MARINER LP LLC
Form 424B3
November 22, 2006

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Filed pursuant to Rule 424(b)(3)
Registration No. 333-137441

PROSPECTUS

$300,000,000
71/2% Senior Notes due 2013

The Offer to Exchange
$300,000,000 71/2% Senior Notes due 2013
that have been registered under the Securities Act of 1933
for any and all
$300,000,000 71/2% Senior Notes due 2013
expired at 5:00 P.M.,
New York City time, on November 9, 2006.

We offered to exchange an aggregate principal amount of $300,000,000 of registered 71/2% Senior Notes due 2013, which we refer to as the new notes, for any and all of our original unregistered 71/2% Senior Notes due 2013 that were issued in a private offering on April 24, 2006, which we refer to as the old notes. The exchange offer expired at 5:00 p.m., New York City time, on November 9, 2006, which we refer to as the exchange date. Each broker-dealer (other than an affiliate of ours) that receives new notes for its own account in the exchange offer in exchange for securities that were acquired by such broker-dealer as a result of market-making or other trading activities must deliver a prospectus meeting the requirements of the Securities Act of 1933 in connection with any resale of new notes. We have agreed that, for a period of 90 days after the exchange date, we will make the prospectus available to any broker-dealer for use in connection with any such resale.

Terms of the exchange offer:

We exchanged all outstanding old notes that were validly tendered and not withdrawn prior to the expiration of the exchange offer for an equal principal amount of new notes.

The terms of the new notes are substantially identical to those of the old notes, except that the transfer restrictions, registration rights and special interest provisions relating to the old notes do not apply to the new notes.

The ability to withdraw tenders of old notes ceased upon expiration of the exchange offer.

The exchange of new notes for old notes is not a taxable transaction for U.S. federal income tax purposes.

We did not receive any proceeds from the exchange offer.

The new notes are eligible for trading in the Private Offering, Resales and Trading Automatic Linkage (PORTAL) Market. SM We do not intend to apply for a listing of the new notes on any securities exchange or for their inclusion on any automated dealer quotation system.

See Risk Factors beginning on page 18 for a discussion of risks you should consider in connection with the notes.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation

to the contrary is a criminal offense.

We may amend or supplement this prospectus from time to time by filing amendments or supplements as required. You should read this entire prospectus and related documents and any amendments or supplements to this prospectus carefully before making your investment decision.

The date of this prospectus is November 22, 2006.

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THIS PROSPECTUS IS PART OF A REGISTRATION STATEMENT WE FILED WITH THE SECURITIES AND EXCHANGE COMMISSION, OR SEC. IN MAKING YOUR INVESTMENT DECISION, YOU SHOULD RELY ONLY ON THE INFORMATION CONTAINED IN THIS PROSPECTUS, IN THE ACCOMPANYING LETTER OF TRANSMITTAL OR THE INFORMATION TO WHICH WE HAVE REFERRED YOU. WE HAVE NOT AUTHORIZED ANYONE TO PROVIDE YOU WITH ANY OTHER INFORMATION. IF YOU RECEIVE ANY UNAUTHORIZED INFORMATION, YOU MUST NOT RELY ON IT. THIS PROSPECTUS MAY ONLY BE USED WHERE IT IS LEGAL TO EXCHANGE THE OLD NOTES. YOU SHOULD NOT ASSUME THAT THE INFORMATION CONTAINED IN THIS PROSPECTUS IS ACCURATE AS OF ANY DATE OTHER THAN THE DATE ON THE FRONT COVER OF THIS PROSPECTUS.

Until January 8, 2007, all dealers that effect transactions in these securities, whether or not participating in this exchange offer, may be required to deliver a prospectus. This is in addition to the dealers obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Various statements in this prospectus, 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 may, will, 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, liquidity and 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;
- risks arising out of our hedging transactions;
- marketing of oil and natural gas;
- competition in the oil and natural gas industry;
- the impact of weather and the occurrence of natural disasters such as hurricanes, fires, floods and other catastrophic events and natural disasters;
- governmental regulation of the oil and natural gas industry;

environmental liabilities;

developments in oil-producing and natural gas-producing countries;

uninsured or underinsured losses in our oil and natural gas operations;

risks related to our level of indebtedness;

our merger with Forest Energy Resources, including strategic plans, expectations and objectives for future operations, and the realization of expected benefits from the transaction; and

disruption from the merger with Forest Energy Resources making it more difficult to manage Mariner s business.

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WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our SEC filings are available to the public over the Internet at the SEC s web site at www.sec.gov. You also may read and copy any document we file at the SEC s public reference room in Washington, D.C. Please call the SEC at 1-800-SEC-0330 for further information about the public reference room. Reports and other information concerning us can also be inspected at the offices of the New York Stock Exchange, 20 Broad Street, New York, New York 10005. Our common stock is listed and traded on the New York Stock Exchange under the trading symbol ME.

You may request a copy of these filings, which we will provide to you at no cost, by writing or telephoning us at the following address: Mariner Energy, Inc., One Briar Lake Plaza, Suite 2000, 2000 West Sam Houston Parkway South, Houston, Texas 77004. Our phone number is (713) 954-5555. Our website address is www.mariner-energy.com. The information on our website is not a part of this prospectus.

We filed a registration statement on Form S-4 to register with the SEC the new notes issued in exchange for the old notes and guarantees thereof. This prospectus is part of that registration statement. As allowed by the SEC s rules, this prospectus does not contain all of the information you can find in the registration statement or the exhibits to the registration statement. You should note that where we summarize in the prospectus the material terms of any contract, agreement or other document filed as an exhibit to the registration statement, the summary information provided in the prospectus is less complete than the actual contract, agreement or document. You should refer to the exhibits filed to the registration statement for copies of the actual contract, agreement or document.

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PROSPECTUS SUMMARY

This summary highlights information appearing in other sections of this prospectus. It does not contain all of the information you may wish to consider before participating in the exchange offer. We urge you to read this entire prospectus to understand fully the terms of the notes and other considerations that may be important to you in making your decision regarding the exchange offer, including the Risk Factors section beginning on page 18 of this prospectus. As used in this prospectus, unless the context otherwise requires or indicates, references to Mariner, we, our, ours, and us refer to Mariner Energy, Inc. and its subsidiaries collectively. Certain oil and natural gas industry terms used in this prospectus are defined in the Glossary of Oil and Natural Gas Terms beginning on page 165. References to pro forma and on a pro forma basis mean on a pro forma basis, giving effect to our merger with Forest Energy Resources, Inc. which was completed on March 2, 2006, as if this merger had occurred on the applicable date of determination or on the first day of the applicable period. The unaudited pro forma information contained in this prospectus has been derived from and should be read together with the historical consolidated financial statements of Mariner and the statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations. The statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations do not include all of the costs of doing business. The pro forma information is for illustrative purposes only. The financial results may have been different had the Forest Gulf of Mexico operations been an independent company and had the companies always been combined. You should not rely on the pro forma financial information as being the historical results that would have been achieved had the merger occurred in the past or the future financial results that Mariner will achieve after the merger.

Our Company

Mariner Energy, Inc. is an independent oil and gas exploration, development and production company with principal operations in the Gulf of Mexico, both shelf and deepwater, and in West Texas. Our management has significant expertise and a successful operating track record in these areas. In the three-year period ended December 31, 2005, we added approximately 280 Bcfe of proved reserves and produced approximately 100 Bcfe, while deploying approximately $475 million of capital on acquisitions, exploration and development.

Our primary operating strategy is to generate high-quality exploration and development projects, which enables us to add value through the drill bit. Our expertise in project generation also facilitates our participation in high-quality projects generated by other operators. We will also pursue acquisitions of producing assets that have the potential to provide acceptable risk-adjusted rates of return and further reserve additions through exploration, exploitation, and development opportunities. We target a balanced exposure to development, exploitation and exploration opportunities, both offshore and onshore and seek to maintain a moderate risk profile.

On March 2, 2006, we completed a merger transaction with Forest Energy Resources, Inc., which we refer to as Forest Energy Resources. As a result of this merger, we acquired the Gulf of Mexico operations of Forest Oil Corporation (NYSE: FST), which we refer to as the Forest Gulf of Mexico operations. We refer to Forest Oil Corporation as Forest.

As of December 31, 2005, we had 338 Bcfe of estimated proved reserves, of which approximately 62% were natural gas and 38% were oil and condensate, and 50% of which was proved developed. Pro forma for the merger transaction, as of December 31, 2005, we had 644 Bcfe of estimated proved reserves, of which approximately 68% were natural gas and 32% were oil and condensate, and 56% of which was proved developed. Our pro forma production for 2005 was approximately 95 Bcfe, or 260 MMcfe per day on average. During the year ended December 31, 2005, our pro forma EBITDA was approximately $438.6 million, including $25.7 million of non-cash compensation expense related to restricted stock and stock options granted in 2005, but excluding general and administrative expenses of the Forest Gulf of Mexico operations. Our production for the nine months ended September 30, 2006 was approximately 55 Bcfe, or 200 MMcfe per day on average, and pro forma for the merger, 62 Bcfe, or 229 MMcfe per day on average. During the nine months ended September 30, 2006, our EBITDA was approximately $340.7 million, and pro forma for the merger, approximately $391.7 million, in each case, including $9.0 million of non-cash compensation expense related to restricted stock and stock options. We believe the overhead costs associated with the Forest Gulf of Mexico operations in 2006 will be approximately $6.4 million, net of capitalized amounts. See footnote 1 on page 13 for our definition of EBITDA and a reconciliation of net income to EBITDA.

The following table sets forth certain information with respect to our estimated proved reserves, production and acreage by geographic area on a pro forma basis for our merger with Forest Energy Resources as of December 31, 2005. Reserve volumes and values were determined under the method prescribed by the SEC which requires the application of period-end prices and costs held constant throughout the projected reserve life. Proved reserve estimates do not include any value for probable or possible reserves which may exist, nor do they include any value for undeveloped acreage. The proved reserve estimates represent our net revenue interest in our properties. The reserve information for Mariner as of December 31, 2005 is based on estimates made in a reserve report prepared by Ryder Scott Company, L.P., independent petroleum engineers (Ryder Scott). The reserve information as of December 31, 2005 for the Forest Gulf of Mexico operations is based on estimates made by internal staff engineers of Forest, which estimates were audited by Ryder Scott. Accordingly, the pro forma reserve information presented below includes both reserves that were estimated by Ryder Scott and reserves that were estimated by internal staff engineers of Forest and audited by Ryder Scott. This information is presented on a pro forma basis, giving effect to our merger with Forest Energy Resources as though it had been consummated on December 31, 2005. We consummated the merger on March 2, 2006.

	Pro Forma Estimated Proved Reserve Quantities				Pro Forma Production for Year Ended December 31, 2005
Geographic Area	Oil (MMbbls)	Natural Gas (Bcf)	Total (Bcfe)	Pro Forma Total Net Acreage	(Natural Gas Equivalent (Bcfe))
West Texas	16.7	105.5	205.5	31,199	6.6
Gulf of Mexico Deepwater(1)	4.8	95.7	124.5	241,320	14.0
Gulf of Mexico Shelf(2)	12.7	237.6	313.7	652,086	74.3
Total	34.2	438.8	643.7	924,605	94.9
Proved Developed Reserves	18.4	252.1	362.3		

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

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

Our Strategy and Our Competitive Strengths

Our Strategy

The principal elements of our operating strategy include:

Generating and pursuing high-quality prospects. We expect to continue our strategy of growth through the drill bit by continuing to identify and develop high-impact shelf, deep shelf and deepwater projects in the Gulf of Mexico. Our technical team has significant expertise in, and a successful track record of achieving growth by, generating prospects internally and selectively participating in prospects generated by other operators. We believe the Gulf of Mexico is an area that offers substantial growth opportunities, and our acquisition of the Forest Gulf of Mexico operations has more than doubled our existing undeveloped acreage position in the Gulf, providing numerous additional exploration, exploitation and development opportunities.

Maintaining a moderate risk profile. We seek to manage our risk profile by targeting a balanced exposure to development, exploitation and exploration opportunities. For example, we intend to continue

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to develop and seek to expand our West Texas asset base, which contributes stable cash flows and long-lived reserves to our portfolio as a counterbalance to our high-impact, high-production Gulf of Mexico assets. We also seek to mitigate and diversify our risk in drilling projects by selling partial or entire interests in projects to industry partners or by entering into arrangements with industry partners in which they agree to pay a disproportionate share of drilling costs and compensate us for expenses incurred in prospect generation. We also enter into trades or farm-in transactions whereby we acquire interests in third-party generated prospects, thereby gaining exposure to a greater number of prospects. We expect more opportunities to participate in these prospects in the future as a result of our larger scale and increased cash flow from the Forest Gulf of Mexico operations.

Pursuing opportunistic acquisitions. Until 2005, we grew our reserves primarily through the drill bit. In 2005 we added significant proved reserves primarily through acquisitions in West Texas and subsequently in March 2006, through the acquisition of the Forest Gulf of Mexico operations. As part of our growth strategy, we will seek to continue to acquire producing assets that have the potential to provide acceptable risk-adjusted rates of return and further reserve additions through exploration, exploitation and development opportunities.

Our Competitive Strengths

We believe our core resources and strengths include:

Our high-quality assets with geographic and geological diversity. Our assets and operations are diversified among the Gulf of Mexico shelf, deep shelf and deepwater, and West Texas. Our asset portfolio provides a balanced exposure to long-lived West Texas reserves, Gulf of Mexico shelf growth opportunities and high-impact deepwater prospects.

Our large inventory of prospects. We believe we have significant potential for growth through the development of our existing asset base. The acquisition of the Forest Gulf of Mexico operations more than doubled our existing undeveloped acreage position in the Gulf of Mexico to approximately 450,000 net acres and increased our total net leasehold acreage offshore to nearly one million acres, providing numerous exploration, exploitation and development opportunities. As of September 30, 2006, we have an inventory of approximately 890 drilling locations in West Texas, which we believe would require approximately six years to drill at our current rate. These include approximately 430 locations pertaining to 98 Bcfe of estimated net proved undeveloped reserves and approximately 460 other locations.

Our successful track record of finding and developing oil and gas reserves. We have demonstrated our expertise in finding and developing additional proved reserves. In the three-year period ended December 31, 2005, we deployed approximately $475 million of capital on acquisitions, exploration and development, while adding approximately 280 Bcfe of proved reserves and producing approximately 100 Bcfe.

Our depth of operating experience. Our team of 41 geoscientists, engineers, geologists and other technical professionals and landmen as of September 30, 2006 average more than 22 years of experience in the exploration and production business (including extensive experience in the Gulf of Mexico), much of it with major oil companies. The addition of experienced Forest personnel to Mariner s team of technical professionals has further enhanced our ability to generate and maintain an inventory of high-quality drillable prospects and to further develop and exploit our assets. Mariner s technical team has also proven to be an effective and efficient operator in West Texas, as evidenced by our successful production and reserve growth there in recent years.

Our technology and production techniques. Our team of geoscientists currently has access to seismic data from multiple, recent vintage 3-D seismic databases covering more than 7,000 blocks in the Gulf of Mexico that we intend to continue to use to develop prospects on acreage being evaluated for leasing and to develop and further refine prospects on our expanded acreage position. We also have extensive experience and a successful track record in the use of subsea tieback technology to connect offshore wells to existing production facilities. This technology facilitates production from offshore properties without the necessity of fabrication and installation of platforms and top-side facilities that typically are more costly and require longer lead times. We believe the use of subsea tiebacks in appropriate projects enables us to bring production online more quickly, makes target prospects more profitable and allows us to exploit reserves that may otherwise be considered non-commercial because of the high cost of infrastructure. In the Gulf of Mexico, in the three years ended December 31, 2005, we were directly involved in 14 projects (five of which we operated) utilizing subsea tieback systems in water depths ranging from 475 feet to more than 6,700 feet. As of September 30, 2006, we had 18 subsea wells in water depths ranging from 450 feet to more than 4,700 feet. These wells were tied back to 13 host production facilities for production processing. An additional nine wells in water depths ranging from 465 feet to more than 6,800 feet were then under development for tieback to five additional host production facilities.

Recent Developments

Forest Gulf of Mexico Merger

On March 2, 2006, we completed a merger transaction with Forest Energy Resources. Prior to the consummation of the merger, Forest transferred and contributed the assets and certain liabilities associated with its Gulf of Mexico operations to Forest Energy Resources. Immediately prior to the merger, Forest distributed all of the outstanding shares of Forest Energy Resources to Forest shareholders on a pro rata basis. Forest Energy Resources then merged with a newly-formed subsidiary of Mariner, became a new wholly-owned subsidiary of Mariner and changed its name to Mariner Energy Resources, Inc. Immediately following the merger, approximately 59% of Mariner common stock was held by shareholders of Forest and approximately 41% of Mariner common stock was held by the pre-merger stockholders of Mariner.

Forest Energy Resources had approximately 306 Bcfe of estimated proved reserves as of December 31, 2005, of which approximately 76% were natural gas, and 24% were oil and condensate. The reserves and operations acquired from Forest are concentrated in the shelf and deep shelf of the Gulf of Mexico and represent a significant addition to Mariner s asset portfolio in those areas of operation.

We believe our acquisition of the Forest Gulf of Mexico operations and the scale they bring to our business has further moderated our risk profile, provided many exploration, exploitation and development opportunities, enhanced our ability to participate in prospects generated by other operators, and added a significant cash flow generating resource that has improved our ability to compete effectively in the Gulf of Mexico and fund exploration activities and acquisitions. We believe we are well-positioned to optimize the Forest Energy Resources assets through aggressive and timely exploitation.

West Cameron Acquisition

In August 2006, we acquired the interest of BP Exploration and Production Inc., which we refer to as BP , in West Cameron Block 110 and the southeast quarter of West Cameron Block 111 in the Gulf of Mexico. The interest was acquired by our subsidiary, Mariner Energy Resources, Inc., exercising its preferential right to purchase. BP retained its interest in depths below 15,000 feet. In the Forest merger, we acquired Forest Energy Resources 37.5% interest in the properties. As a result of the August 2006 acquisition, Mariner Energy Resources, Inc. now owns 100% of the working interest, exclusive of the deep rights retained by BP, and Mariner Energy, Inc. became operator of the interests owned by its subsidiary. The acquisition cost, net of preliminary purchase price adjustments, was approximately $70.9 million, which was financed by borrowing under our senior secured credit facility. A $10.4 million letter of credit under our senior secured credit facility also was issued in favor of BP to secure plugging and abandonment obligations. The acquisition adds proved reserves estimated by us to be 20 Bcfe as of August 1, 2006. Production associated with the acquired interest was approximately 11 MMcfe/day during July 2006.

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Material Gulf of Mexico Discovery

In October 2006, we announced that we made a material conventional shelf discovery in the High Island 116 #5ST1 well, drilled to a total measured depth of 14,683 feet / 13,150 feet true vertical depth. The well encountered approximately 540 feet of net true vertical depth pay in thirteen sands. We anticipate completion and initial production in the fourth quarter of 2006. High Island 116 is part of the Forest Gulf of Mexico operations we acquired in March 2006. We have a 100% working interest and an approximate 72% net revenue interest in the well.

Effects of the 2005 Hurricane Season

In 2005, our operations were adversely affected by one of the most active and severe hurricane seasons in recorded history, resulting in shut-in production and startup delays. We estimate that as of September 30, 2006, approximately 12 MMcfe per day of production remained shut-in and approximately 33 MMcfe per day of production had recommenced since June 30, 2006. The four deepwater projects that experienced startup delays have recommenced production. As a result of ongoing repairs to pipelines, facilities, terminals and host facilities, we expect most of the remaining shut-in production to recommence by the end of 2006 and the balance in 2007, except that an immaterial amount of production is not expected to recommence.

We estimate the costs to repair damage caused by the hurricanes to our platforms and facilities will be approximately $85 million. However, until we are able to complete all the repair work this estimate is subject to significant variance. For the insurance period covering the 2005 hurricane activity, we carried a $3 million annual deductible and a $0.5 million single occurrence deductible for the Mariner assets. Insurance covering the Forest Gulf of Mexico properties carried a $5 million deductible for each occurrence. Until the repairs are completed and we submit costs to our insurance underwriters for review, the full extent of our insurance recoveries and the resulting net cost to us for Hurricanes Katrina and Rita will be unknown. However, we expect the total costs not covered by the combined insurance policies to be less than $15 million.

Corporate Information

We were incorporated in August 1983 as a Delaware corporation. We have three subsidiaries, Mariner Energy Resources, Inc., a Delaware corporation, Mariner LP LLC, a Delaware limited liability company, and Mariner Energy Texas LP, a Delaware limited partnership. Our principal executive office is located at One Briar Lake Plaza, Suite 2000, 2000 West Sam Houston Parkway South, Houston, Texas 77042. Our telephone number is (713) 954-5500.

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The Exchange Offer

On April 24, 2006, we completed an unregistered offering of the old notes. As part of that offering, we entered into a registration rights agreement with the initial purchasers of the old notes in which we agreed, among other things, to use commercially reasonable efforts to complete the exchange offer which expired on November 9, 2006. Each broker-dealer (other than an affiliate of ours) that receives new notes for its own account in the exchange offer in exchange for securities that were acquired by such broker-dealer as a result of market-making or other trading activities must deliver a prospectus meeting the requirements of the Securities Act in connection with any resale of new notes. In the registration rights agreement, we also agreed that for a period of 90 days after the exchange date, we will make this prospectus available to any broker-dealer for use in connection with any such resale. We refer to the old notes and the new notes (separately or collectively, as the context indicates) as the notes. The following is a brief summary of the exchange offer that expired on November 9, 2006. Please also see Exchange Offer.

Old Notes	71/2% Senior Notes due April 15, 2013, which were issued on April 24, 2006.
New Notes	71/2% Senior Notes due April 15, 2013. The terms of the new notes are substantially identical to those terms of the old notes, except that the transfer restrictions, registration rights and special interest provisions relating to the old notes do not apply to the new notes.
Exchange Offer	We offered to exchange $300.0 million principal amount of our new notes that have been registered under the Securities Act for an equal amount of our old notes to satisfy our obligations under the registration rights agreement. The new notes evidence the same debt as the old notes and are issued under and entitled to the benefits of the same indenture that governs the old notes. Holders of the old notes do not have any appraisal or dissenter s rights in connection with the exchange offer. Because the new notes are registered, the new notes will not be subject to transfer restrictions, and holders of old notes that have tendered and had their old notes accepted in the exchange offer have no registration rights.
Expiration Date	The exchange offer expired at 5:00 P.M., New York City time, on November 9, 2006. The ability to withdraw tenders of old notes pursuant to the exchange offer ceased upon expiration of the exchange offer.

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Description of Senior Notes

The terms of the new notes and those of the outstanding old notes are substantially identical, except that the transfer restrictions and registration rights relating to the old notes do not apply to the new notes. As a result, the new notes will not bear legends restricting their transfer and will not have the benefit of the registration rights and related special interest provisions contained in the old notes. The new notes represent the same debt as the old notes for which they are being exchanged. Both the old notes and the new notes are governed by the same indenture.

