Gulf of Mexico Deepwater(2)	4.5	59.8	86.7	37%
Gulf of Mexico Shelf(3)	1.1	29.3	36.0	15%
Total	14.3	151.9	237.5	100%

(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 Annex A to this prospectus.

(2) 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)).

(3) 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 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.

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, which has produced oil and gas since 1949. 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 and North Stiles Units are located in the heart of the Spraberry geologic trend southeast of Midland, Texas. 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. During the five months ended May 31, 2005, we drilled 36 wells at our Aldwell and North Stiles Units. All of our drilling in the Aldwell and North Stiles Units has resulted in commercially successful wells that are expected to produce in quantities sufficient to exceed costs of drilling and completion. 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.

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 the second half of 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.

Table of Contents

Recent Developments

Recent Tropical Storm Cindy and Hurricanes Dennis and Emily did not cause any significant damage to any of our projects in the Gulf of Mexico. However, as a precaution prior to Hurricane Dennis, workers and equipment were evacuated from several of our producing platforms and our Pluto and Baccarat development projects. The storm interruptions resulted in temporary shut-in of production at Ewing Bank 966 (Black Widow), Green Canyon 472/473 (King Kong) and Mississippi Canyon 357 and minor delays of our development activities at our Pluto and Baccarat projects. Production was restored to full capacity after the storm passed.

Operations. During the first five months of 2005, we drilled 36 wells in the Aldwell and North Stiles Units, all of which were commercially successful and are expected to produce in quantities sufficient to exceed costs of drilling and completion. We recently completed construction of our own oil and gas gathering lines and compression facilities in the Aldwell Unit. We began flowing production through the new facilities on June 1, 2005. We have also entered into new contracts with third parties to provide processing of our natural gas and transportation of our oil in the unit. The new gas arrangement also provides us with the option to sell our gas to one of four firm or five interruptible sales pipelines versus a single outlet under the former arrangement. 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 awarded the West Cameron 386 block located in water depth of approximately 85 feet.

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 a lower rate than expected from a zone that appears to be compartmentalized. We expect the Dice well to be sidetracked in the second half of 2005 to access a better location in the producing horizon.

New production from our Swordfish and Pluto 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, production from Swordfish and Pluto is now expected to commence in the third quarter of 2005 and production from Ochre is expected to commence in the fourth 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. Viosca Knoll 917 (Swordfish), Mississippi Canyon 718 (Pluto) 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 and Rigel has been delayed beyond our earlier forecasts due to factors outside our control.

Production at Swordfish was delayed 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 the third quarter of 2005.

Table of Contents

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) delayed the safe unloading and installation of subsea facilities at the Pluto site until June 2005. Installation of the undersea facilities is now complete and we anticipate production to recommence in the third quarter of 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. We recently executed an agreement to tie in production to a nearby replacement host facility and anticipate production to recommence in the fourth 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.

Capital Budget Changes and Future Development Plans. In June 2005, the board of directors approved an increase in our capital expenditure budget from approximately $152 million to approximately $271 million. The increase in anticipated capital expenditures from the prior estimate is primarily related to the following new or accelerated projects.

High Island A341 (Capricorn)   In May 2005 we drilled the Capricorn discovery well, which encountered approximately 104 net feet of pay in four zones. The Capricorn project is located approximately 115 miles south southwest of Cameron, Louisiana in approximately 240 feet of water. We anticipate drilling an appraisal well and installing the necessary platform and facilities in the fourth quarter of 2005, with first production anticipated in 2006. We are the operator and own a 60% working interest in the project.

Atwater Valley 380, 381, 382, 425 and 426 (Bass Lite)   We acquired an additional 18.75% interest in the Bass/ Bass Lite project effective April 25, 2005, increasing our total working interest in this project to 38.75%. Mariner paid $5 million, and the seller retained a .94% net overriding royalty interest before project payout changing to a 2.3% net overriding royalty interest after project payout. The Bass Lite project is located approximately 200 miles southeast of New Orleans in approximately 6,500 feet of water. The blocks contain an undeveloped discovery and exploration potential. Mariner has been elected operator of the project, subject to MMS approval, and has budgeted the drilling of an appraisal well in the fourth quarter of 2005 subject to drill ship availability.