Issuer	Mariner Energy, Inc.
Notes Offered	$300,000,000 principal amount of its 71/2% Senior Notes due 2013.
Maturity Date	April 15, 2013.
Interest Rate	71/2% per year (calculated using a 360-day year).
Interest Payment Dates	Each April 15 and October 15, beginning October 15, 2006.
Ranking	The notes are our general unsecured senior obligations. Accordingly, they rank: effectively subordinate to all of our existing and future secured indebtedness, including indebtedness under our credit facility, to the extent of the collateral securing such indebtedness; effectively subordinate to all existing and future indebtedness and other liabilities of any non-guarantor subsidiaries (other than indebtedness and liabilities owed to us); *pari passu* in right of payment to all of our existing and future senior unsecured indebtedness; and senior in right of payment to any future subordinated indebtedness. As of September 30, 2006, we had total indebtedness of approximately $614 million, $300 million of which was the notes, and approximately $314 million of which was secured indebtedness to which the notes effectively were subordinated as to the value of the collateral. We also then had three letters of credit outstanding for $40.0 million, $10.4 million and $4.2 million, each of which effectively was senior to the notes to the extent of the collateral securing such indebtedness.
Subsidiary Guarantees	The notes are jointly and severally guaranteed on a senior unsecured basis by our existing and future domestic subsidiaries. In the future, the guarantees may be released or terminated under certain circumstances. Each subsidiary guarantee ranks: effectively subordinate to all existing and future secured indebtedness of the guarantor subsidiary, including its guarantee of indebtedness under our

credit facility, to the extent of the collateral securing such indebtedness;

pari passu in right of payment to all existing and future senior unsecured indebtedness of the guarantor subsidiary; and

senior in right of payment to any future subordinated indebtedness of the guarantor subsidiary.

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	As of September 30, 2006, the guarantor subsidiary Mariner Energy Resources, Inc. had approximately $176.2 million of unsecured indebtedness outstanding under an intercompany note payable to us. The other two guarantor subsidiaries were guarantors but not indebted under our senior secured credit facility and had no other indebtedness outstanding.
Optional Redemption	At any time prior to April 15, 2009, we may redeem up to 35% of each of the notes with the net cash proceeds of certain equity offerings at the redemption prices set forth under Description of Senior Notes Optional Redemption, if at least 65% of the aggregate principal amount of the notes issued under the indenture remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. At any time prior to April 15, 2010, we may redeem the notes, in whole or in part, at a make whole redemption price set forth under Description of Senior Notes Optional Redemption. On and after April 15, 2010, we may redeem the notes, in whole or in part, at the redemption prices set forth under Description of Senior Notes Optional Redemption.
Change of Control Triggering Event	If a Change of Control Triggering Event occurs, we must offer to repurchase the notes at the redemption price set forth under Description of Senior Notes Repurchase at the Option of Holders Change of Control.
Certain Covenants	The indenture governing the notes contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: make investments; incur additional indebtedness or issue preferred stock; create certain liens; sell assets; enter into agreements that restrict dividends or other payments from our subsidiaries to us; consolidate, merge or transfer all or substantially all of the assets of our company; engage in transactions with affiliates; pay dividends or make other distributions on capital stock or subordinated indebtedness; and create unrestricted subsidiaries.

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	These covenants are subject to important exceptions and qualifications. In addition, substantially all of the covenants will terminate before the notes mature if one of two specified ratings agencies assigns the notes an investment grade rating in the future and no events of default exist under the indentures. Any covenants that cease to apply to us as a result of achieving an investment grade rating will not be restored, even if the credit rating assigned to the notes later falls below an investment grade rating. See Description of Senior Notes Certain Covenants.
Absence of Established Market for the Notes	The new notes are generally freely transferable but are also new securities for which there will not initially be a market. Accordingly, we cannot assure you as to the development or liquidity of any market for the new notes. The notes will be eligible for trading in the PORTAL^{sm} Market. We do not intend to apply for a listing of the new notes on any securities exchange or for the inclusion on any automated dealer quotation system.
Use of Proceeds	We will not receive any proceeds from the exchange offer.

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Summary Historical Financial Information

The following table shows Mariner s summary historical consolidated financial data as of and for the nine months ended September 30, 2006 and September 30, 2005, the year ended December 31, 2005, the period from January 1, 2004 through March 2, 2004, the period from March 3, 2004 through December 31, 2004, and each of the three years ended December 31, 2003. The summary historical consolidated financial data for the year ended December 31, 2005, the period from January 1, 2004 through March 2, 2004, the period from March 3, 2004 through December 31, 2004, and each of the three years ended December 31, 2003 are derived from Mariner s audited financial statements included herein, and the historical consolidated financial data as of and for the two years ended December 31, 2002 are derived from Mariner s audited financial statements that are not included herein. The summary historical consolidated financial data for the nine months ended September 30, 2006 and the nine months ended September 30, 2005 has been derived from Mariner s unaudited financial statements. You should read the following data in connection with 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 with Forest Energy Resources. Mariner s historical results are not necessarily indicative of results to be expected in future periods.

The merger between a subsidiary of Mariner and Forest Energy Resources was consummated on March 2, 2006. Accordingly, the financial information as of September 30, 2006 below includes the Forest Gulf of Mexico operations as of and after March 2, 2006.

On March 2, 2004, Mariner s former indirect parent, Mariner Energy LLC, merged with MEI Acquisitions, LLC, an affiliate of the private equity funds, Carlyle/Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC. The financial information contained herein is presented in the style of Post-2004 Merger activity (for the March 3, 2004 through December 31, 2004 period, the year ended December 31, 2005 and the nine months ended September 30, 2006 and September 30, 2005) and Pre-2004 Merger activity (for all periods prior to March 2, 2004) 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.

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	Post-2004 Merger					Pre-2004 Merger		
	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005	Year Ended December 31, 2005	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004	Year Ended December 31, 2003	Year Ended December 31, 2002	Year Ended December 31, 2001
	(In millions, except per share data)							
Statement of Operations Data:								
Total revenues(1)	$ 438.4	$ 151.2	$ 199.7	$ 174.4	$ 39.8	$ 142.5	$ 158.2	$ 155.0
Lease operating expenses	62.9	17.7	24.9	19.3	3.5	23.2	25.2	19.2
Severance and ad valorem taxes	5.7	2.5	5.0	2.1	0.6	1.5	0.9	0.9
Transportation expenses	4.0	1.7	2.3	1.9	1.1	6.3	10.5	12.0
Depreciation, depletion and amortization	192.2	43.4	59.4	54.3	10.6	48.3	70.8	63.5
Impairment of production equipment held for use		0.5	1.8	1.0				
Derivative settlement						3.2		
Impairment of Enron related receivables							3.2	29.5
General and administrative expenses	25.1	26.7	37.1	7.6	1.1	8.1	7.7	9.3
Operating income	148.5	58.7	69.2	88.2	22.9	51.9	39.9	20.6
Interest income	0.5	0.7	0.8	0.2	0.1	0.8	0.4	0.7
Interest expense	(26.4)	(5.4)	(8.2)	(6.0)		(7.0)	(10.3)	(8.9)
Income before income taxes	122.6	54.0	61.8	82.4	23.0	45.7	30.0	12.4
Provision for income taxes	(44.4)	(18.4)	(21.3)	(28.8)	(8.1)	(9.4)		
Income before cumulative effect of change in accounting method net of tax effects	$ 78.2	$ 35.6	40.5	53.6	14.9	36.3	30.0	12.4
Income before cumulative effect per common share								
Basic	$ 1.07	$ 1.10	1.24	1.80	0.50	1.22	1.01	0.42

Diluted	1.06	1.07	1.20	1.80	0.50	1.22	1.01	0.42
Cumulative effect of changes in accounting method						1.9		
Net income	$ 78.2	$ 35.6	$ 40.5	$ 53.6	$ 14.9	$ 38.2	$ 30.0	$ 12.4
Net income per common share								
Basic	$ 1.07	$ 1.10	$ 1.24	$ 1.80	$ 0.50	$ 1.29	$ 1.01	$ 0.42
Diluted	1.06	1.07	1.20	1.80	0.50	1.29	1.01	0.42
Capital Expenditure and Disposal Data:								
Exploration, including leasehold/seismic	169.1	23.6	$ 60.9	$ 40.4	$ 7.5	$ 31.6	$ 40.4	$ 66.3
Development and other	347.9	106.8	191.8	93.2	7.8	51.7	65.7	98.2
Proceeds from property conveyances	(2.0)					(121.6)	(52.3)	(90.5)
Total capital expenditures net of proceeds from property conveyances	515.0	130.4	$ 252.7	$ 133.6	$ 15.3	$ (38.3)	$ 53.8	$ 74.0

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(1) Includes effects of hedging.

	Post-2004 Merger				Pre-2004 Merger		
	September 30,		December 31,	December 31,	December 31,		
	2006	2005	2005	2004	2003	2002	2001
	(In millions)						
Balance Sheet Data(1)							
Property and equipment, net, full cost method	$ 2,061.9	$ 393.3	$ 515.9	$ 303.8	$ 207.9	$ 287.6	$ 290.6
Total assets	2,700.7	502.2	665.5	376.0	312.1	360.2	363.9
Long-term debt, less current maturities	614.0	79.0	156.0	115.0		99.8	99.8
Stockholders equity	1,267.1	178.6	213.3	133.9	218.2	170.1	180.1
Working capital (deficit)(2)	(75.3)	(30.2)	(46.4)	(18.7)	38.3	(24.4)	(19.6)
Other Financial Data							
Ratio of earnings to fixed charges(3)	5.43	10.23	7.88	17.17	6.83	3.56	1.82

(1) Balance sheet data as of September 30, 2006 reflects consolidation of the assets of the Forest Gulf of Mexico operations effective March 2, 2006. Balance sheet data as of December 31, 2004 reflects purchase accounting adjustments to oil and gas properties, total assets and stockholders equity resulting from the acquisition of our former indirect parent on March 2, 2004.

(2) Working capital (deficit) excludes current derivative assets and liabilities, deferred tax assets and restricted cash.

(3) For the purposes of determining the ratio of earnings to fixed charges, earnings consist of income before taxes, plus fixed charges, less capitalized interest, and fixed charges consist of interest expense (net of capitalized interest), plus capitalized interest, plus amortized discounts related to indebtedness.

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	Post-2004 Merger					Pre-2004 Merger		
	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005	Year Ended December 31, 2005	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004	Year Ended December 31, 2003	Year Ended December 31, 2002	Year Ended December 31, 2001
				(In millions)				
Other Financial Data:								
EBITDA(1)	$ 340.7	$ 102.7	$ 130.4	$ 143.5	$ 33.4	$ 100.3	$ 113.9	$ 113.6
Net cash provided by operating activities	172.8	135.4	165.4	135.2	20.3	88.9	60.3	113.5
Net cash (used) provided by investing activities	(423.5)	(142.1)	(247.8)	(133.0)	(15.3)	52.9	(53.8)	(74.0)
Net cash (used) provided by financing activities	251.0	8.7	84.4	64.9		(100.0)		(30.0)
Reconciliation of Non-GAAP Measures:								
EBITDA(1)	$ 340.7	$ 102.7	$ 130.4	$ 143.5	$ 33.4	$ 100.3	$ 113.9	$ 113.6
Changes in working capital	(158.9)	25.1	20.0	6.2	(13.2)	7.2	(20.4)	7.5
Non-cash hedge gain/(loss)(2)	8.2	(3.6)	(4.5)	(7.9)		(2.0)	(23.2)	
Amortization/other	(0.3)	0.9	1.2	0.8			(0.1)	0.6
Stock compensation expense	9.0	17.6	25.7					
Net interest expense	(25.9)	(4.7)	(7.4)	(5.8)	0.1	(6.2)	(9.9)	(8.2)
Income tax expense		(2.6)		(1.6)		(10.4)		
Net cash provided by operating activities	$ 172.8	$ 135.4	$ 165.4	$ 135.2	$ 20.3	$ 88.9	$ 60.3	$ 113.5

(1) EBITDA means earnings before interest, income taxes, depreciation, depletion and amortization and impairments. For the nine months ended September 30, 2006 and 2005, EBITDA includes $9.0 million and $17.6 million, respectively, in non-cash compensation expense related to restricted stock and stock options. For the year ended December 31, 2005, EBITDA includes $25.7 million in non-cash compensation expense related to restricted stock and stock options granted in 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

performance presented in accordance with generally accepted accounting principles or as a measure of a company s profitability or liquidity.

(2) 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 dedesignation 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. 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. The value at the time of the merger and included in AOCI has reversed out of AOCI and into earnings as the original corresponding production, as hedged by the contracts, is produced. We have designated subsequent hedge contracts as cash flow hedges with gains and losses resulting from the transactions recorded at market value in AOCI, as appropriate, until recognized as operating income in our Statement of Operations as the physical production hedged by the contracts is delivered.

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Summary Selected Unaudited Pro Forma Combined Condensed Financial Information

The merger between a subsidiary of Mariner and Forest Energy Resources was consummated on March 2, 2006. Accordingly, actual balance sheet information of the combined company as of September 30, 2006 is included elsewhere in this prospectus.

The following unaudited pro forma combined condensed operating results for the nine months ended September 30, 2006 and the year ended December 31, 2005 give effect to the merger as if it had occurred on January 1, 2005. This unaudited pro forma combined condensed financial information is based on the historical financial statements of Mariner and the historical statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations, all of which are included in this prospectus, and the estimates and assumptions set forth in the notes to the Unaudited Pro Forma Combined Condensed Financial Information beginning on page 36.

The unaudited pro forma combined condensed financial information is for illustrative purposes only. The financial results may have been different had the Forest Gulf of Mexico operations been an independent company and had the companies always been combined. You should not rely on the unaudited pro forma combined condensed financial information as being indicative of the historical results that would have been achieved had the merger occurred in the past or the future financial results that Mariner will achieve after the merger.

	Nine Months Ended September 30, 2006	Year Ended December 31, 2005
	(In millions, except earnings per share and share data)	
OPERATING RESULTS:		
Revenues	$ 505.9	$ 592.0
Net income	92.6	58.0
Earnings per share		
Basic	$ 1.09	$ 0.70
Diluted	$ 1.09	$ 0.69
Weighted average shares outstanding		
Basic	84,770,289	83,304,592
Diluted	85,245,547	84,454,427

Summary Reserve and Operating Data

The following tables present certain information with respect to our estimated proved oil and natural gas reserves at year end and operating data for the periods presented. The 2005 information is also presented on a pro forma basis, giving effect to our merger with Forest Energy Resources as though it had been consummated on January 1, 2005. We consummated the merger on March 2, 2006.

Estimated Proved Reserves

The reserve information in the table below for Mariner is based on estimates made in reserve reports prepared by Ryder Scott. The reserve information as of December 31, 2005 for the Forest Gulf of Mexico operations is based on estimates made by internal staff engineers at Forest, which estimates were audited by Ryder Scott. Accordingly, the pro forma reserve information presented below includes both reserves that were estimated by Ryder Scott and reserves that were estimated by internal staff engineers at Forest and audited by Ryder Scott.

	Pro Forma Year Ended December 31, 2005	As of the Year Ended December 31,		
		2005	2004	2003
Estimated proved oil and natural gas reserves:				
Natural gas reserves (Bcf)	438.8	207.7	151.9	127.6
Oil (MMbbls)	34.1	21.6	14.3	13.1
Total proved oil and natural gas reserves (Bcfe)	643.7	337.6	237.5	206.1
Total proved developed reserves (Bcfe)	362.3	167.4	109.4	96.6
PV10 value ($ in millions):				
Proved developed reserves	$ 2,023.4	$ 849.6	$ 335.4	$ 314.6
Proved undeveloped reserves	1,028.4	432.2	332.6	218.9
Total PV10 value	3,051.8	1,281.8	668.0	533.5
Standardized measure	2,201.7	906.6	494.4	418.2
Prices used in calculating end of period proved reserve measures (excluding effects of hedging)(1):				
Natural gas ($/MMBtu)	$ 10.05	$ 10.05	$ 6.15	$ 5.96
Oil ($/bbl)	61.04	61.04	43.45	32.52

(1) Our PV10 values have been calculated using NYMEX prices at the end of the relevant period, as adjusted for our price differentials. Please read Note 11 to the audited Mariner financial statements contained in this prospectus.

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Operating Data

The following table presents certain information with respect to our production and operating data for the periods presented. Information for the nine months ended September 30, 2006 and the year ended December 31, 2005 also is presented on a pro forma basis, giving effect to our merger with Forest Energy Resources as though it had been consummated on January 1, 2005. The merger was consummated on March 2, 2006.

	Pro Forma		Nine Months	Year Ended December 31,		
	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Ended September 30, 2006	2005	2004	2003
Production:						
Natural gas (Bcf)	45.6	67.5	39.3	18.4	23.8	23.8
Oil (Mbbls)	2.8	4.6	2.5	1.8	2.3	1.6
Total natural gas equivalent (Bcfe)	62.4	94.9	54.5	29.1	37.6	33.4
Average daily natural gas equivalent (MMcfe)	228.5	260.0	200.0	79.7	103.0	91.5
Average realized sales price per unit (excluding the effects of hedging):						
Natural gas ($/Mcf)	$ 7.25	$ 8.04	$ 7.05	$ 8.33	$ 6.12	$ 5.43
Oil ($/bbl)	61.23	48.86	62.13	51.66	38.52	26.85
Total natural gas equivalent ($/Mcfe)	8.05	8.07	7.94	8.43	6.23	5.15
Average realized sales price per unit (including the effects of hedging):						
Natural gas ($/Mcf)	$ 7.42	$ 6.40	$ 7.25	$ 6.66	$ 5.80	$ 4.40
Oil ($/bbl)	58.95	34.18	59.58	41.23	33.17	23.74
Total natural gas equivalent ($/Mcfe)	8.07	6.20	8.00	6.74	5.70	4.27
Expenses ($/Mcfe):						
Lease operating expenses	$ 1.26	$ 1.04	$ 1.15	$ 0.86	$ 0.61	$ 0.69
Severance and ad valorem taxes	0.10	0.13	0.10	0.17	0.07	0.05
Transportation	0.07	0.06	0.07	0.08	0.08	0.19
General and administrative, net(1)			0.46	1.27	0.23	0.24
Depreciation, depletion and amortization (excluding impairments)(2)	3.51	3.47	3.53	2.04	1.73	1.45

(1) Net of overhead reimbursements received from other working interest owners and amounts capitalized under the full cost accounting method. Includes non-cash stock compensation expense of $9.0 million for the nine months ended September 30, 2006 and $17.6 million in 2005. General and administrative expenses, net of capitalized amounts, are not included in pro forma 2005 because accounts of such costs were not historically maintained for the Forest Gulf of Mexico operations as a separate business unit. We

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believe the overhead costs associated with the Forest Gulf of Mexico operations in 2006 will approximate $6.4 million, net of capitalized amounts.

(2) Pro forma depreciation, depletion and amortization gives effect to the acquisition of the Forest Gulf of Mexico operations and a preliminary estimate of their step-up in value basis the unit of production method under the full cost method of accounting.

RISK FACTORS

You should consider carefully the following risks, as well as the other information set forth in this prospectus, before deciding to participate in the exchange offer. Any of the following risks could materially adversely affect our business, financial condition or results of operations, which in turn could adversely affect our ability to pay the notes. In such case, you may lose all or part of your original investment.

Risks Related to the Exchange Offer

If you do not properly tender your old notes, you will continue to hold unregistered outstanding notes and your ability to transfer those notes will be adversely affected.

If you do not exchange your old notes for new notes in the exchange offer, you will continue to be subject to the restrictions on transfer of your old notes described in the legend on the certificates representing your old notes. In general, you may only offer or sell the old notes if they are registered under the Securities Act and applicable state securities laws or offered and sold under an exemption from those requirements. We do not plan to register any sale of the old notes under the Securities Act unless required to do so under the limited circumstances set forth in the registration rights agreement. In addition, the issuance of the new notes may adversely affect the trading market for untendered, or tendered but unaccepted, old notes. For further information regarding the consequences of not tendering your old notes in the exchange offer, see The Exchange Offer Consequences of Failure to Exchange and Material United States Federal Income Tax Considerations.

We will only issue new notes in exchange for old notes that you timely and properly tender. Therefore, you should allow sufficient time to ensure timely delivery of the old notes and you should carefully follow the instructions on how to tender your old notes. Neither we nor the exchange agent is required to tell you of any defects or irregularities with respect to your tender of old notes. See The Exchange Offer Procedures for Tendering Old Notes and Description of Senior Notes.

You may find it difficult to sell your new notes.

Because there is no public market for the new notes, you may not be able to resell them. The new notes will be registered under the Securities Act but will constitute a new issue of securities with no established trading market. An active market may not develop for the new notes and any trading market that does develop may not be liquid. We do not intend to apply to list the new notes for trading on any securities exchange or to arrange for quotation on any automated dealer quotation system. The trading market for the new notes may be adversely affected by:

- changes in the overall market for non-investment grade securities;
- changes in our financial performance or prospects;
- the prospects for companies in our industry generally;
- the number of holders of the new notes;
- the interest of securities dealers in making a market for the new notes; and
- prevailing interest rates and general economic conditions.

Historically, the market for non-investment grade debt has been subject to substantial volatility in prices. The market for the new notes, if any, may be subject to similar volatility. Prospective investors in the new notes should be aware that they may be required to bear the financial risks of such investment for an indefinite period of time.

Some holders who exchange their old notes may be deemed to be underwriters.

If you exchange your old notes in the exchange offer for the purpose of participating in a distribution of the new notes, you may be deemed to have received restricted securities and, if so, will be required to comply

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with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction. See The Exchange Offer Resale of the New Notes; Plan of Distribution.

Risks Relating to the Oil and Natural Gas Industry and 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. Oil and natural gas prices are currently at or near historical highs and may fluctuate and decline significantly in the near future. Prices for oil and natural gas fluctuate 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 62% of our estimated proved reserves (68% on a pro forma basis) as of December 31, 2005 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 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. 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, 2005, 50% of our estimated proved reserves were proved undeveloped (44% on a pro forma basis).

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 Estimated Proved Reserves for information about our oil and gas reserves.

In estimating future net revenues from proved reserves, we assume that future prices and costs are fixed and apply a fixed discount factor. If any such assumption or the discount factor is materially inaccurate, our revenues, profitability and cash flow could be materially less than our estimates.

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 Minerals Management Service, or 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, and Business Legal Proceedings. 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.

If oil and natural gas prices decrease, we may be required to write-down the carrying value and/or the estimates of total reserves of our oil and natural gas properties.

Accounting rules applicable to us require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write-down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. We may incur non-cash charges in the future, which could have a material adverse effect on our results of operations in the period taken. We may also reduce our estimates of the reserves that may be economically recovered, which could have the effect of reducing the value of our reserves.

We need to replace our reserves at a faster rate than companies whose reserves have longer production periods. Our failure to replace our reserves would result in decreasing reserves and production over time.

Unless we conduct successful exploration and development activities or acquire properties containing proven reserves, our proved reserves will decline as reserves are depleted. Producing oil and natural gas reserves are generally characterized by declining production rates that vary depending on reservoir characteristics and other factors. High production rates generally result in recovery of a relatively higher percentage of reserves from properties during the initial few years of production. A significant portion of our current operations are conducted in the Gulf of Mexico, especially since our merger with Forest Energy Resources. Production from reserves in the Gulf of Mexico generally declines more rapidly than reserves from reservoirs in other producing regions. As a result, our need to replace reserves from new investments is relatively greater than those of producers who produce their reserves over a longer time period, such as those

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producers whose reserves are located in areas where the rate of reserve production is lower. If we are not able to find, develop or acquire additional reserves to replace our current and future production, our production rates will decline even if we drill the undeveloped locations that were included in our proved reserves. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are dependent on our success in economically finding or acquiring new reserves and efficiently developing our existing reserves.

Approximately 65% of our total estimated proved reserves are either developed non-producing or undeveloped (71% on a pro forma basis), and those reserves may not ultimately be produced or developed.

As of December 31, 2005, approximately 15% of our total estimated proved reserves were developed non-producing (27% on a pro forma basis) and approximately 50% were undeveloped (44% on a pro forma basis). These reserves may not ultimately be developed or produced. Furthermore, not all of our undeveloped or developed non-producing reserves may be ultimately produced during the time periods we have planned, at the costs we have budgeted, or at all, which in turn may have in a material adverse effect on our results of operations.

Any production problems related to our Gulf of Mexico properties could reduce our revenue, profitability and cash flow materially.

A substantial portion of our exploration and production activities is 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.

If any of these factors were to occur with respect to a particular project, we could lose all or a part of our investment in the project, or we could fail to realize the expected benefits from the project, either of which could materially and adversely affect our revenues and profitability.

Our exploratory drilling projects are based in part on seismic data, which is costly and cannot ensure the commercial success of the project.

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. 3-D seismic data does not enable an interpreter to conclusively determine whether hydrocarbons are present or producible economically. In addition, the use of 3-D seismic and other advanced technologies require greater predrilling expenditures than other 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, ability to replace reserves 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;
- blow-outs and surface cratering;
- uncontrollable flows of underground natural gas, oil and formation water;
- natural disasters, such as hurricanes and other adverse weather conditions;
- pipe or cement failures;
- casing collapses;
- lost or damaged 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 occurs, 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 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. For more information on the impact of recent hurricanes on our operations, see Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Developments.

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. 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 utilize subsea completion and tieback technology. As of September 30, 2006, we had 18 subsea wells. These wells were tied back to 13 host production facilities for production processing. An additional nine wells were then under development for tieback to five additional host production facilities. The installation of subsea production systems to tieback and operate subsea wells requires substantial time and the use of advanced and very sophisticated installation equipment supported by remotely operated vehicles. 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 in the shallow waters of the Gulf of Mexico. 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, our hedging arrangements reduced the benefit we received from increases in the prices for oil and natural gas by approximately $49 million for the calendar year 2005 and increased the benefit we received by $1.5 million for the nine months ended September 30, 2006. 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, exploration arrangements with other parties, the issuance of debt securities, 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 (subject to certain federal tax limitations during the two-year period following the spin-off). 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 (including the Forest Gulf of Mexico properties we acquired in March 2006) 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, including the Forest Gulf of Mexico properties, 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 wells or delay initial production for lack of a market or because of inadequacy or unavailability of pipeline or gathering system capacity. When that occurs, we are unable to realize revenue from those wells until the production can be tied to a gathering system. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil and natural gas and realization of revenues.

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 in availability 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 are major and large independent oil and natural gas companies, and 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 adversely affect our ability to timely complete the exploration and development of our prospects.

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 timing or scope of drilling and development activities on properties we do not operate, and therefore we may not be in a position to control 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, or 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.

Compliance with MMS regulations could significantly delay or curtail our operations or require us to make material expenditures, all of which could have a material adverse effect on our financial condition or results of operations.

A significant portion of our operations are located on federal oil and natural gas leases that are administered by the MMS. As an offshore operator, we must obtain MMS approval for our exploration, development and production plans prior to commencing such operations. The MMS has promulgated regulations that, among other things, require us to meet stringent engineering and construction specifications, restrict the flaring or venting of natural gas, govern the plug and abandonment of wells located offshore and the installation and removal of all production facilities, and govern the calculation of royalties and the valuation of crude oil produced from federal leases.

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 which 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. The impact of Hurricanes Katrina and Rita have resulted in escalating insurance costs and less favorable coverage terms. In addition, we have not yet been able to determine the full extent of our insurance recovery and the net cost to us resulting from the hurricanes. See Business Insurance Matters for more information.

Risks Relating to Our Merger with Forest Energy Resources

The integration of the Forest Gulf of Mexico operations will be difficult, and will divert our management s attention away from our normal operations.

There is a significant degree of difficulty and management involvement inherent in the process of integrating the Forest Gulf of Mexico operations. These difficulties include:

- the challenge of integrating the Forest Gulf of Mexico operations while carrying on the ongoing operations of our business;
- the challenge of managing a significantly larger company, with more than twice the PV10 of Mariner prior to the merger;
- the possibility of faulty assumptions underlying our expectations;
- the difficulty associated with coordinating geographically separate organizations;
- the challenge of integrating the business cultures of the two companies;
- attracting and retaining personnel associated with the Forest Gulf of Mexico operations following the merger; and
- the challenge and cost of integrating the information technology systems of the two companies.

The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

If we fail to realize the anticipated benefits of the merger, our results of operations may be lower than we expect.

The success of the merger will depend, in part, on our ability to realize the anticipated growth opportunities from combining the Forest Gulf of Mexico operations with Mariner. Even if we are able to successfully combine the two businesses, it may not be possible to realize the full benefits of the proved reserves, enhanced growth of production volume, cost savings from operating synergies and other benefits that we currently expect to result from the merger, or realize these benefits within the time frame that is currently expected. The benefits of the merger may be offset by operating losses relating to changes in commodity prices, or in oil and gas industry conditions, or by risks and uncertainties relating to the combined company s exploratory prospects, or an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from the merger, our results of operations may be adversely affected.

We expect to incur significant charges relating to the integration plan that could materially and adversely affect our period-to-period results of operations.

We anticipate that from time to time we will incur charges to our earnings in connection with the integration of the Forest Gulf of Mexico operations into our business. These charges will include expenses incurred in connection with relocating and retaining employees and increased professional and consulting costs. We also expect to incur significant expenses related to being a public company. We are not yet able to quantify the costs or timing of the integration. Some factors affecting the cost of the integration include the training of new employees, the amount of severance and other employee-related payments resulting from the merger, and the limited length of time during which transitional services were provided by Forest. During the nine months ended September 30, 2006, we incurred approximately $2.6 million of such costs.

In order to preserve the tax-free treatment of the spin-off of Forest Energy Resources, we are required to abide by potentially significant restrictions which could limit our ability to undertake certain corporate actions (such as the issuance of our common shares or the undertaking of a change in control) that otherwise could be advantageous.

In connection with the merger we entered into a tax sharing agreement, which imposes ongoing restrictions on Forest and on us to ensure that applicable statutory requirements under the Internal Revenue Code of 1986, as amended, or the Code, and applicable Treasury regulations continue to be met so that the spin-off of Forest Energy Resources remains tax-free to Forest and its shareholders. As a result of these restrictions, our ability to engage in certain transactions, such as the redemption of our common stock, the issuance of equity securities and the utilization of our stock as currency in an acquisition, will be limited for a period of two years following the spin-off.

If Forest or Mariner takes or permits an action to be taken (or omits to take an action) that causes the spin-off to become taxable, the relevant entity generally will be required to bear the cost of the resulting tax liability to the extent that the liability results from the actions or omissions of that entity. If the spin-off became taxable, Forest would be expected to recognize a substantial amount of income, which would result in a material amount of taxes. Any such taxes allocated to us would be expected to be material to us, and could cause our business, financial condition and operating results to suffer. These restrictions may reduce our ability to engage in certain business transactions that otherwise might be advantageous to us and could have a negative impact on our business.

Risks Relating to the Notes

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments, including the notes. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt, including the notes. Many of these factors, such as oil and gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations, including our obligations under the notes, or to obtain alternative financing, could materially and adversely affect our business, financial condition, results of operations and prospects.

The notes and the guarantees will be unsecured and effectively subordinated to our and our subsidiary guarantors existing and future secured indebtedness.

The notes and the guarantees are general unsecured senior obligations ranking effectively junior in right of payment to all existing and future secured debt of ours and that of each subsidiary guarantor, respectively, including obligations under our credit facility, to the extent of the value of the collateral securing the debt. As of September 30, 2006, after giving effect to borrowings under our amended and restated credit facility and to the offering of the old notes and the application of the proceeds therefrom, our total indebtedness was $614.0 million, $300.0 million of which was the old notes and $314.0 million of which effectively was senior in right of payment to the notes to the extent of the value of the collateral securing that indebtedness. We also then had three letters of credit outstanding for $40.0 million, $10.4 million and $4.2 million, each of which effectively is senior to the notes to the extent of the collateral securing such indebtedness. Further, we then had $121.4 million in additional borrowing capacity under our credit facility which if borrowed would have been secured debt effectively senior in right of payment to the notes to the extent of the value of the collateral securing that indebtedness.

If we or a subsidiary guarantor are declared bankrupt, become insolvent or are liquidated or reorganized, any secured debt of ours or that subsidiary guarantor will be entitled to be paid in full from our assets or the assets of the guarantor, as applicable, securing that debt before any payment may be made with respect to the notes or the affected guarantees. Holders of the notes participate ratably with all holders of our unsecured indebtedness that does not rank junior to the notes, including all of our other general creditors, based upon the respective amounts owed to each holder or creditor, in our remaining assets. In any of the foregoing events, we cannot assure you that there will be sufficient assets to pay amounts due on the notes. As a result, holders of the notes would likely receive less, ratably, than holders of secured indebtedness.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations and business prospects and prevent us from fulfilling our obligations under the notes.

Our level of indebtedness, and the covenants contained in the agreements governing our debt, could have important consequences for our operations, including by:

- making it more difficult for us to satisfy our obligations under the notes or other debt and increasing the risk that we may default on our debt obligations;

requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;

limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;

limiting management s discretion in operating our business;

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- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- detracting from our ability to withstand successfully a downturn in our business or the economy generally;
- placing us at a competitive disadvantage against less leveraged competitors; and
- making us vulnerable to increases in interest rates, because debt under our credit facility will in some cases vary with prevailing interest rates.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the consequent acceleration of our obligation to repay outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions.

In addition, under the terms of our credit facility and the indenture, we must comply with certain financial covenants, including current asset and total debt ratio requirements. Our ability to comply with these covenants in future periods will depend on our ongoing financial and operating performance, which in turn will be subject to general economic conditions and financial, market and competitive factors, in particular the selling prices for our products and our ability to successfully implement our overall business strategy.

The breach of any of the covenants in the indenture or the credit facility could result in a default under the applicable agreement which would permit the applicable lenders or noteholders, as the case may be, to declare all amounts outstanding thereunder to be due and payable, together with accrued and unpaid interest. We may not have sufficient funds to make such payments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt. The terms of our debt, including our credit facility, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions, restrictions in our tax sharing agreement with Forest and the value of our assets and operating performance at the time of such offering or other financing. We cannot assure you that any such offering, refinancing or sale of assets could be successfully completed.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

Despite our and our subsidiaries current level of indebtedness, we may still be able to incur substantially more debt. This could further exacerbate the risks associated with our substantial indebtedness.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future, subject to certain limitations. The terms of our indenture will not prohibit us or our subsidiaries from doing so. For example, as of September 30, 2006, we were able to borrow up to $362.5 million on a revolving basis under our credit facility that was increased to $450 million in October 2006. If new debt is added to our current debt levels, the related risks that we and our subsidiaries now face could intensify. Our level of indebtedness could, for instance, prevent us from engaging in transactions that might otherwise be beneficial to us or from making desirable capital expenditures. This could put us at a competitive disadvantage relative to other less leveraged competitors that have more cash flow to devote to their operations. In addition, the incurrence of additional

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indebtedness could make it more difficult to satisfy our existing financial obligations, including those relating to the notes.

We may not be able to repurchase the notes upon a change of control.

Upon the occurrence of certain change of control events, we are required to offer to repurchase all or any part of the notes then outstanding for cash at 101% of the principal amount. The source of funds for any repurchase required as a result of any change of control will be our available cash or cash generated from our operations or other sources, including:

- borrowings under our credit facilities or other sources;
- sales of assets; or
- sales of equity.

We cannot assure you that sufficient funds would be available at the time of any change of control to repurchase your notes. In addition, our credit facility prohibits, and any future credit facilities may prohibit, such repurchases. Additionally, a change of control (as defined in the indenture for the notes) will be an event of default under our credit facility that would permit the lenders to accelerate the debt outstanding under the credit facility. Finally, using available cash to fund the potential consequences of a change of control may impair our ability to obtain additional financing in the future, which could negatively impact our ability to conduct our business operations.

A subsidiary guarantee could be voided if it constitutes a fraudulent transfer under U.S. bankruptcy or similar state law, which would prevent the holders of the notes from relying on that subsidiary to satisfy claims.

Under U.S. bankruptcy law and comparable provisions of state fraudulent transfer laws, our subsidiary guarantees can be voided, or claims under the subsidiary guarantees may be subordinated to all other debts of that subsidiary guarantor if, among other things, the subsidiary guarantor, at the time it incurred the indebtedness evidenced by its guarantee or, in some states, when payments become due under the guarantee, received less than reasonably equivalent value or fair consideration for the incurrence of the guarantee and:

- was insolvent or rendered insolvent by reason of such incurrence;
- was engaged in a business or transaction for which the guarantor s remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they mature.

Our subsidiary guarantees may also be voided, without regard to the above factors, if a court found that the subsidiary guarantor entered into the guarantee with the actual intent to hinder, delay or defraud its creditors.

A court would likely find that a subsidiary guarantor did not receive reasonably equivalent value or fair consideration for its guarantee if the subsidiary guarantor did not substantially benefit directly or indirectly from the issuance of the guarantees. If a court were to void a subsidiary guarantee, you would no longer have a claim against the subsidiary guarantor. Sufficient funds to repay the notes may not be available from other sources, including the remaining subsidiary guarantors, if any. In addition, the court might direct you to repay any amounts that you already received from the subsidiary guarantor.

The measures of insolvency for purposes of fraudulent transfer laws vary depending upon the governing law. Generally, a guarantor would be considered insolvent if:

- the sum of its debts, including contingent liabilities, were greater than the fair saleable value of all its assets;

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the present fair saleable value of its assets is less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and mature; or

it could not pay its debts as they become due.

Each subsidiary guarantee contains a provision intended to limit the subsidiary guarantor s liability to the maximum amount that it could incur without causing the incurrence of obligations under its subsidiary guarantee to be a fraudulent transfer. Such provision may not be effective to protect the subsidiary guarantees from being voided under fraudulent transfer law.

A financial failure by us or our subsidiaries may result in the assets of any or all of those entities becoming subject to the claims of all creditors of those entities.

A financial failure by us or our subsidiaries could affect payment of the notes if a bankruptcy court were to substantively consolidate us and our subsidiaries. If a bankruptcy court substantively consolidated us and our subsidiaries, the assets of each entity would become subject to the claims of creditors of all entities. This would expose holders of notes not only to the usual impairments arising from bankruptcy, but also to potential dilution of the amount ultimately recoverable because of the larger creditor base. Furthermore, forced restructuring of the notes could occur through the cram-down provisions of the bankruptcy code. Under these provisions, the notes could be restructured over your objections as to their general terms, primarily interest rate and maturity.

THE EXCHANGE OFFER

This section of the prospectus describes certain aspects of the exchange offer which expired on November 9, 2006. Each broker-dealer (other than an affiliate of ours) that receives new notes for its own account in the exchange offer in exchange for securities that were acquired by such broker-dealer as a result of market-making or other trading activities must deliver a prospectus meeting the requirements of the Securities Act of 1933 in connection with any resale of new notes. We have agreed that, for a period of 90 days after the exchange date, we will make the prospectus available to any broker-dealer for use in connection with any such resale. While we believe that this description covers the material terms of the exchange offer that may remain relevant notwithstanding expiration or the exchange offer, this summary may not contain all of the information that is important to you. You should carefully read this entire document.

Purpose and Effects of the Exchange Offer

We initially issued $300.0 million principal amount of old notes on April 24, 2006 in a private offering. The initial purchasers subsequently offered and sold a portion of the old notes only to qualified institutional buyers as defined in and in compliance with Rule 144A and outside the United States in compliance with Regulation S of the Securities Act.

In connection with the sale of the old notes, we entered into an exchange and registration rights agreement, which requires us

- to cause the old notes to be registered under the Securities Act, or

- to file with the SEC a registration statement under the Securities Act with respect to an issue of new notes identical in all material respects to the old notes, and

- use our commercially reasonable efforts to cause such registration statement to become effective under the Securities Act, and

- upon the effectiveness of that registration statement, to offer to the holders of the old notes the opportunity to exchange their old notes for a like principal amount of new notes, which will be issued without a restrictive legend and which may be reoffered and resold by the holder without restrictions or limitations under the Securities Act.

We made the exchange offer to satisfy our obligations under the exchange and registration rights agreement. The term holder with respect to the exchange offer means any person in whose name old notes are registered on our or the Depository Trust Company s (DTC) books or any other person who has obtained a properly completed bond power from the registered holder, or any person whose old notes are held of record by DTC who desires to deliver such old notes by book-entry transfer at DTC.

We have not requested, and do not intend to request, an interpretation by the staff of the SEC with respect to whether the new notes issued in the exchange offer in exchange for the old notes may be offered for sale, resold or otherwise transferred by any holder without compliance with the registration and prospectus delivery provisions of the Securities Act. Based on interpretations by the staff of the SEC set forth in no-action letters issued to third parties, we believe the new notes issued in exchange for old notes may be offered for resale, resold and otherwise transferred by any holder without compliance with the registration and prospectus delivery provisions of the Securities Act provided that:

you are not a broker-dealer who purchased old notes directly from us for resale pursuant to Rule 144A or any other available exemption under the Securities Act,

you are not our or any subsidiary guarantor s affiliate , or

you acquire the new notes in the ordinary course of your business and that you have no arrangement or understanding with any person to participate in the distribution of the new notes.

Any holder who tenders in the exchange offer with the intention to participate, or for the purpose of participating, in a distribution of the new notes or who is our affiliate may not rely upon such interpretations by the staff of the SEC and, in the absence of an exemption, must comply with the registration and prospectus

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delivery requirements of the Securities Act in connection with any secondary resale transaction. Any holder to comply with such requirements may incur liabilities under the Securities Act for which the holder is not indemnified by us.

Resale of the New Notes; Plan of Distribution

Each broker-dealer that receives new notes for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of new notes. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of new notes received in exchange for old notes where such old notes were acquired as a result of market-making activities or other trading activities. In addition, until January 8, 2007, all dealers effecting transactions in the new notes, whether or not participating in this distribution, may be required to deliver a prospectus. This requirement is in addition to the obligation of dealers to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

We will not receive any proceeds from any sale of new notes by broker-dealers. New notes received by broker-dealers for their own account pursuant to the exchange offer may be sold from time to time in one or more transactions:

- in the over-the-counter market,
- in negotiated transactions,
- through the writing of options on the new notes or a combination of such methods of resale,
- at market prices prevailing at the time of resale,
- at prices related to such prevailing market prices, or
- at negotiated prices.

Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer or the purchasers of any such new notes.

Any broker-dealer that resells new notes received for its own account pursuant to the exchange offer and any broker or dealer that participates in a distribution of such new notes may be deemed to be an underwriter within the meaning of the Securities Act and any profit on any such resale of new notes and any commission on concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The letter of transmittal states that, by acknowledging that it will deliver a prospectus and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act.

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USE OF PROCEEDS

The exchange offer was intended to satisfy our obligations under the registration rights agreement. We will not receive any proceeds from the issuance of the new notes in the exchange offer. In consideration for issuing the new notes as contemplated in this prospectus, we will receive, in exchange, outstanding old notes in like principal amount. We will cancel all old notes surrendered in exchange for new notes in the exchange offer. As a result, the issuance of the new notes will not result in any increase or decrease in our indebtedness.

The net proceeds from the offering of the sale of the old notes in the initial private placement were approximately $287.9 million. We used those proceeds, together with cash on hand, to repay borrowings under our amended and restated credit facility. The borrowings under the credit facility were used to:

- refinance indebtedness incurred by Forest Energy Resources in connection its acquisition by us.
- pay transaction expenses associated with the merger; and
- repay $165.0 million under our prior credit facility with Union Bank of California.

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CAPITALIZATION

The following table sets forth our consolidated capitalization as of September 30, 2006.

This table should be read together with our financial statements and the related notes included in this prospectus.

	As of September 30, 2006 (In thousands)	
Long-term debt:		
Credit facility revolving note(1)	$	314,000
Senior Notes		300,000
Total long-term debt		614,000
Stockholders Equity	$	1,267,062
Total capitalization	$	1,881,062

(1) In connection with our merger with Forest Energy Resources on March 2, 2006, we amended and restated our existing secured credit facility to, among other things, increase maximum credit availability to $500 million for revolving loans, including up to $50 million in letters of credit, with a $400 million borrowing base as of that date; add an additional dedicated $40 million letter of credit facility that does not affect the borrowing base; and add Mariner Energy Resources, Inc. as a co-borrower. Our credit facility was further amended in April 2006 to increase the borrowing base to $430 million which subsequently automatically reduced to $362.5 million upon closing of the offering of the old notes and then was increased to $450 million in October 2006, subject to redetermination or adjustment. The revolving credit facility matures on March 2, 2010. At September 30, 2006, approximately $328.6 million was outstanding under the revolving credit facility, including two letters of credit for $4.2 million and $10.4 million. The $40 million letter of credit outstanding as of September 30, 2006 under the dedicated letter of credit facility matures on March 2, 2009. See Management s Discussion and Analysis of Financial Condition and Results of Operations Credit Facility for more information.

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UNAUDITED PRO FORMA COMBINED CONDENSED FINANCIAL INFORMATION

The merger between a subsidiary of Mariner and Forest Energy Resources was consummated on March 2, 2006. Accordingly, actual balance sheet information of the combined company as of September 30, 2006 is included elsewhere in this prospectus.

The following unaudited pro forma combined statements of operations and explanatory notes present how the combined statements of Mariner and the Forest Gulf of Mexico operations may have appeared had the businesses actually been combined as of January 1, 2005.

The unaudited pro forma combined financial information has been derived from and should be read together with the historical consolidated financial statements of Mariner and the statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations, which are included elsewhere in this prospectus. The statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations do not include all of the costs of doing business.

The unaudited pro forma combined condensed financial information is for illustrative purposes only. The financial results may have been different had the Forest Gulf of Mexico operations been an independent company and had the companies always been combined. You should not rely on the unaudited pro forma combined condensed financial information as being indicative of the historical results that would have been achieved had the merger occurred in the past or the future financial results that Mariner will achieve after the merger.

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MARINER ENERGY, INC.

UNAUDITED PRO FORMA COMBINED CONDENSED STATEMENT OF OPERATIONS
For the Nine Months Ended September 30, 2006

	Mariner Historical(1)	Forest Energy Resources, Inc. Historical(2)	Merger Adjustments(3)	Mariner Pro Forma Combined
	(In thousands, except share data)			
Revenues:				
Oil & gas sales	$ 211,587	$ 291,885		$ 503,472
Other revenues	2,401			2,401
Total revenues	213,988	291,885		505,873
Costs and Expenses:				
Lease operating expenses	27,089	51,765		78,854
Severance and ad valorem taxes	5,205	1,203		6,408
Transportation expenses	2,728	1,458		4,186
General and administrative expenses	23,872	809	(4)	24,681
Depreciation, depletion and amortization	82,194		136,797(5)	218,991
Total costs and expenses	141,088	55,235	136,797	333,120
OPERATING INCOME	72,900	236,650	(136,797)	172,753
Interest:				
Income	487			487
Expense, net of amounts capitalized	(17,693)		(10,786)(6)	(28,479)
Income before taxes	55,694	236,650	(147,583)	144,761
Provision for income taxes	(20,966)		(31,173)(7)	(52,139)
NET INCOME	$ 34,728	$ 236,650	$ (178,756)	$ 92,622
Earnings per share:				
Net Income per share basic	$ 1.02			$ 1.09
Net Income per share diluted	$ 1.00			$ 1.09
Weighted average shares outstanding basic	34,133,279		50,637,010	84,770,289
Weighted average shares outstanding diluted	34,557,697		50,687,850	85,245,547

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MARINER ENERGY, INC.