LaSalle/ NW Nansen Project Development   In June 2005 we increased our working interest in the LaSalle project (East Breaks 558, 513 and 514) to 100% by acquiring the remaining working interest owned by a third party for $1.5 million. The seller retained a 2.5% net overriding royalty interest in the project. The blocks contain an undeveloped discovery and exploration potential. We have also executed a participation agreement with Kerr McGee to jointly develop the LaSalle project and Kerr McGee s nearby NW Nansen exploitation project (East Breaks 602). Under the agreement, Mariner owns a 33% working interest in the NW Nansen project and a 50% working interest in the LaSalle project. The LaSalle and NW Nansen projects are located approximately 150 miles south of Galveston, Texas in water depths of approximately 3,100 and 3,300 feet, respectively. The development of these projects may require the drilling of up to four wells in 2005 and related completion and facility capital in 2006.

Green Canyon 516, 472 and 473 (King Kong/ Yosemite Project Development)   In conjunction with the operator, we have planned a two well drilling program at the King Kong/ Yosemite field

Table of Contents

to exploit potential new reserve additions. We anticipate drilling one exploration well and one development well the first on block 472 in 2005 and the second on block 473 in 2006. We own a 50% working interest in blocks GC 472 and 473 and a 44% working interest in block 516.

We also allocated a portion of the increase in our capital budget for the potential acquisition of additional onshore properties. We are currently negotiating with a private party to acquire and jointly develop working interests located in the Spraberry geologic trend in West Texas. Once a binding agreement is executed, details about the proposed transaction will be made available.

The increased capital expenditures will be funded from cash flows and our existing bank facility. We recently requested an increase in our bank borrowing base from $135 million in anticipation of the projected increased capital requirements. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources. Our current capital budget for 2005 may be subject to further 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.

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.

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.

Summary of Capital Expenditures

The following tables summarize information regarding our 2004 and current budgeted 2005 capital expenditures. The current budgeted 2005 capital expenditures are subject to change depending upon 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.

	2004 Capital Expenditures	2005 Budgeted Capital Expenditures
Development Expenditures		
Gulf of Mexico Deepwater	$ 43.6	$ 76.8
Gulf of Mexico Shelf	24.7	25.7
West Texas Permian Basin	20.3	40.0
Total Development Capital Expenditures	$ 88.6	$ 142.5
Exploration Expenditures		
Exploratory Drilling		
Gulf of Mexico Deepwater	$ 19.9	$ 47.1
Gulf of Mexico Shelf	13.6	21.0
Leasehold Acquisition	3.5	6.1
Delay Rentals	1.3	1.5
Geological & Geophysical	9.6	8.7
Total Exploration Capital Expenditures	$ 47.9	$ 84.4

Total Development and Exploration Capital Expenditures	$	136.5	$	226.9
Property Acquisitions		4.9		36.1
Capitalized Overhead and Interest		7.3		7.4
Total Capital Expenditures(1)	$	148.7	$	270.4

5

Table of Contents

(1) 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. Total Capital Expenditures of $148.7 million for 2004 exclude approximately $0.2 million of additions to other property and equipment, primarily related to leasehold improvements and office equipment, and 2005 Budgeted Capital Expenditures of $270.4 million exclude $0.3 million budgeted for other property and equipment.

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 was acquired by 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, through a merger of Mariner s former indirect parent with MEI. 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., Bldg. 4, Suite 900, Houston, Texas 77042-2831, and our telephone number is (713) 954-5500.

Table of Contents

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 have applied to list our common stock on The Nasdaq Stock Market under the symbol MRNR.
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 8 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.

Table of Contents

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 reduce our revenues, profitability and cash flow 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, which may lower our bank borrowing base and reduce our access to capital.

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.

Table of Contents

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 reduce our revenue, profitability and cash flow materially.

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. During the three years ended December 31, 2002, 2003 and 2004, weather and mechanical problems affecting our offshore producing properties resulted in aggregate downtime for our offshore producing properties of 7.3%, 7.1% and 7.3%, respectively.

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 reduce our levels of production, cause substantial losses or prevent us from realizing profits.

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

- fires;

explosions;

Table of Contents

- 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 increase our cost of operations and adversely affect our ability to produce oil and gas.