UNAUDITED PRO FORMA COMBINED CONDENSED STATEMENT OF OPERATIONS
For the Year Ended December 31, 2005

	Mariner Historical(1)	Forest Energy Resources, Inc. Historical(2)	Merger Adjustments(3)	Mariner Pro Forma Combined
	(In thousands, except share data)			
Revenues:				
Oil & gas sales	$ 196,122	$ 392,272	$	$ 588,394
Other revenues	3,588			3,588
Total revenues	199,710	392,272		591,982
Costs and Expenses:				
Lease operating expenses	24,882	78,001		102,883
Severance and ad valorem taxes	5,000	2,738		7,738
Transportation expenses	2,336	3,383		5,719
General and administrative expenses	37,053		(4)	37,053
Depreciation, depletion and amortization	59,426		270,390(5)	329,816
Impairment of production equipment held for use	1,845			1,845
Total costs and expenses	130,542	84,122	270,390	485,054
OPERATING INCOME	69,168	308,150	(270,390)	106,928
Interest:				
Income	779			779
Expense, net of amounts capitalized	(8,172)		(10,378)(8)	(18,550)
Income before taxes	61,775	308,150	(280,768)	89,157
Provision for income taxes	(21,294)		(9,911)(7)	(31,205)
NET INCOME	$ 40,481	$ 308,150	$ (290,679)	$ 57,952
Earnings per share:				
Net Income per share basic	$ 1.24			$ 0.70
Net Income per share diluted	$ 1.20			$ 0.69
Weighted average shares outstanding basic	32,667,582		50,637,010	83,304,592
Weighted average shares outstanding diluted	33,766,577		50,687,850	84,454,427

(1) The historical Mariner information presented excludes activity related to the Forest Gulf of Mexico operations as Mariner acquired them in the merger consummated on March 2, 2006.

(2) The Forest Gulf of Mexico operations historically have been operated as part of Forest s total oil and gas operations. No historical GAAP-basis financial statements exist for the Forest Gulf of Mexico operations on a stand-alone basis; however, statements of revenues and direct operating expenses are presented for the nine months ended September 30, 2006 and for the year ended December 31, 2005.

(3) Transaction costs consisting of accounting, consulting and legal fees are anticipated to be approximately $10.3 million. These costs are directly attributable to the transaction and have been excluded from the pro forma financial statements as they represent material nonrecurring charges.

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(4) The pro forma general and administrative expenses do not include costs associated with the Forest Gulf of Mexico assets. Mariner believes the overhead costs associated with these operations in 2006 will be approximately $6.4 million, net of capitalized amounts.

(5) To adjust depreciation, depletion and amortization expense to give effect to the acquisition of the Forest Gulf of Mexico operations and their step-up in value using the unit of production method under the full cost method of accounting.

(6) To adjust interest expense to give effect to the financing activities in connection with the organization of Forest Energy Resources assuming an interest rate of 6.375% based on the terms of the senior bank credit facility obtained by Forest Energy Resources. The interest rates used are 30-day LIBOR plus 1.50%, or 6.375%, as of September 30, 2006. A change in interest rates of approximately 10% would result in a change in pro forma combined interest of approximately $0.9 million for the nine months ended September 30, 2006.

(7) To record income tax expense on the combined company results of operations based on a statutory federal tax rate of 35.0%.

(8) To adjust interest expense to give effect to the financing activities in connection with the organization of Forest Energy Resources assuming an interest rate of 5.89% for the year ended December 31, 2005 based on the terms of the senior term loan facility obtained by Forest Energy Resources. The interest rates used are 30-day LIBOR plus 1.50%, or 5.89% as of December 31, 2005. A change in interest rates of approximately 10% would result in a change in pro forma combined interest expense of approximately $1.0 million for the year ended December 31, 2005.

Supplemental Pro Forma Combined Oil and Gas Reserve and Standardized Measure Information (Unaudited)

The following unaudited supplemental pro forma oil and natural gas reserve tables present how the combined oil and gas reserve and standardized measure information of Mariner and the Forest Gulf of Mexico operations may have appeared had the businesses actually been combined as of January 1, 2005. The combination of the Forest Gulf of Mexico operations with Mariner s operations is expected to cause the average reserve life of Mariner s oil and gas properties to decrease from current levels and to result in a higher rate of depreciation, depletion, and amortization for the combined operations. For example, the estimated proved reserves of the Forest Gulf of Mexico properties as of December 31, 2005 were 306.1 Bcfe and production for the year ended December 31, 2005 was approximately 65.8 Bcfe, a reserve life on an annualized basis of 4.7. This ratio is indicative of the relatively higher productive rates of offshore oil and gas properties when compared to most onshore fields. While the higher productive rates generally result in a faster return on investment than onshore fields, they also result in a faster depletion of the underlying proved reserves and a corresponding higher rate of depreciation, depletion, and amortization. As of December 31, 2005, Mariner s proved reserves totaled 337.6 Bcfe and production for the year ended December 31, 2005 was approximately 29.1 Bcfe, a reserve life on an annualized basis of 11.6. For the combined operations, as of December 31, 2005, proved reserves would have totaled approximately 643.7 Bcfe and production for the year ended December 31, 2005 would have totaled 94.9 Bcfe, a reserve life on an annualized basis of 6.8. The Supplemental Pro Forma Combined Oil and Gas Reserve and Standardized Measure Information is for illustrative purposes only. You should refer to footnote 10 in Mariner s Notes to the Financial Statements on page F-56 and footnote 3 in Forest s Gulf of Mexico Operations Notes to Statements of Revenues and Direct Operating Expenses for additional information presented in accordance with the requirements of Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities.

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ESTIMATED PRO FORMA COMBINED QUANTITIES OF PROVED RESERVES

	Mariner Historical			Forest Energy Resources, Inc. Historical			Mariner Pro Forma Combine		
	Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (MMcfe)	Liquids (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (MMcfe)	Liquids (Mbbl)	Natural Gas (MMcf)	Natur Gas Equival (MMcf
ember 31, 2004	14,255	151,933	237,465	11,650	269,808	339,708	25,905	421,741	577,1
isions of ious estimates	835	963	5,971	3,123	4,815	23,553	3,958	5,778	29,5
ensions, overies and r additions	1,167	22,307	29,309	504	5,639	8,663	1,671	27,946	37,9
luction	(1,791)	(18,354)	(29,100)	(2,783)	(49,120)	(65,818)	(4,574)	(67,474)	(94,9
chases of rves in place	7,181	50,837	93,923				7,181	50,837	93,9
ember 31, 2005	21,647	207,686	337,568	12,494(1)	231,142	306,106(1)	34,141	438,828	643,6

(1) Includes 3,223 Mbbls of natural gas liquids.

ESTIMATED PRO FORMA COMBINED QUANTITIES OF PROVED DEVELOPED RESERVES

	Mariner Historical			Forest Energy Resources, Inc. Historical			Mariner Pro Forma Combined		
	Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (MMcfe)	Liquids (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (MMcfe)	Liquids (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (MMcfe)
December 31, 2005	9,564	110,011	167,395	8,792	142,143	194,895	18,356	252,154	362,290

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PRO FORMA COMBINED STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	For the Year Ending December 31, 2005		
	Mariner Historical	Forest Energy Resources, Inc. Historical	Mariner Pro Forma Combined
Future cash inflows	$ 3,451,321	$ 2,849,998	$ 6,301,319
Future production costs	(687,583)	(226,248)	(913,831)
Future development costs	(386,497)	(386,855)	(773,352)
Future income taxes	(695,921)	(649,002)	(1,344,923)
Future net cash flows	1,681,320	1,587,893	3,269,213
Discount of future net cash flows at 10% per annum	(774,755)	(292,730)	(1,067,485)
Standardized measure of discounted future net cash flows	$ 906,565	$ 1,295,163	$ 2,201,728
Balance, beginning of period	$ 494,382	$ 925,837	$ 1,420,219
Increase (decrease) in discounted future net cash flows:			
Sales and transfers of oil and gas produced, net of production costs	(213,189)	(436,385)	(649,574)
Net changes in prices and production costs	425,317	692,164	1,117,481
Extensions and discoveries, net of future development and production costs	119,501	53,744	173,245
Purchases of reserves in place	189,782		189,782
Development costs during period and net change in development costs	46,632	7,022	53,654
Revision of previous quantity estimates	16,323	109,207	125,530
Net change in income taxes	(201,647)	(178,643)	(380,290)
Accretion of discount before income taxes	49,438	122,217	171,655
Changes in production rates (timing) and other	(19,974)		(19,974)
Balance, end of period	$ 906,565	$ 1,295,163	$ 2,201,728

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SELECTED HISTORICAL FINANCIAL INFORMATION FOR MARINER

The following table shows Mariner s summary historical consolidated financial data as of and for the nine months ended September 30, 2006 and September 30, 2005, the year ended December 31, 2005, the period from January 1, 2004 through March 2, 2004, the period from March 3, 2004 through December 31, 2004, and each of the three years ended December 31, 2003. The summary historical consolidated financial data for the year ended December 31, 2005, the period from January 1, 2004 through March 2, 2004, the period from March 3, 2004 through December 31, 2004, and the year ended December 31, 2003 are derived from Mariner s audited financial statements included herein, and the historical consolidated financial data as of and for the two years ended December 31, 2002 are derived from Mariner s audited financial statements that are not included herein. The summary historical consolidated financial data for the nine months ended September 30, 2006 and the nine months ended September 30, 2005 has been derived from Mariner s unaudited financial statements. You should read the following data in connection with 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 with Forest Energy Resources. Mariner s historical results are not necessarily indicative of results to be expected in future periods.

The merger between a subsidiary of Mariner and Forest Energy Resources was consummated on March 2, 2006. Accordingly, the financial information as of September 30, 2006 below includes the Forest Gulf of Mexico operations as of and after March 2, 2006.

On March 2, 2004, Mariner s former indirect parent, Mariner Energy LLC, merged with MEI Acquisitions, LLC, an affiliate of the private equity funds, Carlyle/Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC. The financial information contained herein is presented in the style of Post-2004 Merger activity (for the March 3, 2004 through December 31, 2004 period, the year ended December 31, 2005 and the nine months ended September 30, 2006 and September 30, 2005) and Pre-2004 Merger activity (for all periods prior to March 2, 2004) 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.

	Post-2004 Merger					Pre-2004 Merger		
	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005	Year Ended December 31, 2005	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004	Year Ended December 31, 2003	Year Ended December 31, 2002	Year Ended December 31, 2001
	(In millions, except per share data)							
Statement of Operations Data:								
Total revenues(1)	$ 438.4	$ 151.2	$ 199.7	$ 174.4	$ 39.8	$ 142.5	$ 158.2	$ 155.0
Lease operating expenses	62.9	17.7	24.9	19.3	3.5	23.2	25.2	19.2
	5.7	2.5	5.0	2.1	0.6	1.5	0.9	0.9

Severance and ad valorem taxes								
Transportation expenses	4.0	1.7	2.3	1.9	1.1	6.3	10.5	12.0
Depreciation, depletion and amortization	192.2	43.4	59.4	54.3	10.6	48.3	70.8	63.5
Impairment of production equipment held for use		0.5	1.8	1.0				
Derivative settlement						3.2		
Impairment of Enron related receivables							3.2	29.5
General and administrative expenses	25.1	26.7	37.1	7.6	1.1	8.1	7.7	9.3
Operating income	148.5	58.7	69.2	88.2	22.9	51.9	39.9	20.6
Interest income	0.5	0.7	0.8	0.2	0.1	0.8	0.4	0.7
Interest expense	(26.4)	(5.4)	(8.2)	(6.0)		(7.0)	(10.3)	(8.9)
Income before income taxes	122.6	54.0	61.8	82.4	23.0	45.7	30.0	12.4
Provision for income taxes	(44.4)	(18.4)	(21.3)	(28.8)	(8.1)	(9.4)		

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	Post-2004 Merger					Pre-2004 Merger		
	Nine Months Ended September 30,		Year Ended	Period from March 3, 2004 through	Period from January 1, 2004 through	Year Ended December 31,		
	2006	2005	December 31, 2005	December 31, 2004	March 2, 2004	2003	2002	2001
	(In millions, except per share data)							
Income before cumulative effect of change in accounting method net of tax effects	$ 78.2	$ 35.6	$ 40.5	$ 53.6	$ 14.9	$ 36.3	$ 30.0	$ 12.4
Income before cumulative effect per common unit								
Basic	1.07	1.10	$ 1.24	$ 1.80	$ 0.50	$ 1.22	$ 1.01	$ 0.42
Diluted	1.06	1.07	1.20	1.80	0.50	1.22	1.01	0.42
Cumulative effect of changes in accounting method						1.9		
Net income	$ 78.2	$ 35.6	$ 40.5	$ 53.6	$ 14.9	$ 38.2	$ 30.0	$ 12.4
Net income per common share								
Basic	$ 1.07	$ 1.10	$ 1.24	$ 1.80	$ 0.50	$ 1.29	$ 1.01	$ 0.42
Diluted	1.06	1.07	1.20	1.80	0.50	1.29	1.01	0.42
Capital Expenditure and Disposal Data:								
Exploration, including leasehold/seismic	169.1	23.6	$ 60.9	$ 40.4	$ 7.5	$ 31.6	$ 40.4	$ 66.3
Development and other	347.9	106.8	191.8	93.2	7.8	51.7	65.7	98.2
Proceeds from property conveyances	(2.0)					(121.6)	(52.3)	(90.5)
Total capital expenditures net of proceeds from property conveyances	$ 515.0	$ 130.4	$ 252.7	$ 133.6	$ 15.3	$ (38.3)	$ 53.8	$ 74.0

(1) Includes effects of hedging.

	Post-2004 Merger				Pre-2004 Merger		
	September 30,		December 31,	December 31,	December 31,		
	2006	2005	2005	2004	2004	2003	2001
	(In millions)						
Balance Sheet Data(1)							
Property and equipment, net, full cost method	$ 2,061.9	$ 393.3	$ 515.9	$ 303.8	$ 207.9	$ 287.6	$ 290.6
Total assets	2,700.7	502.2	665.5	376.0	312.1	360.2	363.9
Long-term debt, less current maturities	614.0	79.0	156.0	115.0		99.8	99.8
Stockholders equity	1,267.1	178.6	213.3	133.9	218.2	170.1	180.1
Working capital (deficit)(2)	(75.3)	(30.2)	(46.4)	(18.7)	38.3	(24.4)	(19.6)
Other Financial Data							
Ratio of Earnings to Fixed Charges(3)	5.43	10.23	7.88	17.17	6.83	3.56	1.82

(1) Balance sheet data as of September 30, 2006 reflects consolidation of the assets of the Forest Gulf of Mexico operations as of March 2, 2006. Balance sheet data as of December 31, 2004 reflects purchase accounting adjustments to oil and gas properties, total assets and stockholders equity resulting from the acquisition of our former indirect parent on March 2, 2004.

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(2) Working capital (deficit) excludes current derivative assets and liabilities, deferred tax assets and restricted cash.

(3) For the purposes of determining the ratio of earnings to fixed charges, earnings consist of the sum of income before taxes, plus fixed charges, less capitalized interest, and fixed charges consist of interest expense (net of capitalized interest), plus capitalized interest, plus amortized discounts related to indebtedness.

	Post-2004 Merger				Pre-2004 Merger			
	Nine Months Ended September 30,		Year Ended	Period from March 3, 2004 through	Period from January 1, 2004 through	Year Ended December 31,		
	2006	2005	December 31, 2005	December 31, 2004	March 2, 2004	2003	2002	2001
	(In millions, except per share data)							
Other Financial Data:								
EBITDA(1)	$ 340.7	$ 102.7	$ 130.4	$ 143.5	$ 33.4	$ 100.3	$ 113.9	$ 113.6
Net cash provided by operating activities	172.8	135.4	165.4	135.2	20.3	88.9	60.3	113.5
Net cash (used) provided by investing activities	(423.5)	(142.1)	(247.8)	(133.0)	(15.3)	52.9	(53.8)	(74.0)
Net cash (used) provided by financing activities	251.0	8.7	84.4	64.9		(100.0)		(30.0)
Reconciliation of Non-GAAP Measures:								
EBITDA(1)	$ 340.7	$ 102.7	$ 130.4	$ 143.5	$ 33.4	$ 100.3	$ 113.9	$ 113.6
Changes in working capital	(158.9)	25.1	20.0	6.2	(13.2)	7.2	(20.4)	7.5
Non-cash hedge gain/(loss)(2)	8.2	(3.6)	(4.5)	(7.9)		(2.0)	(23.2)	
Amortization/other	(0.3)	0.9	1.2	0.8			(0.1)	0.6
Stock compensation expense	9.0	17.6	25.7					
Net interest expense	(25.9)	(4.7)	(7.4)	(5.8)	0.1	(6.2)	(9.9)	(8.2)
Income tax expense		(2.6)		(1.6)		(10.4)		
Net cash provided by operating activities	$ 172.8	$ 135.4	$ 165.4	$ 135.2	$ 20.3	$ 88.9	$ 60.3	$ 113.5

(1) EBITDA means earnings before interest, income taxes, depreciation, depletion and amortization and impairments. For the nine months ended September 30, 2006 and 2005, EBITDA includes $9.0 million and

$17.6 million, respectively, in non-cash compensation expense related to restricted stock and stock options. For the year ended December 31, 2005, EBITDA includes $25.7 million in non-cash compensation expense related to restricted stock and stock options granted in 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 performance presented in accordance with generally accepted accounting principles or as a measure of a company s profitability or liquidity.

(2) 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 dedesignation 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. 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. The value at the time of the merger and included in 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.

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

Overview

We are an independent oil and natural gas exploration, development and production company with principal operations in the Gulf of Mexico and 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. As a result of increased drilling of shelf prospects, the acquisition of Forest s Gulf of Mexico assets located primarily on the shelf, and development activities in West Texas, 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 West Texas properties. As of December 31, 2005 (after giving effect to the merger transaction with Forest Energy Resources), approximately 56% of our proved reserves were classified as proved developed, with approximately 32% of the reserves located in West Texas, 19% in the Gulf of Mexico deepwater and 49% on the Gulf of Mexico shelf.

On March 2, 2004, Mariner s former indirect parent, Mariner Energy LLC, merged with MEI Acquisitions, 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 Mariner), $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 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-2004 Merger activity (for all periods prior to March 2, 2004) and Post-2004 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-2004 Merger (for the January 1 through March 2, 2004 period), Post-2004 Merger (for the March 3, 2004 through December 31, 2004 period) and Combined (for the full period from January 1 through December 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 $38 million of the remaining net proceeds of approximately $44 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 Enron Related Matters. As a result, after the private placement, an affiliate of MEI Acquisitions Holdings, LLC beneficially owned approximately 5.3% of our outstanding common stock.

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 are currently at or near historical highs and may fluctuate significantly in the future. Although we attempt to mitigate the impact of price declines and provide for more predictable cash flows 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. Conversely, the use of derivative instruments also can prevent us from realizing the full benefit of upward price movements.

Recent Developments

Forest Gulf of Mexico Merger. On March 2, 2006, a subsidiary of Mariner completed a merger transaction with Forest Energy Resources. Prior to the consummation of the merger, Forest transferred and contributed the assets and certain liabilities associated with its Gulf of Mexico operations to Forest Energy Resources. Immediately prior to the merger, Forest distributed all of the outstanding shares of Forest Energy Resources to Forest shareholders on a pro rata basis. Forest Energy Resources then merged with a newly-formed subsidiary of Mariner, became a new wholly-owned subsidiary of Mariner, and changed its name to Mariner Energy Resources, Inc. Immediately following the merger, approximately 59% of Mariner common stock was held by shareholders of Forest and approximately 41% of Mariner common stock was held by the pre-merger stockholders of Mariner. In the merger, Mariner issued 50,637,010 shares of common stock to Forest shareholders. Our acquisition of Forest Energy Resources added approximately 306 Bcfe of estimated proved reserves as of December 31, 2005, of which 76% were natural gas and 24% were oil and condensate.

West Cameron Acquisition. In August 2006, we acquired the interest of BP Exploration and Production Inc., which we refer to as BP , in West Cameron Block 110 and the southeast quarter of West Cameron Block 111 in the Gulf of Mexico. The interest was acquired by our subsidiary, Mariner Energy Resources, Inc., exercising its preferential right to purchase. BP retained its interest in depths below 15,000 feet. In the Forest merger, we acquired Forest Energy Resources 37.5% interest in the properties. As a result of the August 2006 acquisition, Mariner Energy Resources, Inc. now owns 100% of the working interest, exclusive of the deep rights retained by BP, and Mariner Energy, Inc. became operator of the interests owned by its subsidiary. The acquisition cost, net of preliminary purchase price adjustments, was approximately $70.9 million, which was financed by borrowing under our senior secured credit facility. A $10.4 million letter of credit under our senior secured credit facility also was issued in favor of BP to secure plugging and abandonment obligations. The acquisition adds proved reserves estimated by us to be 20 Bcfe as of August 1, 2006. Production associated with the acquired interest was approximately 11 MMcfe/day during July 2006.

Material Gulf of Mexico Discovery. In October 2006, we announced that we made a material conventional shelf discovery in the High Island 116 #5ST1 well, drilled to a total measured depth of 14,683 feet / 13,150 feet true vertical depth. The well encountered approximately 540 feet of net true vertical depth pay in thirteen sands. We anticipate completion and initial production in the fourth quarter of 2006. High Island 116 is part of the Forest Gulf of Mexico operations we acquired in March 2006. We have a 100% working interest and an approximate 72% net revenue interest in the well.

Effects of the 2005 Hurricane Season. In 2005, our operations were adversely affected by one of the most active and severe hurricane seasons in recorded history, resulting in shut-in production and startup delays. We estimate that as of September 30, 2006, approximately 12 MMcfe per day of production remained shut-in and approximately 33 MMcfe per day of production had recommenced since June 30, 2006. The four deepwater projects that experienced startup delays have recommenced production. As a result of ongoing repairs to pipelines, facilities, terminals and host facilities, we expect most of the remaining shut-in production to recommence by the end of 2006 and the balance in 2007, except that an immaterial amount of production is not expected to recommence.

We estimate that the costs to repair damage caused by the hurricanes to our platforms and facilities will be approximately $85 million. However, until we are able to complete all of the repair work, this estimate is subject to significant variance. For the insurance period covering the 2005 hurricane activity, we carried a $3 million annual deductible and a $0.5 million single occurrence deductible for the Mariner assets. Insurance covering the Forest Gulf of Mexico properties carried a $5 million deductible for each occurrence. Until the repairs are completed and we submit costs to our insurance underwriters for their review, the full extent of our insurance recoveries and the resulting net costs to us for Hurricanes Katrina and Rita will be unknown. See

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Business Insurance Matters. However, we expect the total costs not covered by the combined insurance policies to be less than $15 million.

2006 Highlights

For the nine months ended September 30, 2006, we recognized net income of $78.2 million on total revenues of $438.4 million compared to net income of $35.6 million on total revenues of $151.2 million for the nine months ended September 30, 2005. Production, revenues and net income increased significantly from results reported a year ago primarily as a result of consolidation as of March 2, 2006 of assets acquired in the merger transaction with Forest Energy Resources. Production for the first nine months of 2006 averaged 200 MMcfe per day (54.5 Bcfe total for the period), compared to average daily production of 82 MMcfe per day for the first nine months of 2005 (22.5 Bcfe total for the period). Production for the first nine months of 2006 continued to be adversely effected by the 2005 hurricane season.

2005 Highlights

During the year ended December 31, 2005, we recognized net income of $40.5 million on total revenues of $199.7 million compared to net income of $68.4 million on total revenues of $214.2 million in 2004. Net income decreased 41% compared to 2004, primarily due to recognizing $25.7 million of stock compensation expense in 2005, and a 23% decrease in production, partially offset by a 35% improvement in net commodity prices realized by us (before the effects of hedging.) Our 2005 results were also negatively impacted by increased hedging losses of $49.3 million in 2005 compared to a $19.8 million loss in 2004. We produced approximately 29.1 Bcfe during 2005 and our average daily production rate was 80 MMcfe compared to 37.6 Bcfe, or 103 MMcfe per day, for 2004. Production during the last two quarters of 2005 was negatively impacted by the effects of the 2005 hurricane season. We invested approximately $252.7 million in total capital in 2005 compared to $148.9 million in 2004.

Our 2005 results reflect the private placement of an additional 3.6 million shares of stock in March 2005. The net proceeds of approximately $44 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 809,000 shares of stock in 2005 and recorded compensation expense of $25.7 million in 2005 related to the restricted stock and options.

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 invested approximately $148.9 million in total capital in 2004 compared to $83.3 million in 2003.

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

For the first nine months of 2006, our production averaged 144 MMcf of natural gas per day and approximately 9,300 barrels of oil per day, or a total of approximately 200 MMcfe per day. Natural gas production comprised approximately 72% of total production for the nine months ended September 30, 2006 compared to approximately 64% for the comparable period in 2005. This increase in the gas to oil ratio primarily resulted from the acquisition of the Forest Gulf of Mexico operations. Production continued to be adversely affected by the 2005 hurricane season, resulting in shut-in production and startup delays. We estimate that as of September 30, 2006, approximately 12 MMcfe per day of production remained shut-in and approximately 33 MMcfe per day of production had recommenced since June 30, 2006. The four deepwater projects that experienced startup delays have recommenced production. As a result of ongoing repairs to pipelines, facilities, terminals and host facilities, we expect most of the remaining shut-in production to recommence by the end of 2006 and the balance in 2007, except that an immaterial amount of production is not expected to recommence.

Our production for 2005 averaged approximately 50 MMcf of natural gas per day and approximately 4,900 barrels of oil per day, or a total of approximately 80 MMcfe per day. Natural gas production comprised approximately 63% of total production in 2005 and 2004.

In the last two quarters of 2005 our production was negatively impacted by Hurricanes Katrina and Rita. Production shut-in and deferred because of the hurricanes impact totaled approximately 6-8 Bcfe during the last two quarters of 2005. As of December 31, 2005 approximately 5 MMcfe per day of production remained shut-in awaiting repairs, primarily associated with our Baccarat property, which was brought back on-line in January 2006. While we believe physical damage to our existing platforms and facilities was relatively minor from both hurricanes, the effects of the storms caused damage to onshore pipeline and processing facilities that resulted in a portion of our production being temporarily shut-in, or in the case of our Viosca Knoll 917 (Swordfish) project, postponed until the fourth quarter of 2005. In addition, Hurricane Katrina caused damage to platforms that host three of our development projects: Mississippi Canyon 718 (Pluto), Mississippi Canyon 296 (Rigel), and Mississippi Canyon 66 (Ochre). Our Rigel project recommenced production in the first quarter of 2006, and our Pluto and Ochre projects recommenced production in the third quarter of 2006.

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. In September 2004, Mariner 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. It subsequently has been shut-in since Hurricane Katrina, with production expected to recommence in the first quarter of 2007 after completion of host platform repairs. Production from Mississippi Canyon 66 (Ochre) recommenced in the third quarter of 2006, producing at about the same net rate of approximately 6.5 MMcfe per day as it was immediately prior to Hurricane Ivan.

Historically, a majority of our total production has been comprised of natural gas. We anticipate that our acquisition of the Forest Gulf of Mexico operations will increase our concentration in natural gas production. 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 commenced production at our Green Canyon 178 (Baccarat) project in the third quarter of 2005. However, damage sustained by the host facility during Hurricane Rita caused production to be shut-in. Production recommenced in January 2006. We recommenced production at our Swordfish project in the fourth quarter of 2005, at our Rigel project in the first quarter of 2006 and at our Pluto project in the third quarter of 2006. Production recommenced in October 2006 at our Ewing Banks 921

(North Black Widow) project. Uncertainties, including scheduling, weather, and construction lead times, could cause further delays in the start-up of any one of the projects.

Oil and Gas Property Costs

Of the total $517.0 million of capital expenditures incurred in the first nine months of 2006, approximately $264.9 million or 51% related to development activities (of which about $39.5 million was onshore), $169.1 million or 33% related to exploration activities, including the acquisition of leasehold and seismic, and the balance of approximately $83.0 million or 16% related to the West Cameron 110/111 acquisition, capitalized expenses and minor corporate items.

In 2005, we incurred approximately $242.6 million in capital costs related to property acquisitions, exploration, and development activities and approximately $10.1 million for capital costs associated with the installation of our Aldwell unit gathering system and other minor corporate items. Of the total $252.7 million of capital expenditures incurred in 2005, approximately 51% related to development activities and capitalized overhead and interest, 24% for exploration activities, including the acquisition of leasehold and seismic, 21% for property acquisitions, and the balance was associated with the Aldwell Unit gathering system and minor corporate items. Of the $121.7 million incurred on development activities and capitalized overhead and interest, approximately 27% were for onshore operations, 69% for deep water operations, and 4% for shelf Gulf of Mexico operations. Expenditures for property acquisitions included $46.1 million for assets located in West Texas and $7.9 million to acquire additional interests in offshore Gulf of Mexico projects.

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 expenditures for exploration activities relate to offshore projects, and approximately 30% of exploration capital expended during 2004 was for leasehold, seismic, and geological and geophysical costs. We incurred approximately $47.9 million of exploration capital expenditures in 2004.

Oil and Gas Reserves

We have maintained our reserve base through exploration and exploitation activities despite selling 44.4 Bcfe of our reserves in 2002. Historically, we have not acquired significant reserves through acquisition activities; however, in 2005, we acquired 93.9 Bcfe of estimated proved reserves primarily in West Texas. In March 2006, we acquired estimated proved reserves of 306.1 Bcfe as a result of the merger with Forest Energy Resources. As of December 31, 2005, Ryder Scott estimated our net proved reserves at approximately 337.6 Bcfe, with a PV10 of approximately $1.3 billion and a standardized measure of discounted future net cash flows attributable to our estimated proved reserves of approximately $906.6 million. Please see Estimated Proved Reserves for a definition of PV10 and a reconciliation of PV10 to the standardized measure of discounted future net cash flows and for more information concerning our reserve estimates.

Development activities and acquisitions in West Texas and Gulf of Mexico deepwater divestitures have significantly changed our reserve profile since 2002. Proved reserves as of December 31, 2005 were comprised of 61% West Texas, 6% Gulf of Mexico shelf and 33% Gulf of Mexico deepwater compared to 33% West Texas, 19% Gulf of Mexico shelf and 48% Gulf of Mexico deepwater as of December 31, 2002. Proved undeveloped reserves were approximately 50% of total proved reserves as of December 31, 2005. Approximately 25% of proved undeveloped reserves were related to our West Texas Aldwell Unit, where we had 100% development drilling success on 170 wells from 2002 through 2005. Pro forma for the merger transaction, as of December 31, 2005, we had approximately 644 Bcfe of proved reserves, of which 32% were in West Texas, 49% in the Gulf of Mexico shelf and 19% in the Gulf of Mexico deepwater. Proved undeveloped reserves were approximately 44% of total proved reserves as of

December 31, 2005 on a pro forma basis.

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Since December 31, 1997, we have added proved undeveloped reserves attributable to 13 deepwater projects. As of December 31, 2005, ten of those projects 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 579 (Falcon)	66.8	2001	2002 (50% of Mariner s interest sold) 2003 (all of Mariner s remaining interest sold)
Viosca Knoll 917 (Swordfish)	13.4	2001	2005 (100% converted to proved developed)
Green Canyon 178 (Baccarat)	4.0	2004	2005 (100% converted to proved developed)
Mississippi Canyon 296/252 (Rigel)	22.4	2003	2005 (75% converted to proved developed/25% remains undeveloped)

(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, 2005, 8.9 Bcfe of our net proved reserves attributable to this project were classified as proved behind pipe reserves. Production from Pluto recommenced in the third quarter of 2006.

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

Property	**Net Proved Undeveloped Reserves (Bcfe)(1)**	**Year Added**	**Year Expected to Convert to Proved Developed Status**
Green Canyon 646 (Daniel Boone)	16.4	2003	2008
Atwater Valley 380/381/382/425/426 (Bass Lite)	32.3	2005	2008
Ewing Bank 921 (North Black Widow)	3.7	2005	2006

(1) Net proved undeveloped reserves attributable to the project as of December 31, 2005.

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.

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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, the cash losses on contracts settled for natural gas and oil produced during the nine-month period ended September 30, 2006 was $8.3 million. An $8.3 million non-cash gain was also recorded for the nine-month period ended September 30, 2006 relating to the hedges acquired through the Forest transaction. Additionally, an unrealized gain of $1.4 million was recognized for the nine-month period ended September 30, 2006 related to the ineffective portion of open contracts that were not eligible for deferral under SFAS 133 due primarily to the basis differentials between the contract price, which is NYMEX-based for oil and Henry Hub-based for gas, and the indexed price at the point of sale. We incurred cash hedging losses of $53.8 million in 2005, of which $4.5 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 September 30, 2006, December 31, 2005 or December 31, 2004.

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. Additionally, in accordance with purchase price accounting implemented at the time of the Forest transaction, we recorded the mark-to-market liability of Forest Energy Resources hedge contracts as of March 2, 2006 totaling $17.5 million. As of December 31, 2005, the amount of our mark-to-market hedge liabilities totaled $63.8 million and at September 30, 2006 our mark to market assets totaled $73.9 million. See Liquidity and Capital Resources Commodity Prices and Related Hedging Activities.

For the nine months ended September 30, 2006, assuming a totally unhedged position, our price sensitivity for year-to-date revenues for a 10% change in average oil prices and average gas prices received is approximately $15.7 million and $27.7 million, respectively. For the year ended December 31, 2005, assuming a totally unhedged position, our price sensitivity for 2005 net revenues for a 10% change in average oil prices and average gas prices received is approximately $9.3 million and $15.3 million, respectively. For the year ended December 31, 2004, assuming a totally unhedged position, our price sensitivity for 2004 historical net revenues for a 10% change in average oil prices and average gas prices received is approximately $8.9 million and $14.5 million, respectively.

Operating Costs

We classify our operating costs as lease operating expense, transportation expense, and general and administrative expenses. Lease operating expenses are comprised of those costs and expenses necessary to produce oil and gas after an individual well or field has been completed and prepared for production. These costs include direct costs such as field operations, general maintenance expenses, work-overs, and the costs associated with production handling agreements for most of our deepwater fields. Lease operating expenses also include indirect costs such as oil and gas property insurance and overhead allocations in accordance with joint operating agreements.

Severance and ad valorem taxes are comprised of severance, production and ad valorem taxes and are generally variable costs based on production, except for ad valorem taxes.

Transportation costs are generally variable costs associated with transportation of product to sales meters from the wellhead or field gathering point. General and administrative include employee compensation costs (including stock compensation expense), the costs of third party consultants and professionals, rent and other costs of leasing and maintaining office space, the costs of maintaining computer hardware and software, and insurance and other items.

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.

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues (which excludes future cash outflows associated with settlement of asset retirement obligations), discounted at 10% per annum, plus the lower of cost or fair value of unproved properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date.

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. We use derivative financial instruments that qualify for cash flow hedge accounting under SFAS 133, Accounting for Derivative Instruments and Hedging Activities to hedge against the volatility of natural gas prices and, in accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. At September 30, 2006, the effects of the cash flow hedges impacted the ceiling test by $209.0 million. Without the hedges, a write-down of the carrying value of the full cost pool of $125.3 million on a pre-tax basis would have been indicated. On an after-tax basis, the write-down would have been $81.5 million.

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Proved Reserves

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

Compensation Expense

As a result of the adoption of SFAS Statement No. 123(R), we record compensation expense for the fair value of restricted stock and stock options that are granted. In general, compensation expense will be determined at the date of grant based on the fair value of the stock or options granted. The fair value then will be amortized to compensation expense over the applicable vesting periods.

Revenue Recognition

We use the entitlements method of accounting for the recognition of natural gas and oil revenues. Under this method of accounting, income is recorded based on our net revenue interest in production or nominated deliveries. We incur production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Production imbalances are marked-to-market at the end of each month at the lowest of (i) the price in effect at the time of production; (ii) the current market price; or (iii) the contract price, if a contract is in hand.

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. In May 2006, the State of Texas enacted substantial changes to its tax structure beginning in 2007 by implementing a new margin tax of 1% to be imposed on revenues less certain costs, as specified in the legislation. During the second quarter of 2006, we increased our provision by an additional $1.3 million to provide for deferred taxes to the State of Texas under the newly enacted margin tax.

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.

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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.

Mariner 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 Accumulated Other Comprehensive Income (AOCI) as appropriate, until recognized as operating income as the physical production hedged by the contracts is delivered.

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

The conditions to be met for a derivative instrument to qualify as a cash flow hedge are the following: (i) the item to be hedged exposes Mariner 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 the consolidated 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 dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Our most significant financial estimates are based on remaining proved natural gas and oil reserves. Estimates of proved reserves are key components of our depletion rate for natural gas and oil properties, our unevaluated properties and our full cost ceiling test. In addition, estimates are used in computing taxes, preparing accruals of operating costs and production revenues, asset retirement obligations, fair value and effectiveness of derivative instruments and fair value of stock options and the related compensation expense. Because of the inherent nature of the estimation process, actual results could differ materially 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, see Production.

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Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Operating and Financial Results for the Nine Months Ended September 30, 2006 Compared to the Nine Months Ended September 30, 2005

	For the Nine-Month Period Ended September 30,	
Summary Operating Information:	**2006**	**2005**
Net Production:		
Oil (MBbls)	2,534	1,336
Natural Gas (MMcf)	39,298	14,508
Total (MMcfe)	54,503	22,521
Average daily production (MMcfe/d)	200	82
Average sales prices:		
Oil (per Bbl)(1)	$ 59.58	$ 40.12
Natural gas (per Mcf)(1)	7.25	6.54
Total natural gas equivalent ($/Mcfe)(1)	8.00	6.59
Oil and gas revenues:		
Oil sales(1)	$ 150,982	$ 53,579
Gas sales(1)	285,008	94,913
Total oil and gas revenues(1)	435,990	148,492
Other revenues	2,401	2,753
Lease operating expenses	62,863	17,678
Severance and ad valorem taxes	5,710	2,492
Transportation expenses	4,031	1,697
Depreciation, depletion and amortization	192,222	43,457
General and administrative expenses	25,050	26,726
Impairment of production equipment held for use		498
Net interest expense	25,906	4,720
Income before taxes	122,609	53,977
Provision for income taxes	44,385	18,414
Net income	78,224	35,563

(1) Includes the effects of hedging

Production: Production for the first nine months of 2006 averaged 200 MMcfe per day (54.5 Bcfe total for the period) compared to average daily production of 82 MMcfe per day for the first nine months of 2005 (22.5 Bcfe total for the period). The increased production levels for the nine months ended September 30, 2006 resulted primarily from the acquisition of the Forest Gulf of Mexico operations. The first nine months of 2006 continued to be adversely effected by the 2005 hurricane season, resulting in shut-in production and startup delays. We estimate that as of September 30, 2006, approximately 12 MMcfe per day of production remained shut-in and approximately 33 MMcfe per day of production had recommenced since June 30, 2006. The four deepwater projects that experienced startup delays have recommenced production. As a result of ongoing repairs to pipelines, facilities, terminals and host facilities, we expect most of the remaining shut-in production to recommence by the end of 2006 and the balance in 2007, except that an immaterial amount of production is not expected to recommence.

Production in the Gulf of Mexico increased 167% to 47.7 Bcfe from 17.9 Bcfe for the nine-month periods ended September 30, 2006 and 2005, respectively, while onshore production increased 46% to 6.8 Bcfe from 4.7 Bcfe for the nine-month periods ended September 30, 2006 and 2005, respectively. Natural gas production comprised 72% of our total production for the first nine months of 2006 compared to 65% for the first nine months of 2005. The increase in the gas-to-oil ratio was primarily the result of the acquisition of the Forest Gulf of Mexico operations.

Oil and gas revenues: Total oil and gas revenues increased 194% to $436.0 million for the nine-month period ended September 30, 2006 compared to $148.5 million for the nine-month period ended September 30, 2005. Natural gas revenues were $285.0 million and $94.9 million for the nine-month periods ended September 30, 2006 and 2005, respectively. Total oil revenues for the nine-month period ended September 30, 2006 were $151.0 million, compared to $53.6 million for the nine-month period ended September 30, 2005.

Natural gas prices (excluding the effects of hedging) for the first nine months of 2006 averaged $7.05/Mcf compared to $7.23/Mcf for the comparable period of 2005. Oil prices (excluding the effects of hedging) for the first nine months of 2006 averaged $62.13/Bbl compared to $50.17/Bbl for the comparable period of 2005. For the first nine months of 2006, hedges increased average natural gas pricing by $0.20/Mcf to $7.25/Mcf and reduced average oil pricing by $2.55/Bbl to $59.58/Bbl, resulting in a net recognized hedging gain of $1.5 million.

The cash activity on contracts settled for natural gas and oil produced during the nine-month period ended September 30, 2006 was an $8.3 million loss. An $8.3 million non-cash gain was also recorded for the nine-month period ended September 30, 2006 relating to the hedges acquired through the Forest Energy Resources merger. Additionally, an unrealized gain of $1.4 million was recognized for the nine-month period ended September 30, 2006 related to the ineffective portion of open contracts that were not eligible for deferral under SFAS 133 due primarily to the basis differentials between the contract price, which is NYMEX-based for oil and Henry Hub-based for gas, and the indexed price at the point of sale.

Lease operating expenses (including workover expenses) were $62.9 million for the nine-month period ended September 30, 2006 compared to $17.7 million for the nine-month period ended September 30, 2005. The increase primarily was attributable to the consolidation of the Forest Gulf of Mexico operations and increased costs attributable to the addition of new productive wells onshore. Lease operating costs rose to $1.15 per Mcfe for the nine-month period ended September 30, 2006 compared to $0.78 per Mcfe for the nine-month period ended September 30, 2005. Continued shut-in production from the impact of the 2005 hurricanes contributed to the increased per-unit operating costs.

Severance and ad valorem taxes were $5.7 million and $2.5 million for the nine-month periods ended September 30, 2006 and 2005, respectively. The increase was primarily attributable to the consolidation of the Forest Gulf of Mexico operations and the resulting increased production. For the nine-month periods ended September 30, 2006 and 2005, severance and ad valorem taxes were $0.10 and $0.11 per Mcfe, respectively.

Transportation expenses for the nine-month period ended September 30, 2006 were $4.0 million, or $0.07 Mcfe, compared to $1.7 million, or $0.08 per Mcfe, for the nine-month period ended September 30, 2005. The nine-month transportation expenses per Mcfe remained comparable.

Depreciation, depletion, and amortization (DD&A) expense increased 342% to $192.2 million from $43.5 million for the nine-month periods ended September 30, 2006 and 2005, respectively. The increase was a result of increased production due to the consolidation of the Forest Gulf of Mexico operations, as well as an increase in the unit-of-production depreciation, depletion and amortization rate. The rate increased to $3.53 per Mcfe from $1.93 per Mcfe for the nine-month periods ended September 30, 2006 and 2005, respectively. The per unit increase primarily resulted from the increase of offshore production to 88% of total production at September 30, 2006 as compared to 79% at September 30, 2005 because offshore assets have shorter estimated lives. Another factor for the rate increase was increased accretion of asset retirement obligations due to the consolidation of the Forest Gulf of Mexico operations.

General and administrative (G&A) expenses totaled $25.1 million for the first nine months of 2006, compared to $26.7 million for the first nine months of 2005. G&A expense includes charges for stock compensation expense of $9.0 million for the first nine months of 2006 compared to $17.6 million in the first nine months of 2005. For the first nine months of 2006, $6.6 million of compensation expense resulted from amortization of the cost of restricted stock granted at the closing of Mariner s private equity placement in March 2005 and the remaining related to the amortization of new grants issued in 2006 with vesting periods

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of three to four years. The restricted stock related to Mariner s private equity placement was fully vested in May 2006 and there will be no future charges related to those stock grants. The 2005 compensation expense relates solely to the amortization of the restricted stock granted under Mariner s private equity placement. Included in the 2006 G&A expenses are severance, retention, relocation and transition costs related to the acquisition of the Forest Gulf of Mexico operations of $2.6 million for the first nine months of 2006. Salaries and wages in the first nine months of 2006 increased by $11.8 million compared to the same year-earlier period. The increase was primarily the result of staffing additions related to the acquisition of the Forest Gulf of Mexico operations. In addition, the first nine months of 2005 included $2.3 million in payments to our former stockholders to terminate a services agreement. Reported G&A expenses in the first nine months of 2006 are net of $12.2 million of overhead reimbursements billed or received from other working interest owners, compared to $3.1 million for the comparable period of 2005.

Net interest expense increased 449% to $25.9 million from $4.7 million for the nine-month period ended September 30, 2006 and 2005, respectively. This increase was primarily due to an increase in average debt levels to $420.2 million for the nine-month period ended September 30, 2006 from $81.3 million for the nine-month period ended September 30, 2005. The increased debt was primarily the result of the issuance of $300 million of notes, the assumption of debt in the Forest Energy Resources merger and the use of our bank facility to finance capital expenditures in excess of cash flows. Additionally, the amendment and restatement of the credit facility on March 2, 2006 was treated as an extinguishment of debt for accounting purposes, and resulted in a charge of $1.2 million to interest expense.

Income before income taxes increased to $122.6 million from $54.0 million for the nine-month periods ended September 30, 2006 and 2005, respectively. This increase was primarily the result of higher operating income attributed to the Forest Gulf of Mexico operations.

Provision for income taxes had an effective tax rate of 36.2% for the nine months ended September 30, 2006 as compared to an effective tax rate of 34.1% for the comparable period of 2005. The increase in the effective tax rate for the nine months ended September 30, 2006 is primarily a result of the Texas Margins tax, which was enacted during the second quarter of 2006 for all properties residing in Texas. Excluding the effects of the Texas Margins tax, the effective rate would have been 35% for the nine months ended September 30, 2006.

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Year Ended December 31, 2005 compared to Year Ended December 31, 2004

Operating and Financial Results for the Year Ended December 31, 2005
Compared to the Year Ended December 31, 2004

Summary Operating Information:	Non-GAAP Combined Year Ended December 31, 2005	Non-GAAP Combined Year Ended December 31, 2004	Post-Merger Period from March 3, 2004 through December 31, 2004	Pre-Merger Period from January 1, 2004 through March 2, 2004
	(In thousands, except average sales price)			
Net production:				
Oil (MBbls)	1,791	2,298	1,885	413
Natural gas (MMcf)	18,354	23,782	19,549	4,233
Total (MMcfe)	29,100	37,569	30,856	6,713
Average daily production (MMcfe/d)	80	103	101	112
Hedging activities:				
Oil revenues (loss)	$ (18,671)	$ (12,300)	$ (11,614)	$ (686)
Gas revenues (loss)	(30,613)	(7,498)	(8,929)	1,431
Total hedging revenues (loss)	$ (49,284)	$ (19,798)	$ (20,543)	$ 745
Average sales prices:				
Oil (per Bbl) realized(1)	$ 41.23	$ 33.17	$ 33.69	$ 30.75
Oil (per Bbl) unhedged	51.66	38.52	39.86	32.41
Natural gas (per Mcf) realized(1)	6.66	5.80	5.67	6.39
Natural gas (per Mcf) unhedged	8.33	6.12	6.13	6.05
Total natural gas equivalent ($/Mcfe) realized(1)	6.74	5.70	5.65	5.92
Total natural gas equivalent ($/Mcfe) unhedged	8.43	6.23	6.32	5.81
Oil and gas revenues:				
Oil sales	$ 73,831	$ 76,207	$ 63,498	$ 12,709
Gas sales	122,291	137,980	110,925	27,055
Total oil and gas revenues	$ 196,122	$ 214,187	$ 174,423	$ 39,764
Other revenues	3,588			
Lease operating expenses	29,882	25,484	21,363	4,121
Transportation expenses	2,336	3,029	1,959	1,070
Depreciation, depletion and amortization	59,426	64,911	54,281	10,630
General and administrative expenses	37,053	8,772	7,641	1,131
Impairment of production equipment held for use	1,845	957	957	
Net interest expense (income)	7,393	5,734	5,820	(86)
Income before taxes	61,775	105,300	82,402	22,898
Provision for income taxes	21,294	36,855	28,783	8,072
Net income	40,481	68,445	53,619	14,826

(1) Average realized prices include the effects of hedges.