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 PV10, 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.

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. The reviews we conduct of acquired properties prior to acquisition are not capable of identifying all potential adverse 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

Table of Contents

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.

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, which could have a material adverse effect on our financial condition and results of operations.

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 giving them an advantage in evaluating and obtaining properties and prospects.

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, and therefore we may not be in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves.

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.

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 798,960 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.

Table of Contents

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

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. We disclose important factors that could cause our actual results to differ materially from our expectations under Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this prospectus. 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.

Table of Contents

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 capitalization as of March 31, 2005. 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.

		March 31, 2005 (in millions)
Long-term debt:		
Credit facility revolving note due March 2007	$	55.0
Promissory note to former indirect stockholder(1)		4.0
Total long-term debt		59.0
Stockholders equity(2)		178.2
Total capitalization	$	237.2

(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.

Table of Contents

DILUTION

Our net tangible book value as of March 31, 2005 was $5.00 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 $9.00 in the net tangible book value per share of our common stock assuming a sale price of $14.00 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		$ 14.00
Net tangible book value per share at March 31, 2005	$ 5.00	
Increase per share attributable to new investors	-0-	
Net tangible book value per share after this offering		5.00
Dilution per share to new investors		$ 9.00

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.

Table of Contents

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 and the three-month periods ended March 31, 2004 and 2005. In addition, the table includes combined historical financial data for the three-month period ended March 31, 2004 and the year ended December 31, 2004, which combines our results of operations for the periods prior to and after the March 2, 2004 merger in which we were acquired by MEI Acquisitions Holdings, LLC. The merger resulted in the application of push-down accounting, whereby our financial statements after the transaction reflect the fair value of our assets and liabilities at the transaction date. The combined data does not reflect the adjustments to our statement of operations that would be reflected in pro forma financial statements. However, because we believe that such adjustments are not material, we believe that the combined data presents a fair presentation and facilitates an understanding of our results of operations for 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 the information in the following table, including pro forma information regarding the merger. Our historical results are not necessarily indicative of results to be expected in future periods.

	Post-Merger		Post-Merger	Pre-Merger		Post-Merger	Pre-Merger	Pre-Merger			
	Three Months Ended March 31, 2005	Combined(1) Three Months Ended March 31, 2004	Period from March 3, 2004 through March 31, 2004	Period from January 1, 2004 through March 2, 2004	Combined(2) Year Ended December 31, 2004	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004	Year Ended December 31, 2003	2002	2001	2000
	(unaudited)	(unaudited)	(unaudited)		(unaudited)						
	(in millions, except per share data)										
Statement of Operations Data:											
Total revenues	$ 55.8	$ 61.0	$ 21.2	$ 39.8	$ 214.2	$ 174.4	$ 39.8	$ 142.5	$ 158.2	$ 155.0	$ 121.1
Lease operating expenses	6.2	7.2	3.1	4.1	25.5	21.4	4.1	24.7	26.1	20.1	17.2
Transportation expenses	1.0	1.7	0.7	1.1	3.0	1.9	1.1	6.3	10.5	12.0	7.8
Depreciation, depletion and amortization	15.1	16.9	6.2	10.6	64.9	54.3	10.6	48.3	70.8	63.5	56.8
Impairment of production					1.0	1.0					

equipment held for use											
Derivative settlement								3.2			
Impairment of Enron related receivables									3.2	29.5	
General and administrative expenses	5.2	2.7	1.5	1.1	8.8	7.6	1.1	8.1	7.7	9.3	6.5
Operating income	28.3	32.5	9.7	22.9	111.0	88.2	22.9	51.9	39.9	20.6	32.8
Interest income	0.5	0.1		0.1	0.3	0.2	0.1	0.8	0.4	0.7	0.1
Interest expense	(1.8)	(0.7)	(0.7)		(6.0)	(6.0)		(7.0)	(10.3)	(8.9)	(11.0)
Income before income taxes	27.0	31.9	9.0	23.0	105.3	82.4	23.0	45.7	30.0	12.4	21.9
Provision for income taxes	(9.2)	(11.1)	(3.1)	(8.1)	(36.9)	(28.8)	(8.1)	(9.4)			
Income before cumulative effect of change in accounting method net of tax effects	17.8	20.8	5.9	14.9	68.4	53.6	14.9	36.3	30.0	12.4	21.9
Income before cumulative effect per common share											
Basic	0.58	0.70	0.20	.50	2.30	1.80	.50	1.22	1.01	.42	.74
Diluted	0.58	0.70	0.20	.50	2.30	1.80	.50	1.22	1.01	.42	.74
Cumulative effect of changes in								1.9			