Net production during 2005 decreased approximately 23% to 29.1 Bcfe from 37.6 Bcfe in 2004 primarily due to decreased Gulf of Mexico production, partially offset by increased onshore production. Mariner s production was negatively impacted during the third and fourth quarters of 2005 due to hurricane activity, primarily Katrina and Rita. Production shut-in and deferred because of the hurricanes impact totaled approximately 6-8 Bcfe during the third and fourth quarters of 2005. As of December 31, 2005, approximately

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5 MMcfe per day of production remained shut-in awaiting repairs, primarily associated with our Baccarat property (although, production therefrom recommenced in January 2006). Additionally, production that was anticipated to commence in 2005 at our Swordfish, Ochre, Pluto, and Rigel development projects was delayed awaiting repairs to host facilities. Swordfish recommenced production in the fourth quarter of 2005, Rigel recommenced production in the first quarter of 2006, and Ochre and Pluto recommenced production in the third quarter of 2006.

Increased development drilling at our Aldwell unit in West Texas contributed to a 60% increase in onshore production to an average of approximately 18.1 MMcfe per day in 2005 from an average of approximately 11.3 MMcfe per day in 2004.

In the deepwater Gulf of Mexico, production decreased approximately 32% to an average of approximately 32.3 MMcfe per day in 2005 compared to an average of approximately 47.2 MMcfe per day in 2004. The decrease was largely due to reduced production at our Black Widow, Yosemite 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 and Yosemite was negatively impacted by hurricane activity as well as by expected declines. As previously discussed, hurricane-related delays in commencement of production at our Swordfish, Pluto and Rigel development projects also contributed to the production decline.

In the Gulf of Mexico shelf, production decreased by approximately 34% to an average of approximately 29.2 MMcfe per day in 2005 from an average of approximately 44.1 MMcfe per day in 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 and Hurricanes Katrina and Rita in 2005. Production from three new shelf discoveries (Green Pepper, Royal Flush, and Dice) and production from the 2004 acquisition of interests in five offshore fields offset normal declines at our other Gulf of Mexico shelf fields and the impact of the 2005 hurricane season.

Hedging activities in 2005 decreased our average realized natural gas price received by $1.67 per Mcf and revenues by $30.6 million, compared with a decrease of $0.32 per Mcf and revenues of $7.5 million in 2004. Our hedging activities with respect to crude oil during 2005 decreased the average sales price received by $10.43 per barrel and revenues by $18.7 million compared with a decrease of $5.35 per barrel and revenues of $12.3 million for 2004.

Oil and gas revenues decreased 8% to $196.1 million in 2005 when compared to 2004 oil and gas revenues of $214.2 million, due to the aforementioned 23% decrease in production, partially offset by an 18% increase in realized prices (including the effects of hedging) to $6.74 per Mcfe in 2005 from $5.70 per Mcfe in 2004.

Other revenues of $3.6 million in 2005 represent an indemnity payment of $1.9 million received from our former stockholder related to the 2004 merger and $1.7 million generated by our West Texas Aldwell unit gathering system.

Lease operating expenses increased 17% to $29.9 million in 2005 from $25.5 million in 2004. The increased costs were primarily attributable to the addition of new producing wells at our Aldwell Unit offset by reduced costs on our Black Widow, King Kong/Yosemite, and Pluto deepwater fields. On a per unit basis, lease operating expenses were $1.03 per Mcfe in 2005 compared to $0.68 per Mcfe in 2004. The increased per unit costs also reflect lower production rates in 2005, including hurricane-related disruptions.

Transportation expenses were $2.3 million or $0.08 per Mcfe in 2005, compared to $3.0 million or $0.08 per Mcfe in 2004. The reduction is primarily attributable to our deepwater fields and includes reductions caused by the filing of new and higher transportation allowances with the MMS on two of our deepwater fields for purpose of royalty calculation.

Depreciation, depletion, and amortization (DD&A) expense decreased 8% to $59.4 million during 2005 from $64.9 million for 2004 as a result of decreased production of 8.5 Bcfe in 2005 compared to 2004, partially offset by an increase in the unit-of-production depreciation, depletion and amortization rate to

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$2.04 per Mcfe for 2005 from $1.73 per Mcfe for 2004. The per unit increase was primarily the result of an increase in future development costs on our deepwater development fields.

General and administrative (G&A) expenses, which are net of $6.9 million and $4.4 million of overhead reimbursements billed or received from other working interest owners in 2005 and 2004, respectively, increased 322% to $37.1 million during 2005 compared to $8.8 million in 2004. The increase was primarily due to recognizing $25.7 million in stock compensation expense related to restricted stock and options granted in 2005. We also paid $2.3 million to our former stockholders to terminate a services agreement in 2005, compared to $1.0 million under the same agreement in 2004. In addition, G&A expenses increased by $1.6 million due to a reduction in the amount of G&A capitalized in 2005 compared to 2004.

Impairment of production equipment held for use reflects the reduction of the carrying cost of our inventory by $1.8 million and $1.0 million as of December 31, 2005 and December 31, 2004, respectively. In 2005, the reduction in estimated value primarily related to subsea trees and wellhead equipment held in inventory.

Net interest expense for 2005 increased 25% to $7.4 million from $5.7 million in 2004, primarily due to higher average debt levels in 2005 compared to 2004. In connection with the merger on March 2, 2004, Mariner incurred $135 million in new bank debt and issued a $10 million promissory note to JEDI. For comparison purposes, approximately ten months of interest related to such borrowings is reflected in 2004 compared to twelve months of interest in 2005.

Income before income taxes decreased to $61.8 million for 2005 compared to $105.3 million for 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 and transportation expenses.

Provision for income taxes decreased to $21.3 million for 2005 from $36.9 million for 2004 as a result of decreased operating income for 2005 compared to 2004.

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

Operating and Financial Results for the Year Ended December 31, 2004
Compared to the Year Ended December 31, 2003

Summary Operating Information:	Year Ended December 31, 2003	Non-GAAP Combined Year Ended December 31, 2004	Post-Merger Period from March 3, 2004 through December 31, 2004	Pre-Merger Period from January 1, 2004 through March 2, 2004
	(In thousands, except average sales price)			
Net production:				
Oil (MBbls)	1,600	2,298	1,885	413
Natural gas (MMcf)	23,772	23,782	19,549	4,233

Total (MMcfe)	33,374	37,569	30,856	6,713
Average daily production (MMcfe/d)	91	103	101	112
Hedging activities:				
Oil revenues (loss)	$ (4,969)	$ (12,299)	$ (11,613)	$ (686)
Gas revenues (loss)	(24,494)	(7,498)	(8,929)	1,431
Total hedging revenues (loss)	$ (29,463)	$ (19,797)	$ (20,542)	$ 745

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Summary Operating Information:	Non-GAAP Combined Year Ended December 31, 2003	Non-GAAP Combined Year Ended December 31, 2004	Post-Merger Period from March 3, 2004 through December 31, 2004	Pre-Merger Period from January 1, 2004 through March 2, 2004
	(In thousands, except average sales price)			
Average sales prices:				
Oil (per Bbl) realized(1)	$ 23.74	$ 33.17	$ 33.69	$ 30.75
Oil (per Bbl) unhedged	26.85	38.52	39.85	32.41
Natural gas (per Mcf) realized(1)	4.40	5.80	5.67	6.39
Natural gas (per Mcf) unhedged	5.43	6.12	6.13	6.05
Total natural gas equivalent ($/Mcfe) realized(1)	4.27	5.70	5.65	5.92
Total natural gas equivalent ($/Mcfe) unhedged	5.15	6.23	6.32	5.81
Oil and gas revenues:				
Oil sales	$ 37,992	$ 76,207	$ 63,498	$ 12,709
Gas sales	104,551	137,980	110,925	27,055
Total oil and gas revenue	$ 142,543	$ 214,187	$ 174,423	$ 39,764
Lease operating expenses	24,719	25,484	21,363	4,121
Transportation expenses	6,252	3,029	1,959	1,070
Depreciation, depletion and amortization	48,339	64,911	54,281	10,630
General and administrative expenses	8,098	8,772	7,641	1,131
Impairment of production equipment held for use		957	957	
Net interest expense (income)	6,225	5,734	5,820	(86)
Income before taxes and change in accounting method	45,688	105,300	82,402	22,898
Provision for income taxes	9,387	36,855	28,783	8,072
Net income	38,244	68,445	53,619	14,826

(1) Average realized prices include the effects of hedges.

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.

DD&A 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.

G&A expenses, which are 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.

Liquidity and Capital Resources

Cash Flows and Liquidity

Secured Bank Credit Facility. At December 31, 2005, we had $152 million in advances outstanding under our secured revolving credit facility with a borrowing base as of that date of $170 million. In January 2006, the borrowing base was increased to $185 million. In connection with the merger with Forest Energy Resources on March 2, 2006, we amended and restated our existing credit facility to increase maximum credit availability to $500 million for revolving loans, including up to $50 million in letters of credit, with a $400 million borrowing base as of that date. On March 2, 2006, after giving effect to funds required at closing to refinance $176.2 million of debt assumed in the merger and other merger-related costs, our total debt drawn under the facility was approximately $350 million, including a $4.2 million letter of credit required for plugging and abandonment obligations at one of our offshore fields. On April 7, 2006, the borrowing base under the secured credit facility was increased to $430 million, subject to redetermination or adjustment. On April 24, 2006, the borrowing base was reduced to $362.5 million in accordance with an amendment to the credit facility related to our offering of $300 million of senior notes. For subsequent qualifying bond issuances, the amendment provides that the borrowing base in effect on the closing date of such a bond issuance will automatically reduce by 25% of the aggregate principal amount of such bond issuance to the extent that it does not refinance the principal amount of an existing bond issuance. The secured credit facility permits Mariner s issuance of certain unsecured bonds of up to $350 million in aggregate principal amount that have a non-default interest rate of 10% or less per annum and a scheduled maturity date after March 1, 2012. Mariner s sale and issuance of $300 million of senior notes in April 2006 constituted such a qualifying bond issuance. At September 30, 2006, approximately $328.6 million was outstanding under our revolving secured credit facility, including the $4.2 million letter of credit and a $10.4 million letter of credit issued in August 2006 to BP to secure certain assumed offshore plugging and abandonment obligations. The borrowing base was increased to $450 million in October 2006, subject to redetermination or adjustment. This credit facility matures on March 2, 2010.

The amendment and restatement of our secured credit facility on March 2, 2006 also provided for an additional $40 million letter of credit that is not included as a use of the borrowing base and matures on March 2, 2009. The $40 million letter of credit was issued in favor of Forest to secure Mariner s performance of its obligations to drill and complete 150 wells under an existing drill-to-earn program. This letter of credit will reduce periodically by an amount equal to the product of $0.5 million times the number of wells exceeding 75 that are drilled and completed. The first reduction of approximately $4.3 million occurred in October 2006 based upon the 83 wells drilled and completed as of September 30, 2006. We expect additional reductions based upon quarterly drilling activity, with the next reduction anticipated in January 2007.

Private Placement of Senior Unsecured Notes due 2013. On April 24, 2006, Mariner sold and issued to eligible purchasers $300 million aggregate principal amount of its 71/2% senior notes due 2013 pursuant to Rule 144A under the Securities Act. The notes were priced to yield 7.75% to maturity. Net proceeds, after deducting initial purchasers discounts and commissions and offering expenses, were approximately $287.9 million. Mariner used the net proceeds to repay borrowings under its secured credit facility. The issuance of the notes was a qualifying bond issuance under Mariner s secured credit facility and resulted in an automatic reduction of its borrowing base to $362.5 million as of April 24, 2006. For a description of the terms of the notes, see Description of Senior Notes. Costs associated with the notes offering were approximately $8.3 million, excluding discounts of $3.8 million.

JEDI Term Promissory Note. As part of the 2004 merger consideration payable to JEDI, we issued a term promissory note to JEDI in the amount of $10 million. The note bore 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 remained 10% per annum. We chose to pay the interest in cash rather than in kind. The JEDI note was secured by a lien on three of our Gulf of Mexico properties with no proved reserves. We could offset against the note the amount of certain claims for indemnification that could be asserted against JEDI under the terms of the merger agreement. The JEDI note contained 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 2005 private equity placement to repay a portion of the JEDI note. As of December 31, 2005, $4 million was still outstanding under the JEDI note. This note was repaid in full on its maturity date of March 2, 2006.

Working Capital. Working capital at September 30, 2006 was a negative $75.3 million, excluding current derivative liabilities and deferred taxes. This was a result of increased accrued capital obligations for drilling and development projects in progress. Working capital at December 31, 2005 was negative $46.4 million, excluding current derivative liabilities and deferred taxes. Accrued liabilities (including accounts payable) and accrued receivables (including accounts receivable) at December 31, 2005 increased by approximately 91% and 68%, respectively, over levels at December 31, 2004 primarily due to increased accrued obligations for drilling and development projects in progress at year end 2005 and related accruals of amounts owed by partners. As of December 31, 2004, we had negative working capital of approximately $18.7 million compared to positive working capital of $38.3 million at December 31, 2003, in each case excluding current derivative liabilities and restricted cash. The reduction in working capital from 2003 is primarily the result of a change in the manner Mariner utilizes excess cash. At year end 2003, Mariner 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, Mariner 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.

Capital Expenditures. In the first nine months of 2006, our capital expenditures were approximately $517.0 million, of which approximately 51% related to development activities; 46% related to the acquisition of BP s interest in West Cameron 110/111 and exploration activities, including the acquisition of leasehold and

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seismic; and the balance related to capitalized expenses and minor corporate items. Our 2005 capital expenditures were $252.7 million. Approximately 48% of our capital expenditures were incurred for development projects, 24% for exploration activities, 21% for acquisitions of developed properties, and the remainder for other items (primarily expenditures for our Aldwell gathering system, capitalized overhead and interest). The following table presents major components of our capital expenditures for the nine months ended September 30, 2006 and for each of the three years in the period ended December 31, 2005.

	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Combined Year Ended December 31, 2004	Post-Merger Period from March 3, 2004 to December 31, 2004	Pre-Merger Period from January 1, 2004 to March 2, 2004	Year Ended December 31, 2003
	(In millions)					
Capital expenditures:						
Leasehold acquisition	$ 15.5	$ 11.5	$ 4.8	$ 4.4	$ 0.4	$ 4.8
Oil and natural gas exploration	154.3	50.0	43.0	35.9	7.1	26.8
Oil and natural gas development	264.2	121.7	88.6	82.0	6.6	44.3
Proceeds from property conveyances	(2.0)					(121.6)
Acquisitions	70.9	53.4	4.9	4.9		
Other items (primarily gathering system, capitalized overhead and interest)	12.1	16.1	7.6	6.4	1.2	7.4
Total capital expenditures, net of proceeds from property conveyances	$ 515.0	$ 252.7	$ 148.9	$ 133.6	$ 15.3	$ (38.3)

Our net capital expenditures for 2005 increased by $103.8 million as compared to 2004, primarily as a result of increased acquisitions, primarily in West Texas, and increased expenditures on development activities. 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.

We had no long-term debt outstanding as of December 31, 2003. As of December 31, 2005 and 2004, long-term debt was $156 million and $115 million, respectively. As of September 30, 2006, long-term debt was $614 million.

We anticipate that total capital expenditures for 2006 will approximate $690.0 million (of which approximately $70.9 million is attributable to the West Cameron acquisition described under Recent Developments), with approximately 57% allocated to development activities, 41% to exploration activities, and the remainder to other items (primarily capitalized overhead and interest). The 2006 budget is an increase of approximately 83% over our 2005 expenditures. The increase is primarily driven by the addition of the Forest Gulf of Mexico operations, continuation of our deepwater development activities, and expansion of our exploration activities, including increasing our acquisition of leasehold and seismic data. In addition, we expect to incur approximately $85 million for repairs of damage caused by Hurricanes Katrina and Rita. While this will be a cash outflow in 2006, we expect to recover these costs through insurance reimbursements beginning in early 2007, although complete insurance settlement of all hurricane-related claims may take several additional quarters. See Business Insurance Matters. Since we believe these costs to be reimbursable, they will not be reflected in reported 2006 capital expenditures.

Cash Flows. During the first nine months of 2006, we utilized our secured credit facility to fund amounts for capital expenditures incurred in excess of cash flows. Although we expect to fund exploration and development capital expenditures during the remainder of 2006 from internally generated cash flows, the credit facility may be utilized for such expenditures exceeding current projections and for acquisitions.

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. 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 reduced. If our cash flows are less than anticipated or amounts available for borrowing under our revolving credit facility are reduced or we can not access the high yield or other debt markets, we may be forced to defer planned capital expenditures.

In addition, 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 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.

Our existing proved reserves are comprised of West Texas and Gulf of Mexico properties. The West Texas properties are relatively long-life in nature characterized by relatively low decline rates (lower productive rates) while the Gulf of Mexico properties are shorter-life in nature characterized by relatively high decline rates (higher productive rates). For the year ended December 31, 2005, our Gulf of Mexico properties comprised about 77% of our total production or 93% on a pro forma basis. We plan to maintain an active drilling program for our onshore properties with the intention of maintaining or increasing production in those areas. Although production from our existing offshore wells will decline more rapidly over time than our onshore wells, the percentage of production attributable to our offshore wells is expected to increase in the coming years as more of our undeveloped deep water projects commence production and we begin to exploit our newly acquired offshore assets. While we expect this trend to continue for the near future, oil and gas production (especially for our offshore properties) can be heavily affected by reservoir characteristics and unforeseen events (such as hurricanes and other casualties), so we can not predict with any certainty the timing of declines in production or the commencement of production from new projects.

In conjunction with the March 2004 merger, we established a new credit facility maturing on March 2, 2007 that subsequently was amended and restated. The new credit facility was fully drawn at inception for $135 million. In addition, we issued a $10 million promissory note to JEDI as part of the merger consideration. See Enron Related Matters and JEDI Term Promissory Note. Net proceeds from a private equity placement were approximately $44 million, of which $6 million was used to pay down the JEDI promissory note with the remainder used to pay down the credit facility. The JEDI note was fully repaid at its maturity date of March 2, 2006.

For the years ended December 31, 2005 and 2004, our interest rate sensitivity for a change in interest rates of 1/8 percent on average outstanding debt under our credit facility is approximately $0.1 million and $0.1 million, respectively. The LIBOR rate on which our bank borrowings are primarily based was 4.69% as of March 2, 2006.

We had net cash inflows of $0.3 million and $2.0 million for the nine-month periods ended September 30, 2006 and 2005, respectively, and a net cash inflow of $2.0 million in 2005 compared to a net cash outflow of $57.6 million in

2004 and a net cash inflow of $41.8 million in 2003. A discussion of the major components of cash flows for these periods follows.

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	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005	Year Ended December 31, 2005	Non-GAAP Combined Year Ended December 31, 2004	Post-Merger Period from March 3, 2004 to December 31, 2004	Pre-Merger Period from January 1, 2004 to March 2, 2004	Pre-Merger Year Ended December 31, 2003
				(In millions)			
Cash flows provided by operating activities	$ 172.8	$ 135.4	$ 165.4	$ 155.5	$ 135.2	$ 20.3	$ 88.9

Net cash flows from operations increased by $37.4 million to $172.8 million from $135.4 million for the nine-month periods ended September 30, 2006 and 2005, respectively. The increase was primarily due to increased operating revenues attributable to the Forest Gulf of Mexico operations acquired.

Cash flows provided by operating activities in 2005 increased by $9.9 million compared to 2004. The increase was primarily due to negative changes in working capital offset by lowered operating revenues. Cash flows provided by operating activities in 2004 increased by $66.6 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 Mariner.

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005	Year Ended December 31, 2005	Non-GAAP Combined Year Ended December 31, 2004	Post-Merger Period from March 3, 2004 to December 31, 2004	Pre-Merger Period from January 1, 2004 to March 2, 2004	Pre-Merger Year Ended December 31, 2003
				(In millions)			
Cash flows (used in) provided by investing activities	$ (423.5)	$ (142.1)	$ (247.8)	$ (148.3)	$ (133.0)	$ (15.3)	$ 52.9

Net cash flows used for investing activities increased to $423.5 million from $142.1 million for the nine-month periods ended September 30, 2006 and 2005, respectively, due to increased capital expenditures of $117.4 million primarily related to our King Kong and Pluto deepwater projects as well as development drilling in our West Texas fields, and the $70.9 million acquisition of BP s interests in West Cameron 110/111.

Cash flows used in investing activities in 2005 increased by $99.5 million compared to 2004 due to increased capital expenditures in 2005. Cash flows used in investing activities in 2004 increased by $201.2 million compared to 2003 due to increased capital expenditures in 2004 and the sale of assets in prior years.

	Post-Merger	Pre-Merger

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005	Year Ended December 31, 2005	Non-GAAP Combined 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
	(In millions)						
Cash flows (used in) provided by financing activities	$ 251.0	$ 8.7	$ 84.4	$ (64.9)	$ (64.9)		$ (100.0)

Net cash provided by financing activities was $251.0 million for the nine-month period ended September 30, 2006 compared to net cash provided by financing activities of $8.7 million for the same period in 2005. Financings in 2006 were primarily used to fund the Forest transaction and capital expenditures in excess of current cash flows. Mariner also paid the remaining balance of the JEDI term note on March 2, 2006.

Cash flows provided by financing activities in 2005 were primarily the result of proceeds from a private equity offering in March 2005 ($44 million) and net borrowings under our revolving credit facility ($47 million). 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.

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Commodity Prices and Related Hedging Activities

The energy markets have historically been very volatile, and we can reasonably expect that oil and gas prices will be subject to wide fluctuations in the future. If 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. In addition, forward price curves and estimates of future volatility are used to assess and measure the ineffectiveness of our open contracts at the end of each period. If open contracts cease to qualify for hedge accounting, the mark to market change in fair value is recognized in the income statement. Loss of hedge accounting and cash flow designation will cause volatility in earnings. The fair values we report in our financial statements change as estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

As of September 30, 2006, Mariner had the following hedge contracts outstanding:

Fixed Price Swaps	**Quantity**	**Fixed Price**	**September 30, 2006 Fair Value Gain/(Loss) (In millions)**
Crude Oil (Bbls)			
October 1 December 31, 2006	644,920	$ 72.24	$ 5.1
Natural Gas (MMbtus)			
October 1 December 31, 2006	9,315,000	7.97	20.9
January 1 December 31, 2007	15,846,323	9.68	31.7
January 1 September 30, 2008	3,059,689	9.58	4.3
Total			$ 62.0

Costless Collars	**Quantity**	**Floor**	**Cap**	**September 30, 2006 Fair Value Gain/(Loss) (In millions)**
Crude Oil (Bbls)				
October 1 December 31, 2006	63,480	$ 32.65	$ 41.52	$ (1.4)
January 1 December 31, 2007	2,032,689	59.84	84.21	(1.0)
January 1 December 31, 2008	1,195,495	61.66	86.80	2.7
Natural Gas (MMbtus)				
October 1 December 31, 2006	1,851,960	5.78	7.85	0.9
January 1 December 31, 2007	14,106,750	6.87	11.82	1.7
January 1 December 31, 2008	12,347,000	7.83	14.60	9.1

Total	$ 12.0

As of December 31, 2005, Mariner had the following hedge contracts outstanding:

Fixed Price Swaps	**Quantity**	**Fixed Price**	**December 31, 2005 Fair Value Gain/(Loss) (In millions)**
Crude Oil (Bbls)			
January 1 December 31, 2006	140,160	$ 29.56	(4.7)
Natural Gas (MMBtus)			
January 1 December 31, 2006	1,827,547	5.53	(9.9)
Total			$ (14.6)

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Costless Collars		Quantity	Floor	Cap	December 31, 2005 Fair Value Gain/(Loss) (In millions)
Crude Oil (Bbls)					
January 1	December 31, 2006	251,850	$ 32.65	$ 41.52	(5.3)
January 1	December 31, 2007	202,575	31.27	39.83	(4.7)
Natural Gas (MMBtus)					
January 1	December 31, 2006	7,347,450	5.78	7.85	(22.3)
January 1	December 31, 2007	5,310,750	5.49	7.22	(16.9)
Total					$ (49.2)

As of December 31, 2004, Mariner 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)

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)

As of November 3, 2006, there were no hedging transactions entered into subsequent to September 30, 2006.

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 September 30, 2006, December 31, 2005 and December 31, 2004, we had no deposits for collateral with our counterparties.

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

	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	2004	2003
		(Dollars in millions)		
Natural Gas				
Quantity settled (MMBtus)	19,378,000	15,917,159	18,823,063	25,520,000
Increase/(Decrease) in Natural Gas Sales	$ 5.0	$ (33.0)	$ (10.8)	$ (27.1)
Crude Oil				
Quantity settled (Mbbls)	937	836	1,554	730
Decrease in Crude Oil Sales	$ (6.5)	$ (20.8)	$ (16.9)	$ (5.0)

The cash losses on contracts settled for natural gas and oil produced during the nine-month period ended September 30, 2006 was $8.3 million. An $8.3 million non-cash gain was recorded for the nine-month period ended September 30, 2006 relating to the hedges acquired through the Forest transaction. Additionally, an unrealized gain of $1.4 million was recognized for the nine-month period ended September 30, 2006 related to the ineffective portion of open contracts that were not eligible for deferral under SFAS 133 due primarily to the basis differentials between the contract price, which is NYMEX-based for oil and Henry Hub-based for gas, and the indexed price at the point of sale. 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 years ended December 31, 2005 and 2004, $4.5 million and $7.9 million, respectively, of the $53.8 million and $27.7 million total decrease in natural gas and oil sales, respectively, of cash hedge losses relate to the liability recorded at the time of the merger.

Interest Rate Hedges

Borrowings under our revolving credit facility, discussed above, mature on March 2, 2010, 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. For the nine-month period ended September 30, 2006, the interest rate on our outstanding bank debt averaged 7.16%. If the balance of our bank debt at September 30, 2006 were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $0.4 million per quarter or $1.1 million for the nine-month period ended September 30, 2006.

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 September 30, 2006:

	Total	Less Than One Year	1-3 Years	3-5 Years	More Than 5 Years

	(In millions)				
Debt obligations(1)	$ 614.0	$	$	$ 314.0	$ 300.0
Interest obligations(2)	155.1	28.1	45.0	45.0	37.0
Operating leases	7.6	1.5	2.4	1.3	2.4
Abandonment liabilities	222.5	52.0	41.1	43.8	85.6
Derivative financial instruments	(74.0)	(55.3)	(18.7)		
Other liabilities	243.1	237.1	6.0		
Total contractual cash commitments	$ 1,168.3	$ 263.4	$ 75.8	$ 404.1	$ 425.0

(1) As of September 30, 2006, we had incurred debt obligations under our secured credit facility and the senior unsecured notes that are due on March 2, 2010 and April 15, 2013, respectively.

(2) Interest obligations represent interest due on the senior unsecured notes at 7.5%. Future interest obligations under our credit facility are uncertain, due to the variable interest rate on fluctuating balances. Based on a 8.0% weighted average interest rate on amounts outstanding under our amended and restated credit facility as of September 30, 2006, $25.1 million, $50.2 million and $13.6 million would be due under the credit facility in less than one year, 1-3 years and 3-5 years, respectively.

Certain MMS Leases. Each of Mariner and its subsidiary, Mariner Energy Resources, Inc., owns numerous properties in the Gulf of Mexico. Certain of these 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 leases until a designated volume is produced. Two of these leases held by Mariner and one held by its subsidiary contained language that limited royalty relief if commodity prices exceeded predetermined levels. Since 2000, commodity prices have exceeded the predetermined levels, except in 2002. Mariner and its subsidiary believe the MMS did not have the authority to set pricing limits in these leases and have withheld payment of royalties on the leases while disputing the MMS authority in two pending proceedings. Mariner has recorded a liability for 100% of the exposure on its two leases, which at September 30, 2006 was $19.9 million. Various legal proceedings are pending concerning this potential liability and further proceedings may be initiated with respect to years not covered by the pending proceedings. In April 2005, the MMS denied Mariner s administrative appeal of the MMS April 2001 order asserting royalties were due because price limits had been exceeded. In October 2005, Mariner filed suit in the U.S. District Court for the Southern District of Texas seeking judicial review of the dismissal. Upon motion of the MMS, Mariner s lawsuit was dismissed on procedural grounds. In August 2006, Mariner filed an appeal of such dismissal. Mariner had also filed an administrative appeal of a December 2005 order of the MMS demanding royalties for calendar year 2004 under the same leases at issue in the April 2001 MMS order. However, the MMS withdrew such order, rendering the appeal moot. Thereafter, in May 2006, the MMS issued an order asserting price limits were exceeded in calendar years 2001, 2003 and 2004 and, accordingly, that royalties were due under such leases on oil and gas produced in those years. Mariner has filed and is pursuing an administrative appeal of that order.

The potential liability of Mariner Energy Resources, Inc. under its lease subject to the RRA containing such commodity price threshold language is approximately $2.2 million as of September 30, 2006. This potential liability relates to production from the lease commencing July 1, 2005, the effective date of Mariner s acquisition of Mariner Energy Resources, Inc. A reserve for this possible liability will be made when deemed appropriate. The MMS has not yet made demand for non-payment of royalties alleged to be due for calendar years subsequent to 2004 on the basis of price thresholds being exceeded.

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, Mariner 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, this no longer is an off-balance sheet arrangement.

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Letters of Credit On March 2, 2006, Mariner obtained a $40 million letter of credit under its senior secured letter of credit facility. The letter of credit was issued in favor of Forest to secure performance of our obligation to drill and complete 150 wells under an existing drill-to-earn program and is not included as a use of the borrowing base of the senior secured credit facility. This letter of credit will reduce periodically by an amount equal to the product of $0.5 million times the number of wells exceeding 75 that are drilled and completed. The first reduction of approximately $4.3 million occurred in October 2006 based upon the 83 wells drilled and completed as of September 30, 2006. Mariner expects additional reductions based upon quarterly drilling activity, with the next reduction anticipated in January 2007.

Mariner s senior secured credit facility also has a letter of credit facility of up to $50 million that is included as a use of the borrowing base. As of September 30, 2006, two such letters of credit for $4.2 million and $10.4 million were outstanding. These two letters of credit are required for plugging and abandonment obligations at certain of Mariner s offshore fields.

Recent Accounting Pronouncements

In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty.* EITF Issue 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. We do not expect the adoption of this EITF Issue to have a material impact on our consolidated financial position, results of operations or cash flows.

In July 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes.* FIN No. 48 clarifies SFAS No. 109, *Accounting for Income Taxes*, and requires us to evaluate our tax positions for all jurisdictions and all years where the statute of limitations has not expired. FIN No. 48 requires companies to meet a more-likely-than-not threshold (i.e. greater than a 50 percent likelihood of being sustained under examination) prior to recording a benefit for their tax positions. Additionally, for tax positions meeting this more-likely-than-not threshold, the amount of benefit is limited to the largest benefit that has a greater than 50 percent probability of being realized upon ultimate settlement. The cumulative effect of applying the provisions of the new interpretation will be recorded as an adjustment to the beginning balance of retained earnings, or other components of stockholders equity, as appropriate, in the period of adoption. We will adopt the provisions of this interpretation effective January 1, 2007, and are currently evaluating the impact, if any, that this interpretation will have on our financial statements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which establishes guidelines for measuring fair value and expands disclosures regarding fair value measurements. SFAS No. 157 does not require any new fair value measurements but rather it eliminates inconsistencies in the guidance found in various prior accounting pronouncements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. Earlier adoption is encouraged, provided the company has not yet issued financial statements, including for interim periods, for that fiscal year. Although we are still evaluating the potential effects of this standard, we do not expect the adoption of SFAS No. 157 to have a material impact on our consolidated financial position, results of operation, or cash flows.

In September 2006, the Securities and Exchange Commission released Staff Accounting Bulletin No. 108, Quantifying Financial Statement Misstatements (SAB 108). SAB 108 gives guidance on how errors, built up over time in the balance sheet, should be considered from a materiality perspective and corrected. SAB 108 provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. SAB 108 represents the SEC Staff s views on the proper interpretation of existing rules and as such has no effective date. We do not expect the adoption of SAB 108 to have a material impact on our consolidated financial position, results of operation, or cash flows.

In June 2006, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 06-03, How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation) . EITF 06-03 requires that companies disclose the

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gross amounts of taxes reported. The consensus is effective for interim or annual reporting periods beginning after December 15, 2006. We do not expect the adoption of this EITF issue to have a material impact on our consolidated financial position, results of operations or cash flows.

BUSINESS

Mariner Energy, Inc. is an independent oil and gas exploration, development and production company with principal operations in the Gulf of Mexico, both shelf and deepwater, and in West Texas. Our management has significant expertise and a successful operating track record in these areas. In the three-year period ended December 31, 2005, we added approximately 280 Bcfe of proved reserves and produced approximately 100 Bcfe, while deploying approximately $475 million of capital on acquisitions, exploration and development.

Our primary operating strategy is to generate high-quality exploration and development projects, which enables us to add value through the drill bit. Our expertise in project generation also facilitates our participation in high-quality projects generated by other operators. We will also pursue acquisitions of producing assets that have the potential to provide acceptable risk-adjusted rates of return and further reserve additions through exploration, exploitation, and development opportunities. We target a balanced exposure to development, exploitation and exploration opportunities, both offshore and onshore and seek to maintain a moderate risk profile.

On March 2, 2006, we completed a merger transaction with Forest Energy Resources, Inc., which we refer to as Forest Energy Resources. As a result of this merger, we acquired the Gulf of Mexico operations of Forest Oil Corporation (NYSE: FST), which we refer to as the Forest Gulf of Mexico operations. As of December 31, 2005, we had 338 Bcfe of estimated proved reserves, of which approximately 62% were natural gas, and 38% were oil and condensate, and 50% of which was proved developed. Pro forma for the merger transaction, as of December 31, 2005, we had 644 Bcfe of estimated proved reserves, of which approximately 68% were natural gas and 32% were oil and condensate, and 56% of which was proved developed.

Our production for 2005 was approximately 29 Bcfe, or 80 MMcfe per day on average, and 95 Bcfe, or 260 MMcfe per day on average, pro forma for the merger. During the year ended December 31, 2005, our pro forma EBITDA was approximately $438.6 million, including $25.7 million of non-cash compensation expense related to restricted stock and stock options granted in 2005, but excluding general and administrative expenses of the Forest Gulf of Mexico operations. Our production for the nine months ended September 30, 2006 was approximately 55 Bcfe, or 200 MMcfe per day on average, and pro forma for the merger, 62 Bcfe, or 229 MMcfe per day on average. During the nine months ended September 30, 2006, our EBITDA was approximately $340.7 million, and pro forma for the merger, approximately $391.7 million, in each case, including a $9.0 million reduction for non-cash compensation expense related to restricted stock and stock options. We believe the overhead costs associated with the Forest Gulf of Mexico operations in 2006 will be approximately $6.4 million, net of capitalized amounts. See footnote 1 on page 13 for our definition of EBITDA and a reconciliation of net income to EBITDA.

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The following table sets forth certain information with respect to our estimated proved reserves, production and acreage by geographic area as of December 31, 2005. Reserve volumes and values were determined under the method prescribed by the SEC which requires the application of period-end prices and costs held constant throughout the projected reserve life. Proved reserve estimates do not include any value for probable or possible reserves which may exist, nor do they include any value for undeveloped acreage. The proved reserve estimates represent our net revenue interest in our properties. The reserve information for Mariner as of December 31, 2005 is based on estimates made in a reserve report prepared by Ryder Scott.

	Estimated Proved Reserve Quantities				Production for Year Ended December 31 2005
	Oil (MMbbls)	Natural Gas (Bcf)	Total (Bcfe)	Total Net Acreage	(Natural Gas Equivalent (Bcfe))
West Texas	16.7	105.5	205.5	31,199	6.6
Gulf of Mexico Deepwater(1)	4.7	83.2	111.1	185,271	11.8
Gulf of Mexico Shelf(2)	0.3	19.0	21.0	124,180	10.7
Total	21.7	207.7	337.6	340,650	29.1
Proved Developed Reserves	9.6	110.0	167.4		

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

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

The following table sets forth certain information with respect to our estimated proved reserves, production and acreage by geographic area on a pro forma basis for our merger with Forest Energy Resources as of December 31, 2005. The reserve information as of December 31, 2005 for the Forest Gulf of Mexico operations is based on estimates made by internal staff engineers of Forest, which estimates were audited by Ryder Scott. This information is presented on a pro forma basis, giving effect to our merger with Forest Energy Resources as though it had been consummated on December 31, 2005. We consummated the merger on March 2, 2006.

	Pro Forma Estimated Proved Reserve Quantities			Total	Pro Forma Production for Year Ended December 31 2005
	Oil (MMbbls)	Natural Gas (Bcf)	Total (Bcfe)	Net Acreage	(Natural Gas Equivalent (Bcfe))

West Texas	16.7	105.5	205.5	31,199	6.6
Gulf of Mexico Deepwater(1)	4.8	95.7	124.5	241,320	14.0
Gulf of Mexico Shelf(2)	12.7	237.6	313.7	652,086	74.3
Total	34.2	438.8	643.7	924,605	94.9
Proved Developed Reserves	18.4	252.1	362.3		

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

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

Forest Gulf of Mexico Merger

On March 2, 2006, we completed a merger transaction with Forest Energy Resources. Prior to the consummation of the merger, Forest transferred and contributed the assets and certain liabilities associated with its Gulf of Mexico operations to Forest Energy Resources. Immediately prior to the merger, Forest distributed all of the outstanding shares of Forest Energy Resources to Forest shareholders on a pro rata basis. Forest Energy Resources then merged with a newly-formed subsidiary of Mariner, became a new wholly-owned subsidiary of Mariner, and changed its name to Mariner Energy Resources, Inc. Immediately following the merger, approximately 59% of Mariner common stock was held by shareholders of Forest and approximately 41% of Mariner common stock was held by the pre-merger stockholders of Mariner.

Forest Energy Resources had approximately 306 Bcfe of estimated proved reserves as of December 31, 2005, of which approximately 76% were natural gas, and 24% were oil and condensate. The reserves and operations acquired from Forest are concentrated in the shelf and deep shelf of the Gulf of Mexico and represent a significant addition to Mariner s asset portfolio in those areas of operation.

We believe our acquisition of the Forest Gulf of Mexico operations and the scale they bring to our business has further moderated our risk profile, provided many exploration, exploitation and development opportunities, enhanced our ability to participate in prospects generated by other operators, and added a significant cash flow generating resource that has improved our ability to compete effectively in the Gulf of Mexico and fund exploration activities and acquisitions. We believe we are well-positioned to optimize the Forest Energy Resources assets through aggressive and timely exploitation.

Our Strategy and Our Competitive Strengths

Our Strategy

The principal elements of our operating strategy include:

Generating and pursuing high-quality prospects. We expect to continue our strategy of growth through the drill bit by continuing to identify and develop high-impact shelf, deep shelf and deepwater projects in the Gulf of Mexico. Our technical team has significant expertise in, and a successful track record of achieving growth by, generating prospects internally and selectively participating in prospects generated by other operators. We believe the Gulf of Mexico is an area that offers substantial growth opportunities, and our acquisition of the Forest Gulf of Mexico operations has more than doubled our existing undeveloped acreage position in the Gulf, providing numerous additional exploration, exploitation and development opportunities.

Maintaining a moderate risk profile. We seek to manage our risk profile by targeting a balanced exposure to development, exploitation and exploration opportunities. For example, we intend to continue to develop and seek to expand our West Texas asset base, which contributes stable cash flows and long-lived reserves to our portfolio as a counterbalance to our high-impact, high-production Gulf of Mexico assets. We also seek to mitigate and diversify our risk in drilling projects by selling partial or entire interests in projects to industry partners or by entering into arrangements with industry partners in which they agree to pay a disproportionate share of drilling costs and compensate us for expenses incurred in prospect generation. We also enter into trades or farm-in transactions whereby we acquire interests in third-party generated prospects, thereby gaining exposure to a greater number of prospects. We expect more opportunities to participate in these prospects in the future as a result of our larger scale and increased cash flow from the Forest Gulf of Mexico operations.

Pursuing opportunistic acquisitions. Until 2005, we grew our reserves primarily through the drill bit. In 2005 we added significant proved reserves primarily through acquisitions in West Texas and subsequently in March 2006, through the acquisition of the Forest Gulf of Mexico operations. As part of our growth strategy, we will seek to continue to acquire producing assets that have the potential to provide acceptable risk-adjusted rates of return and further reserve additions through exploration, exploitation and development opportunities.

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Our Competitive Strengths

We believe our core resources and strengths include:

Our high-quality assets with geographic and geological diversity. Our assets and operations are diversified among the Gulf of Mexico shelf, deep shelf and deepwater, and West Texas. Our asset portfolio provides a balanced exposure to long-lived West Texas reserves, Gulf of Mexico shelf growth opportunities and high-impact deepwater prospects.

Our large inventory of prospects. We believe we have significant potential for growth through the development of our existing asset base. The acquisition of the Forest Gulf of Mexico operations more than doubled our existing undeveloped acreage position in the Gulf of Mexico to approximately 450,000 net acres and increased our total net leasehold acreage offshore to nearly one million acres, providing numerous exploration, exploitation and development opportunities. As of September 30, 2006, we have an inventory of approximately 890 drilling locations in West Texas, which we believe would require approximately six years to drill at our current rate. These include approximately 430 locations pertaining to 98 Bcfe of estimated net proved undeveloped reserves and approximately 460 other locations.

Our successful track record of finding and developing oil and gas reserves. We have demonstrated our expertise in finding and developing additional proved reserves. In the three-year period ended December 31, 2005, we deployed approximately $475 million of capital on acquisitions, exploration and development, while adding approximately 280 Bcfe of proved reserves and producing approximately 100 Bcfe.

Our depth of operating experience. Our team of 41 geoscientists, engineers, geologists and other technical professionals and landmen as of September 30, 2006 average more than 22 years of experience in the exploration and production business (including extensive experience in the Gulf of Mexico), much of it with major oil companies. The addition of experienced Forest personnel to Mariner s team of technical professionals has further enhanced our ability to generate and maintain an inventory of high-quality drillable prospects and to further develop and exploit our assets. Mariner s technical team has also proven to be an effective and efficient operator in West Texas, as evidenced by our successful production and reserve growth there in recent years.

Our technology and production techniques. Our team of geoscientists currently has access to seismic data from multiple, recent vintage 3-D seismic databases covering more than 7,000 blocks in the Gulf of Mexico that we intend to continue to use to develop prospects on acreage being evaluated for leasing and to develop and further refine prospects on our expanded acreage position. We also have extensive experience and a successful track record in the use of subsea tieback technology to connect offshore wells to existing production facilities. This technology facilitates production from offshore properties without the necessity of fabrication and installation of platforms and top-side facilities that typically are more costly and require longer lead times. We believe the use of subsea tiebacks in appropriate projects enables us to bring production online more quickly, makes target prospects more profitable and allows us to exploit reserves that may otherwise be considered non-commercial because of the high cost of infrastructure. In the Gulf of Mexico, in the three years ended December 31, 2005, we were directly involved in 14 projects (five of which we operated) utilizing subsea tieback systems in water depths ranging from 475 feet to more than 6,700 feet. As of September 30, 2006, we had 18 subsea wells in water depths ranging from 450 feet to more than 4,700 feet. These wells were tied back to 13 host production facilities for production processing. An additional nine wells in water depths ranging from 465 feet to more than 6,800 feet were then under development for tieback to five additional host production facilities.

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Properties

We currently own oil and gas properties, producing and non-producing, onshore in Texas and offshore in the Gulf of Mexico, primarily in federal waters. Our largest properties (including the largest properties we acquired in our merger with Forest Energy Resources), based on the present value of estimated future net proved reserves as of December 31, 2005, are shown in the following table.

	Operator	Mariner Working Interest (%)	Approximate Water Depth (Feet)	Gross Producing Wells(1)	Date Production Commenced/ Expected	Estimated Proved Reserves (Bcfe)	PV10 Value ($ In millions)(2)	Stan M m
xas:								
Unit	Mariner	66.5(3)	Onshore	246	*	120.7	$ 367.0	
k/Spraberry Properties	Tamarack	35.0(4)	Onshore	187	*	67.8	103.2	
Mexico Deepwater:								
pi Canyon 296/252	Dominion	22.5	5,200	0(5)	First Quarter 2006	22.5	161.4	
Valley 426 (Bass Lite)	Mariner	38.75(6)	6,800	0	2008	32.3	137.9	
noll 917/961/962 sh)	Mariner(7)	15.0	4,700	2	Fourth Quarter 2005	12.9	101.7	
pi Canyon 718)	Mariner	51.0	2,830	0	1999	9.0	69.3	
nyon 646 (Daniel	W&T Offshore	40.0	4,300	0	2008	16.4	61.8	
nyon 516 (Yosemite)	ENI	44.0	3,900	1	2002	7.8	53.9	
ks 420**	Noble	50.0	2,560	1	2002	13.4	75.8	
Mexico Shelf:								
eron 14**	Mariner	50.0	25	2	*	15.2	91.5	
sland 292**	Mariner	45.0	195	8	*	8.2	54.7	
sland 53**	Mariner	50.0(9)	40	4	*	10.4	78.1	
nd 116**	Mariner	98.9(10)	45	2	*	9.7	52.7	
al 26**	Mariner	100.0	10	1	*	7.2	41.5	
arsh Island 18**	Mariner	100.0	75	1	1993	9.5	50.6	
ss 24-NCOC**	Mariner	100.0	10	15	*	23.5	103.8	
n 14**	Mariner	100.0	20	16	*	32.8	177.7	
n 380**	Mariner	55.0-100.0	320	5	*	11.4	59.2	
meron 110/SE/4 111**	BP/Amoco(11)	37.5(11)	40.5	5	*	9.0	51.9	
meron 111/112**	Mariner	55.0-100.0	43.1	1	2004	6.5	49.8	
meron 205**	Mariner	100.0	50	1	*	5.7	41.9	
roperties				93		48.2	225.6	
roperties (Forest pro *				344		143.6	840.8	

935	643.7	$	3,051.8	$	

* Production commenced twenty or more years ago.

** Pro forma properties from Forest Gulf of Mexico operations.

(1) Wells producing or capable of producing as of December 31, 2005.

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(2) Please see Estimated Proved Reserves for a definition of PV10 and a reconciliation of PV10 to the standardized measure of discounted future net cash flows.

(3) Mariner operates the field and owns working interests in individual wells ranging from approximately 33% to 84%.

(4) Mariner owns an approximate average 35% working interest in producing wells. Upon drilling and completing 150 additional wells, Mariner will obtain an approximate 35% working interest in the entire committed acreage. As of September 30, 2006, 83 of such wells had been drilled and completed.

(5) The Rigel Prospect commenced production with one well in the first quarter of 2006.

(6) Since December 31, 2005, Mariner has exercised a preferential right with respect to the property, thereby increasing its working interest to 42.19%.

(7) Mariner served as operator until December 2005, at which time pursuant to certain contractual arrangements, Noble Energy, Inc., a 60% partner in the project, began serving as operator.

(8) 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, 2005, 8.9 Bcfe of our net proved reserves attributable to this project were classified as proved behind pipe reserves. Production from Pluto recommenced in the third quarter of 2006.