accounting method											
Net income	$ 17.8	$ 20.8	$ 5.9	$ 14.9	$ 68.4	$ 53.6	$ 14.9	$ 38.2	$ 30.0	$ 12.4	$ 21.9
Net income per common share											
Basic	0.58	0.70	0.20	.50	2.30	1.80	.50	1.29	1.01	.42	.74
Diluted	0.58	0.70	0.20	.50	2.30	1.80	.50	1.29	1.01	.42	.74
Capital Expenditure and Disposal Data:											
Exploration, including leasehold/seismic	$ 1.2	$ 9.9	$ 2.4	$ 7.5	$ 47.9	$ 40.4	$ 7.5	$ 31.6	$ 40.4	$ 66.3	$ 46.7
Development and other	40.9	10.2	2.4	7.8	101.0	93.2	7.8	51.7	65.7	98.2	61.4
Proceeds from property conveyances								(121.6)	(52.3)	(90.5)	(29.0)
Total capital expenditures net of proceeds from property conveyances	$ 42.1	$ 20.1	$ 4.8	$ 15.3	$ 148.9	$ 133.6	$ 15.3	$ (38.3)	$ 53.8	$ 74.0	$ 79.1

Table of Contents

	Post-Merger		Pre-Merger			
			December 31,			
	March 31, 2005	December 31, 2004	2003	2002	2001	2000
	(unaudited)					
	(in millions)					
Balance Sheet Data:(3)						
Property and equipment, net, full cost method	$ 328.3	$ 303.8	$ 207.9	$ 287.6	$ 290.6	$ 287.8
Total assets	418.8	376.0	312.1	360.2	363.9	335.4
Long-term debt, less current maturities	59.0	115.0		99.8	99.8	129.7
Stockholder s equity	178.2	133.9	218.2	170.1	180.1	141.9
Working capital (deficit)(4)	(27.5)	(18.7)	38.3	(24.4)	(19.6)	(15.4)

(1) The combined information for the three months ended March 31, 2004 includes the pre-merger information for the period from January 1, 2004 through March 2, 2004 and the post-merger information for the period from March 3, 2004 through March 31, 2004.
(2) The combined information for the year ended December 31, 2004 includes the pre-merger information for the period from January 1, 2004 through March 2, 2004 and the post-merger information for the period from March 3, 2004 through December 31, 2004.
(3) 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.
(4) Working capital (deficit) excludes current derivative assets and liabilities, deferred tax assets and restricted cash.

	Post-Merger		Post-Merger	Pre-Merger		Post-Merger	Pre-Merger	Pre-Merger			
		Combined(1)									
	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004	Period from March 3, 2004 through March 31, 2004	Period from January 1, 2004 through March 2, 2004	Combined(2) Year Ended December 31, 2004	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004	Year Ended December 31, 2003	2002	2001	2000
	(unaudited)	(unaudited)	(unaudited)		(unaudited)						
	(all amounts in millions)										
Other Financial Data:											
EBITDA(3)	$ 43.5	$ 49.4	$ 15.9	$ 33.4	$ 176.9	$ 143.5	$ 33.4	$ 100.3	$ 113.9	$ 113.6	$ 89.6

Net cash provided by operating activities	49.0	25.5	5.2	20.3	156.2	135.9	20.3	103.5	60.3	113.5	63.9
Net cash (used) provided by investing activities	(42.1)	(20.1)	(4.8)	(15.3)		(133.6)	(15.3)	38.3	(53.8)	(74.0)	(79.1)
Net cash (used) provided by financing activities	(8.0)	(31.2)	(31.2)			64.9		(100.0)		(30.0)	17.4
Reconciliation of Non- GAAP Measures:											
EBITDA	$ 43.5	$ 49.4	$ 15.9	$ 33.4	$ 176.9	$ 143.5	$ 33.4	$ 100.3	$ 113.9	$ 113.6	$ 89.6
Changes in working capital	4.8	(23.3)	(10.0)	(13.2)	(6.3)	6.9	(13.2)	21.8	(20.4)	7.5	(15.5)
Non-cash hedge gain(4)	(1.4)				(7.9)	(7.9)		(2.0)	(23.2)		
Amortization/other	0.3				0.8	0.8			(0.1)	0.6	0.7
Stock compensation expense	1.3										
Net interest expense	(1.3)	(0.6)	(0.7)	0.1	(5.7)	(5.8)	0.1	(6.2)	(9.9)	(8.2)	(10.9)
Income tax expense	1.8				(1.6)	(1.6)		(10.4)			
Net cash provided by operating activities	$ 49.0	$ 25.5	$ 5.2	$ 20.3	$ 156.2	$ 135.9	$ 20.3	$ 103.5	$ 60.3	$ 113.5	$ 63.9

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

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

(3) EBITDA means earnings before interest, income taxes, depreciation, depletion and amortization. For the three months ended March 31, 2005, EBITDA includes $1.3 million in non-cash stock compensation expense related to restricted stock granted in the first quarter of 2005. 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 financial

Table of Contents

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.

(4) 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 recognized all market value changes subsequent to such de-designation in our 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.

Table of Contents

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 push-down purchase accounting at the March 2, 2004 merger date. The application of push-down accounting had no effect on our 2004 results of operations other than immaterial increases in depreciation, depletion and amortization expense and interest expense and a related decrease in our provision for income taxes. 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), Combined (for the full period from January 1 through December 31, 2004), Post-Merger (for the March 3, 2004 through March 31, 2004 period) and Combined (for the full period from January 1, 2004 through March 31, 2004). The combined presentation does not reflect the adjustments to our statement of operations that would be reflected in a pro forma presentation. However, because such adjustments are not material, we believe that our combined presentation presents a fair presentation and facilitates an understanding of our results of operations.

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, which generated approximately $229 million of gross proceeds, or approximately $211 million net of initial purchaser s discount, placement fee and offering expenses. Our former sole stockholder, MEI Acquisitions Holdings, LLC, also sold 15,102,500 shares of our common stock in the private placement. We used $166 million of the net proceeds from the sale of 12,750,000 shares of common stock to purchase and retire an equal number of shares of our common stock from our former sole stockholder. We used $39 million of the remaining net proceeds of approximately $45 million to repay borrowings drawn on our credit facility, and the balance to pay down $6 million of a $10 million promissory note payable to JEDI. See Business Enron Related Matters. As a result of the private placement transaction, 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.

First Quarter 2005 Highlights

During the first quarter of 2005, we recognized net income of $17.8 million on total revenues of $55.8 million compared to net income of $20.8 million on total revenues of $61.0 million in the first quarter of 2004. Net income decreased 14% compared to the first quarter of 2004, primarily the result of a 20% decrease in oil and gas production, partially offset by a 21% improvement in net realized commodity prices by us (before the effects of hedging). Our hedging results also contributed to the decrease in net income as we recorded a $3.9 million loss for the three months ended March 31, 2005 compared to a gain of $1.9 million for the same period in 2004.

Our first quarter 2005 results reflect the private placement of an additional 3.6 million shares of stock in March. The net proceeds of approximately $45 million generated by the private placement were used to repay existing debt. We also granted 2,267,270 shares of restricted stock and options to purchase 787,350 shares of stock in March and recorded compensation expense of $1.3 million in the first quarter of 2005 related to the restricted stock.

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.

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

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. Our first quarter 2005 production averaged approximately 59 MMcf of natural gas per day and approximately 5,500 barrels of oil per day or a total of approximately 92 MMcfe per day.

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) remained 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.

Deepwater discoveries typically require a longer lead time to bring to productive status. Since 2001, we have made several deepwater discoveries that are in various stages of development. We currently anticipate commencing production in the second half of 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

In the three months ended March 31, 2005, we incurred approximately $42.1 million in capital expenditures with 92% related to development activities primarily at our Aldwell Unit and for our Viosca Knoll 917 (Swordfish) and Mississippi Canyon 718 (Pluto) offshore projects. First quarter 2005 development expenditures also included $3.5 million for oil and gas property interests acquired in the West Texas Permian Basin area. We incurred approximately $1.2 million of exploration capital expenditures in the first quarter of 2005.

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 $271 million with approximately 53% allocated to development projects, 31% to exploration activities, 13% 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 PV10 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

Table of Contents

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.

Since December 31, 1997, we have added proved undeveloped reserves attributable to 11 deepwater projects. Of those projects, seven have either been converted to proved developed reserves or sold as indicated in the following table.

Property	Net Proved Undeveloped Reserves (Bcfe)(1)	Year added	Year converted to proved developed or sold
Mississippi Canyon 718 (Pluto)(2)	25.1	1998	2000 (100% converted to proved developed)
Ewing Bank 966 (Black Widow)	14.0	1999	2000 (100% converted to proved developed)
Mississippi Canyon 773 (Devils Tower)	28.0	2000	2001 (100% of Mariner s interest sold)
Mississippi Canyon 305 (Aconcagua)	19.2	2000	2001 (100% of Mariner s interest sold)
Green Canyon 472/473 (King Kong)	25.5	2000	2002 (100% converted to proved developed)
Green Canyon 516 (Yosemite)	14.9	2001	2002 (100% converted to proved developed)
East Breaks 79 (Falcon)	66.8	2001	2002 (50% of Mariner s interest sold) 2003 (all of Mariner s remaining interest sold)

(1) Net proved undeveloped reserves attributable to the project in the year it was first added to our proved reserves.

(2) This field was shut-in in April 2004 pending the drilling of a new well and installation of an extension to the existing infield flowline and umbilical. As a result, as of December 31, 2004, 9.0 Bcfe of our net proved reserves attributable to this project were classified as proved undeveloped reserves. We expect production from Pluto to recommence in the third quarter of 2005, which should result in the reserves associated with this project being reclassified as proved developed before the end of 2005.

The proved undeveloped reserves attributable to the remaining four deepwater projects were added as follows:

Property	Net Proved Undeveloped Reserves (Bcfe)(1)	Year added	Year expected to convert to proved developed status
Viosca Knoll 917 (Swordfish)	13.4	2001	2005

Mississippi Canyon 296/252 (Rigel)	22.4	2003	2005
Green Canyon 646 (Daniel Boone)	16.4	2003	2007
Green Canyon 178 (Baccarat)	4.0	2004	2005

(1) Net proved undeveloped reserves attributable to the project as of December 31, 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.

Lease operating expenses were $6.2 million for the three months ended March 31, 2005, or $0.74 per Mcfe and transportation expenses were $1.0 million or $0.12 per Mcfe for the first quarter of 2005.

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.

General and administrative expenses were $5.2 million for the three months ended March 31, 2005, or $0.62 per Mcfe, including $1.3 million, or $0.16 per Mcfe in compensation expense related to restricted stock granted in March 2005 and $2.3 million or $0.27 per Mcfe related to payments to terminate financial advisory agreements with former stockholders.

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.

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.

Table of Contents

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.

Three Months Ended March 31, 2005 compared to Three Months Ended March 31, 2004

Net production during the three months ended March 31, 2005 decreased approximately 20% to 8.3 Bcfe from 10.3 Bcfe in the same period of 2004 primarily due to decreased Gulf of Mexico production, partially offset by increased onshore production. Increased development drilling at our Aldwell unit in West Texas contributed to a 63% increase in onshore production to an average of approximately 14.9 Mmcfe per day in the first quarter of 2005 from an average of approximately 9.1 Mmcfe per day in the first quarter of 2004.

In the deepwater Gulf of Mexico, production decreased approximately 31% to an average of approximately 40 Mmcfe per day in the first quarter of 2005 compared to an average of approximately 58 Mmcfe per day in the first quarter of 2004. The decrease was largely due to reduced production at our Black Widow and Pluto fields. Pluto was shut-in in April 2004 pending drilling of the new Mississippi Canyon 674 #3 well and installation of an extension to the existing subsea facilities. Production at Black Widow is undergoing expected declines.

In the Gulf of Mexico shelf, production decreased by approximately 21% to an average of approximately 37 Mmcfe per day in the first quarter of 2005 from an average of approximately 48 Mmcfe per day in the first quarter of 2004. About 6.2 Mmcfe per day of the decrease is attributable to our Ochre field which remains shut-in due to the effects of Hurricane Ivan in September 2004. Production from three new shelf discoveries (Green Pepper, Royal Flush, and Dice) offset normal declines at our other Gulf of Mexico shelf fields.

Hedging activities in the first quarter of 2005 increased our average realized natural gas price received by $0.02 per Mcf and revenues by $0.1 million, compared with an increase of $0.50 per Mcf and revenues of $3.3 million for the same period in 2004. Our hedging activities with respect to crude oil during the first

Table of Contents

quarter of 2005 decreased the average sales price received by $7.96 per barrel and revenues by $3.9 million compared with a decrease of $2.17 per barrel and revenues of $1.4 million for the same period in 2004.

Oil and gas revenues decreased 12% to $54.0 million in the first quarter of 2005 when compared to first quarter 2004 oil and gas revenues of $61.0 million, due to the aforementioned 20% decrease in production, partially offset by a 10% increase in realized prices (including the effects of hedging) to $6.50 per Mcfe in the first quarter of 2005 from $5.91 per Mcfe in the same period in 2004.

Other revenues of $1.9 million in the first quarter of 2005 represent an indemnity payment received from our former stockholder related to the Merger.

Lease operating expenses decreased 15% to $6.2 million in the first quarter of 2005 from $7.2 million in the first quarter of 2004. The reduced costs were primarily attributable to our deep water fields, including Pluto, which was temporarily shut-in in April 2004, partially offset by the addition of new producing wells at our Aldwell unit. On a per unit basis, lease operating expenses were $0.74 per Mcfe in the first quarter of 2005 compared to $0.70 per Mcfe in the first quarter of 2004.

Transportation expenses were $1.0 million or $0.12 per Mcfe in the first quarter of 2005, compared to $1.7 million or $0.17 per Mcfe in the first quarter of 2004. The reduction is primarily attributable to our deep water fields and includes reductions caused by the filing of new and higher transportation allowances with the MMS on two of our deep water fields for purpose of royalty calculation.

Depreciation, depletion, and amortization expense decreased 10% to $15.1 million during the first quarter of 2005 from $16.9 million for the first quarter of 2004 as a result of decreased production of 2.0 Bcfe in the first quarter of 2005 compared to the first quarter 2004, partially offset by an increase in the unit-of-production depreciation, depletion and amortization rate to $1.82 per Mcfe for the first quarter of 2005 from $1.63 per Mcfe for the same period in 2004. The per unit increase was primarily the result of push-down accounting to restate our oil and gas assets to fair value as of March 2, 2004.

General and administrative expenses (G&A), which are net of $1.0 million and $0.7 million of overhead reimbursements received from other working interest owners in the first quarter of 2005 and 2004, respectively, increased 93% to $5.2 million during the first quarter of 2005 compared to $2.7 million in the first quarter of 2004. The increase was primarily due to recognizing $1.3 million in stock compensation expense related to restricted stock granted in the first quarter of 2005 and $2.3 million paid to our former stockholders to terminate a services agreement. In addition, G&A expenses increased by $0.9 million due to a reduction in the amount of G&A capitalized in the first quarter of 2005 compared to the first quarter of 2004. These increases were partially offset by reduced compensation expense of $1.7 million in the first quarter of 2005 compared to the first quarter of 2004 which included merger-related payments under the Company s Long-Term Incentive Plan.

Net interest expense for the first quarter of 2005 increased 138% to $1.3 million from $0.6 million in the first quarter of 2004, primarily due to lower average debt levels in the first quarter of 2004 compared to the first quarter of 2005. In connection with the Merger on March 2, 2004, the Company incurred $135 million in new bank debt and issued a $10 million promissory note to JEDI. For comparison purposes, approximately one month of interest related to such borrowings is reflected in the first quarter of 2004 compared to three months of interest in 2005.

Income before income taxes and change in accounting method decreased to $27.0 million for the first quarter of 2005 compared to $31.9 million for the same period in 2004, attributable primarily to the decrease in oil and gas revenues resulting from the decreased production and increased G&A expenses, both as noted above. Offsetting these factors were the receipt of other income related to the indemnity payment and lower DD&A, lease operating and transportation expenses.

Provision for income taxes decreased to $9.3 million for the first quarter of 2005 from $11.2 million for the first quarter of 2004 as a result of decreased operating income for the three months ended March 31, 2005 compared to the prior period.

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

Net production during 2004 increased to 37.6 Bcfe 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.

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.

Impairment of production equipment held for use 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

Working capital at March 31, 2005 was a negative $27.5 million, excluding restricted cash, current derivative liabilities and related tax effects. Accounts payable and accrued liabilities at March 31, 2005 increased by approximately 17% over levels at December 31, 2004 primarily due to increased current obligations for our Swordfish development project at quarter end. As of December 31, 2004, we had negative working capital of approximately $18.7 million compared to positive working capital of

Table of Contents

$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 32% 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 2005 will approximate $271 million with approximately 53% allocated to development projects, 31% to exploration activities, 13% to acquisitions and the remainder to other items (primarily capitalized overhead and interest). This is an increase of approximately $119 million over our original 2005 budget. The increase is primarily driven by new projects at our King Kong, Yosemite, LaSalle/NW Nansen, Bass Lite, and Capricorn projects. We have also added capital to our budget for anticipated acquisitions of interests in onshore properties in 2005.

With the anticipated increase in capital expenditures, cash flows generated by operations for 2005 will not be sufficient to fund our 2005 capital expenditures. Any requirements for funding that exceed our cash flows will be funded through additional borrowings under our existing revolving credit facility. We currently have a borrowing base of $135 million with approximately $95 million drawn as of June 30, 2005. We have requested our bank group to increase our borrowing base from $135 million to a level sufficient to fund our currently projected capital expenditures.

However, the timing of expenditures (especially regarding deepwater projects) is unpredictable. 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.

Table of Contents

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.

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

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.

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

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.

	Combined	Post-Merger	Pre-Merger		
	Year Ended December 31, 2004	Period from March 3, 2004 to December 31, 2004	Period from January 1, 2004 to March 2, 2004	Year Ended December 31, 2003	Year Ended December 31, 2002

	(unaudited)		
		(in millions)	
Cash flows used in financing activities	$ (64.9)	$ (64.9)	$ (100.0)

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.

Table of Contents

As of March 31, 2005, the Company had the following hedge contracts outstanding:

Fixed Price Swaps	Quantity	Fixed Price	March 31, 2005 Fair Value Gain/(Loss)
			(in millions)
Crude Oil (Bbls)			
April 1 December 31, 2005	412,500	$ 25.34	$ (12.9)
January 1 December 31, 2006	140,160	29.56	(3.6)
Natural Gas (MMBtus)			
April 1 December 31, 2005	5,490,189	5.04	(15.4)
January 1 December 31, 2006	1,827,547	5.53	(4.7)
Total			$ (36.6)

Costless Collars	Quantity	Floor	Cap	March 31, 2005 Fair Value Gain/(Loss)
				(in millions)
Crude Oil (Bbls)				
April 1 December 31, 2005	173,250	$ 35.60	$ 44.77	$ (2.1)
January 1 December 31, 2006	251,850	32.65	41.52	(3.5)
January 1 December 31, 2007	202,575	31.27	39.83	(2.6)
Natural Gas (MMBtus)				
April 1 December 31, 2005	6,545,000	6.01	8.02	(3.3)
January 1 December 31, 2006	7,347,450	5.78	7.85	(5.0)
January 1 December 31, 2007	5,310,750	5.49	7.22	(3.4)
Total				$ (19.9)

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)

Table of Contents

Costless Collars		Quantity	Floor	Cap	December 31, 2004 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 and March 31, 2005, we had no deposits for collateral.

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

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

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.

We have requested our bank group to increase our borrowing base from $135 million to a level sufficient to fund our currently projected capital expenditures.

Table of Contents

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;

- 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, $55.0 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 June 30, 2005, $4 million was still outstanding under the JEDI note.

Table of Contents

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.

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

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.

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.

Table of Contents

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.

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

Table of Contents

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.

Table of Contents

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.