(9) Mariner operates the field and owns working interests in individual wells ranging from approximately 50% to 100%.

(10) Mariner operates the field and owns working interests in individual wells ranging from approximately 98.9% to 100%.

(11) In August 2006, Mariner Energy Resources, Inc. exercised a preferential right with respect to the West Cameron 110 and the southeast quarter of West Cameron 111, thereby increasing its working interest in these properties to 100%, exclusive of retained interests in depths below 15,000 feet. In addition, Mariner Energy, Inc. became operator of the interests its subsidiary owns.

West Texas

Aldwell Unit. We operate and own working interests in individual wells ranging from 33% to 84% (with an average working interest of approximately 66.5%), in the 18,500-acre Aldwell Unit. The field is located in the heart of the Spraberry geologic trend southeast of Midland, Texas, and has produced oil and gas since 1949. We began our recent redevelopment of the Aldwell Unit by drilling eight wells in the fourth quarter of 2002, 43 wells in 2003, 54 wells in 2004 and 65 wells in 2005. As of December 31, 2005, there were a total of 249 wells producing or capable of producing in the field, and as of September 30, 2006, an additional 27 wells were capable of production.

We have completed construction of our own oil and gas gathering system and compression facilities in the Aldwell Unit. We began flowing gas production through the new facilities on June 1, 2005. We have also entered into contracts with third parties to provide processing of our natural gas and transportation of our oil produced in the unit. The 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. These arrangements have improved the economics of production from the Aldwell Unit.

Tamarack/Spraberry Properties. Effective in October 2005, we entered into an agreement covering approximately 33,000 acres in West Texas, pursuant to which, upon closing, we acquired an approximate 35% working interest in approximately 200 existing producing wells effective November 1, 2005, and committed to drill and complete an additional 150 wells within a four-year period, while funding $36.5 million of our partner s share of drilling costs for such 150-well drilling program. We will obtain an assignment of an approximate 35% working interest in the entire committed acreage upon completion of the 150-well program. As of September 30, 2006, we have drilled and completed 83 wells under this agreement.

Other Projects and Activity. In December 2004, we acquired an approximate 50% working interest in two Permian Basin fields containing approximately 4,000 acres. We believe the fields contain more than twenty 80-acre infill drilling locations and that either or both may also have 40-acre infill drilling opportunities. We have commenced drilling operations in one of the fields and as of September 30, 2006, have drilled and completed 23 wells, all of which are productive.

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

In September 2005, we acquired a 100% working interest and 75% net revenue interest in three producing wells and approximately 3,300 leasehold acres that are held by production in the Canyon Sawyer Field in Sutton and Schleicher Counties, Texas. The purchase price was $700,000. Since acquiring the property, we have refracted two of the three producing wells acquired, and drilled and completed six new wells as Canyon Sand gas producers. We expect to complete two additional Canyon Sand wells in the fourth quarter of 2006. We have approximately 20 additional potential drilling locations on the property.

In December 2005, we acquired an interest in approximately 5,500 acres with an average 84% working interest and 64% net revenue interest in the Spraberry trend area 5-10 miles southwest of our Aldwell Unit. The purchase price was $5.5 million with an effective date of August 1, 2005 and included 34 producing wells with the potential to drill an additional 68 wells on 40-acre spacing. During the third quarter of 2006, we drilled and completed five new wells, all of which are productive.

During 2005, our aggregate net capital expenditures for West Texas were approximately $86 million, and we added 97.2 Bcfe of proved reserves, while producing 6.6 Bcfe. Average daily net production from our West Texas operations increased from 10.8 MMcfe per day in 2004 to 17.8 MMcfe per day in 2005, representing an increase of 64%. As of December 31, 2005, our West Texas operations included 487 producing wells on 31,199 net acres, compared to 189 producing wells on 14,448 net acres at December 31, 2004.

Gulf of Mexico Deepwater

Mississippi Canyon 296/252 (Rigel). Mariner generated the Rigel prospect and acquired its interest in Mississippi Canyon block 296 at a federal offshore Gulf lease sale in March 1999. Our working interest in Rigel is 22.5%. The project is located approximately 130 miles southeast of New Orleans, Louisiana, in water depth of approximately 5,200 feet. A successful exploration well was drilled on the prospect in 1999. In September 2003, a successful appraisal well was drilled. This project was developed with a single subsea well tied back 12 miles to an existing subsea manifold that is connected to an existing platform. Production commenced in the first quarter of 2006.

Atwater Valley 426 (Bass Lite). The Bass Lite project is located in Atwater Valley blocks 380, 381, 382, 425 and 426, approximately 200 miles southeast of New Orleans in approximately 6,800 feet of water. We have a 42.19% working interest and have been designated operator of this project. Our working interest partners have approved development plans. The process of selecting suppliers of major equipment and services is substantially complete. Drilling operations are expected to begin in the fourth quarter of 2006, with drilling and completion of two wells anticipated by the second quarter of 2007 and initial production expected in 2008.

Viosca Knoll 917/961/962 (Swordfish). Mariner generated the Swordfish prospect and entered into a farm-out agreement with BP in September 2001. We operated Swordfish until commencement of initial production and own a 15% working interest. The project is located in the deepwater Gulf of Mexico 105 miles southeast of New Orleans, Louisiana, in a water depth of approximately 4,700 feet. In November and December of 2001, we drilled two successful exploration wells on blocks 917 and 962. In August 2004, a successful appraisal well found additional reserves on block 961. All wells have been completed and production commenced in the fourth quarter of 2005 on two wells and in October 2006 on the third well.

Mississippi Canyon 718 (Pluto). Mariner initially acquired an interest in this project in 1997, two years after gas was discovered on the project. We operate the property and own a 51% working interest in the project and the 29-mile flowline that connects to a third-party production platform. We developed the field with a single subsea well which is located in the Gulf of Mexico approximately 150 miles southeast of New Orleans, Louisiana, at a water depth of approximately 2,830 feet. The field was shut-in in April 2004 pending the drilling of a new well and completion of the installation of an infield extension to the existing infield flowline and umbilical. Installation of the subsea facilities is now complete. During start-up operations, a paraffin plug was discovered in the flow-line between the Pluto field and the host facility. Remediation efforts are complete and production recommenced in the third quarter of 2006, following completion of the platform operator s repairs to the host facilities necessitated by damage inflicted by Hurricane Katrina.

Green Canyon 646 (Daniel Boone). Mariner generated the Daniel Boone prospect and acquired a 100% working interest in Daniel Boone at a Gulf of Mexico federal offshore lease sale in July 1998. The project is located in approximately 4,300 feet of water approximately 165 miles south of New Orleans, Louisiana. Subsequent to the acquisition, Mariner entered into a farmout agreement retaining a 40% working interest in the project. A successful exploration well was drilled in 2003. The project will be developed as a subsea tieback to existing infrastructure and is expected to commence production in 2008.

Green Canyon 516 (Yosemite). Mariner generated the Yosemite prospect and acquired the prospect at a Gulf of Mexico federal lease sale in 1998. We have a 44% working interest in this project located in approximately 3,900 feet of water, approximately 150 miles southeast of New Orleans, Louisiana. In 2001, we drilled an exploratory well on the prospect, and in February 2002 commenced production via a 16-mile subsea tieback to an existing platform which also handles production from the King Kong field in Green Canyon 472/473, in which we own a 50% interest.

East Breaks 420. Forest leased three blocks located on this property in 1996 and an additional block in 1998. Forest subsequently sold a 50% working interest to Noble. The property is located in approximately 2,560 feet of water approximately 174 miles southwest of Cameron, Louisiana. A successful well was drilled in 2001. The project was completed with a subsea tieback to existing infrastructure. Production commenced in June 2002. The property was acquired by Mariner on March 2, 2006 as part of its merger with Forest Energy Resources. In the second quarter of 2006, additional compression was added to the host platform which resulted in an approximate 50% increase in production.

Other Projects and Activity. In late 2004, we participated in a successful exploratory well in our North Black Widow prospect in Ewing Banks 921, which is located approximately 125 miles south of New Orleans, Louisiana in approximately 1,700 feet of water. We have a 35% working interest in this project. A development plan for the North Black Widow prospect has been approved and it commenced production in October 2006.

In June 2005, we increased our working interest in the LaSalle project (East Breaks 513, 514 and 558) to 100% by acquiring the remaining working interest owned by a third party for $1.5 million. The blocks contain an undeveloped discovery, as well as exploration potential. We have 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 participation 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 feet and 3,300 feet, respectively. Mariner and Kerr McGee committed to drill four wells, three on East Breaks 602 and one on East Breaks 558. The four wells have been drilled and were successful. First production is expected in 2008, with related completion and facility capital being spent in 2006 and 2007. As of December 31, 2005, we had not recorded proved reserves to these projects.

At the King Kong field (Green Canyon blocks 472 and 473), a two-well drilling program to exploit potential new reserve additions has been executed. We drilled one successful development well on block 473 in the first quarter of 2006, and an unsuccessful exploration well on block 472 in the second quarter of 2006. We own a 50% working interest in the King Kong field in Green Canyon 472 and 473. The development well on Green Canyon 473 has been completed and initial production commenced in April 2006.

Gulf of Mexico Shelf

Each of the following Gulf of Mexico shelf properties was acquired by Mariner on March 2, 2006 as part of its merger with Forest Energy Resources.

East Cameron 14. Forest acquired a 50% working interest in this property through Forest s acquisition of Forcenergy Inc in 2000. Since March 2, 2006, Mariner has operated the property and owns a 50% working interest. This property is located in approximately 25 feet of water, approximately 30 miles southeast of Cameron, Louisiana.

Eugene Island 292. This property was installed in 1967, with first production commencing in 1970. Since March 2, 2006, Mariner has operated the property and owns a 45% working interest in this field. The property consists of a hub for the complex including six platforms. The property is located in approximately 195 feet of water, approximately 140 miles southeast of Cameron, Louisiana.

Eugene Island 53. The shallow rights to this property were acquired in 1993 from Sandefer Offshore Operating. Subsequently, the deep rights were acquired from Pennzoil in 1995 and 1997. Since March 2, 2006, Mariner has operated the property and owns between 50% and 100% working interests in various wells in the field. The property is located in approximately 40 feet of water, approximately 111 miles southeast of Cameron, Louisiana.

High Island 116. This property was acquired in 1993 from Arco. In 2000 Forest purchased the remaining working interests in this property and, since March 2, 2006, Mariner has operated the property and owns a 100% working interest as a result of our acquisition of the Forest Gulf of Mexico operations. The property is located in approximately 45 feet of water, approximately 49 miles southwest of Cameron, Louisiana. In October 2006, we announced that we made a material conventional shelf discovery in the High Island 116 #5ST1 well, drilled to a total measured depth of 14,683 feet / 13,150 feet true vertical depth. The well encountered approximately 540 feet of net true vertical depth pay in thirteen sands. We anticipate completion and initial production in the fourth quarter of 2006. We have a 100% working interest and an approximate 72% net revenue interest in the well.

Ship Shoal 26. This property was acquired through Forest s acquisition of Forcenergy Inc in 2000. Since March 2, 2006, Mariner has operated the property and owns a 100% working interest in the property. The property is located in approximately 10 feet of water, approximately 97 miles southwest of New Orleans, Louisiana.

South Marsh Island 18. This property was acquired through Forest s acquisition of Forcenergy Inc in 2000. Forest subsequently sold a 50% working interest in the property to Union Oil of California (Unocal) in 2001. As part of an acquisition of properties from Unocal in 2003, Forest repurchased Unocal s 50% working interest, and, since March 2, 2006, Mariner has operated the property and holds a 100% working interest. The property is located in approximately 75 feet of water, approximately 101 miles southeast of Cameron, Louisiana.

South Pass 24 NCOC. This property was acquired through Forest s acquisition of Forcenergy Inc in 2000. Forest acquired the remaining working interest (approximately 25%) from Pogo in 2004. Since March 2, 2006, Mariner has operated the property and currently holds a 100% working interest. The property is located approximately 82 miles south of New Orleans, Louisiana in approximately 10 feet of water.

Vermillion 14. A 50% working interest in this property was acquired from Unocal in 2003. In 2004, Forest acquired BP s 50% working interest and, since March 2, 2006, Mariner has operated the property and owns a 100% working interest. The property is located in approximately 20 feet of water, approximately 63 miles southeast of New Orleans, Louisiana.

Vermillion 380. This property was acquired through Forest s acquisition of Forcenergy Inc in 2000. Forest subsequently sold a 50% working interest to Unocal in 2001. As part of the Unocal acquisition in 2003, Forest repurchased Unocal s 50% working interest. Since March 2, 2006, Mariner has operated the property and owns working interests in the individual wells ranging from approximately 55% to 100%. The property is located in approximately 320 feet of water, approximately 135 miles southeast of Cameron, Louisiana.

West Cameron 110/SE/4 111. In August 2006, Mariner Energy Resources, Inc. exercised a preferential right with respect to the West Cameron 110 and the southeast quarter of West Cameron 111, thereby increasing its working interest in these properties to 100%, exclusive of retained interests in depths below

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15,000 feet. In addition, Mariner Energy, Inc. became operator of the interests its subsidiary owns. A 37.5% working interest was acquired through Forest s acquisition of Forcenergy Inc in 2000. The property is located in approximately 45 feet of water, approximately 21 miles south of Cameron, Louisiana.

West Cameron 111/112. This property consists of the north half and southwest quarter of Block 111 and all of Block 112, and was acquired through Forest s acquisition of Forcenergy Inc in 2000. Forest initially held a 100% working interest in the property and sold a portion of its working interest in 2003. Effective July 2005, Forest reacquired the working interests sold in the north half and southwest quarter of Block 111 and, as a result, Mariner owns a 100% working interest in the Block 111 portion of the property and a 55% working interest in Block 112. Since March 2, 2006, Mariner has operated the property. The property is located in approximately 40 feet of water, approximately 45 miles southeast of Cameron, Louisiana.

West Cameron 205. This property was acquired through Forest s acquisition of Forcenergy Inc in 2000. Since March 2, 2006, Mariner has operated the property and owns a 100% working interest in the property, which is located in approximately 50 feet of water, approximately 36 miles south of Cameron, Louisiana.

Other Projects and Activity. In connection with the March 2005 Central Gulf of Mexico federal lease sale, Mariner was awarded West Cameron 386 located in water depth of approximately 85 feet. In connection with the August 2005 Western Gulf of Mexico lease sale, we were awarded one shelf block (High Island A2) and four deepwater blocks (East Breaks 344, East Breaks 709, East Breaks 844 and East Breaks 843).

In May 2005, Mariner drilled the Capricorn discovery well, which encountered over 100 net feet of pay in four zones. The Capricorn project is located on High Island A341 approximately 115 miles south southwest of Cameron, Louisiana, in approximately 240 feet of water. During 2006, the platform and facilities were installed, and a successful appraisal well was drilled. Production from two wells commenced in the third quarter of 2006.

In late 2002, Mariner drilled a successful exploration well on our Mississippi Canyon 66 (Ochre) prospect and commenced production in the first quarter of 2004 via subsea tieback of approximately 7 miles to the Taylor Mississippi Canyon 20 platform. In September 2004, Hurricane Ivan destroyed the Taylor platform. We have entered into a production handling agreement with the operator of the nearby Amberjack (MC109) host facility, and production recommenced in the third quarter of 2006, following completion of the operator s repairs to the host facility necessitated by damage inflicted by Hurricane Katrina.

In connection with the March 2006 Central Gulf of Mexico lease sale, Mariner was the high bidder on ten blocks including two deepwater blocks, at a potential aggregate cost of $18 million to Mariner. We have been awarded nine blocks, including the block on which we made our highest bid and the two deepwater blocks (Mississippi Canyon 152 and 239). Our net cost exposure for the nine blocks is approximately $16.5 million. No lease was awarded on a tenth block on which we also were the high bidder.

At the August 2006 Western Gulf of Mexico lease sale, Mariner was the apparent high bidder on six blocks, including High Island Blocks 233, A21, A126, A154, A155 and A480, located in water depths ranging from 39 feet to 151 feet. Mariner has been awarded all six blocks. Our cost for the approximately 25,000 net acres covered by the six blocks is approximately $4.4 million.

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Estimated Proved Reserves

The following table sets forth certain information with respect to our estimated proved reserves by geographic area as of December 31, 2005. Reserve volumes and values were determined under the method prescribed by the SEC which requires the application of period-end prices and costs held constant throughout the projected reserve life. The reserve information as of December 31, 2005 for Mariner is based on estimates made in a reserve report prepared by Ryder Scott.

	Estimated Proved Reserve Quantities			PV10 Value(3)			
Geographic Area	Oil (MMbbls)	Natural Gas (Bcf)	Total (Bcfe)	Developed	Undeveloped	Total	Standardized Measure
West Texas	16.7	105.5	205.5	$ 333.7	$ 173.4	$ 507.1	
Gulf of Mexico Deepwater(1)	4.7	83.2	111.1	383.3	257.4	640.7	
Gulf of Mexico Shelf(2)	0.3	19.0	21.0	132.6	1.4	134.0	
Total	21.7	207.7	337.6	$ 849.6	$ 432.2	$ 1,281.8	$ 906.6
Proved Developed Reserves	9.6	110.0	167.4				

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

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

(3) Please see below for a definition of PV10 and a reconciliation of PV10 to the standardized measure of discounted future net cash flows.

The following table sets forth certain information with respect to our pro forma estimated proved reserves by geographic area as of December 31, 2005. This information is presented on a pro forma basis, giving effect to our merger with Forest Energy Resources as though it had been consummated on December 31, 2005. We consummated the merger on March 2, 2006. The reserve information as of December 31, 2005 for the Forest Gulf of Mexico operations is based on estimates made by internal staff engineers at Forest, which estimates were audited by Ryder Scott. Accordingly, the pro forma reserve information presented below includes both reserves that were estimated by Ryder Scott and reserves that were estimated by internal staff engineers at Forest and audited by Ryder Scott.

	Pro Forma Estimated Proved Reserve Quantities			Pro Forma PV10 Value(3)			Pro Forma
Geographic Area	Oil (MMbbls)	Natural Gas (Bcf)	Total (Bcfe)	Developed	Undeveloped	Total	Standardized Measure

					($ millions)		**($ millions)**
West Texas	16.7	105.5	205.5	$ 333.7	$ 173.4	$ 507.1	
Gulf of Mexico Deepwater(1)	4.8	95.7	124.5	406.3	310.3	716.6	
Gulf of Mexico Shelf(2)	12.7	237.6	313.7	1,283.4	544.7	1,828.1	
Total	34.2	438.8	643.7	$ 2,023.4	$ 1,028.4	$ 3,051.8	$ 2,201.7
Proved Developed Reserves	18.4	252.1	362.3				

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

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

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(3) Please see below for a definition of PV10 and a reconciliation of PV10 to the standardized measure of discounted future net cash flows.

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond the control of Mariner. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and the interpretation thereof. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing, and production subsequent to the date of an estimate, as well as economic factors such as change in product prices, may require revision of such estimates. Accordingly, oil and gas quantities ultimately recovered may vary from reserve estimates.

PV10 is our estimated present value of future net revenues from proved reserves before income taxes. PV10 may be considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe PV10 to be an important measure for evaluating the relative significance of our natural gas and oil properties and that PV10 is widely used by professional analysts and investors in evaluating oil and gas companies. Because many factors that are unique to each individual company affect the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV10 on the same basis. Management also uses PV10 in evaluating acquisition candidates. PV10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes. The table below provides a reconciliation of PV10 (and, with respect to 2005, pro forma PV10) to the standardized measure of discounted future net cash flows.

	Pro Forma at December 31, 2005	At December 31, 2005	2004	2003
		(In millions)		
PV10	$ 3,051.8	$ 1,281.8	$ 668.0	$ 533.5
Future income taxes, discounted at 10%	850.1	375.2	173.6	115.3
Standardized measure of discounted future net cash flows	$ 2,201.7	$ 906.6	$ 494.4	$ 418.2

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Therefore, without reserve additions in excess of production through successful exploration and development activities or acquisitions, Mariner s reserves and production will decline. See Risk Factors and Note 11 to the Mariner financial statements included elsewhere in this prospectus for a discussion of the risks inherent in oil and natural gas estimates and for certain additional information concerning the proved reserves.

The weighted average prices of oil and natural gas at December 31, 2005 used in the proved reserve and future net revenues estimates above were calculated using NYMEX prices at December 31, 2005, of $61.04 per bbl of oil and $10.05 per MMBtu of gas, adjusted for our price differentials but excluding the effects of hedging.

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Production

The following table presents certain information with respect to net oil and natural gas production attributable to our properties, average sales price received and expenses per unit of production during the periods indicated. The information for the nine months ended September 30, 2006 and year ended December 31, 2005 also is presented on a pro forma basis, giving effect to our merger with Forest Energy Resources as though it had been consummated on January 1, 2005. We consummated the merger on March 2, 2006.

	Pro Forma					
	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	2004	2003
Production:						
Natural gas (Bcf)	45.6	67.5	39.3	18.4	23.8	23.8
Oil (Mbbls)	2.8	4.6	2.5	1.8	2.3	1.6
Total natural gas equivalent (Bcfe)	62.4	94.9	54.5	29.1	37.6	33.4
Average daily natural gas equivalent (MMcfe)	228.5	260.0	200.0	79.7	103.0	91.5
Average realized sales price per unit (excluding the effects of hedging):						
Natural gas ($/Mcf)	$ 7.25	$ 8.04	$ 7.05	$ 8.33	$ 6.12	$ 5.43
Oil ($/bbl)	61.23	48.86	62.13	51.66	38.52	26.85
Total natural gas equivalent ($/Mcfe)	8.05	8.07	7.94	8.43	6.23	5.15
Average realized sales price per unit (including the effects of hedging):						
Natural gas ($/Mcf)	$ 7.42	$ 6.40	$ 7.25	$ 6.66	$ 5.80	$ 4.40
Oil ($/bbl)	58.95	34.18	59.58	41.23	33.17	23.74
Total natural gas equivalent ($/Mcfe)	8.07	6.20	8.00	6.74	5.70	4.27
Expenses ($/Mcfe):						
Lease operating expenses	$ 1.26	$ 1.04	$ 1.15	$ 0.86	$ 0.61	$ 0.69
Severance and ad valorem taxes	0.10	0.13	0.10	0.17	0.07	0.05
Transportation	0.07	0.06	0.07	0.08	0.08	0.19
General and administrative, net(1)			0.46	1.27	0.23	0.24
Depreciation, depletion and amortization (excluding impairments)(2)	3.51	3.47	3.53	2.04	1.73	1.45

(1) Net of overhead reimbursements received from other working interest owners and amounts capitalized under the full cost accounting method. Includes non-cash stock compensation expense of $9.0 million for the nine months ended September 30, 2006 and $25.7 million in 2005. General and administrative expenses, net of capitalized amounts, are not included in pro forma 2005 because accounts of such costs were not historically maintained for the Forest Gulf of Mexico operations as a separate business unit. We believe the overhead costs associated with

the Forest Gulf of Mexico operations in 2006 will approximate $6.4 million, net of capitalized amounts.

(2) Pro forma depreciation, depletion and amortization gives effect to the acquisition of the Forest Gulf of Mexico operations and a preliminary estimate of their step-up in value basis the unit of production method under the full cost method of accounting.

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Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned a working interest at December 31, 2005 and December 31, 2004, and on a pro forma basis at December 31, 2005.

	Pro Forma at December 31, 2005		Total Productive Wells at			
			December 31, 2005		December 31, 2004	
	Gross	Net	Gross	Net	Gross	Net
Oil	669	335.0	492	271.3	197	127.9
Gas	266	117.3	37	10.7	34	9.5
Total	935	452.3	529	282.0	231	137.4

Acreage

The following table sets forth certain information with respect to actual developed and undeveloped acreage as of September 30, 2006, and pro forma and actual developed and undeveloped acreage as of December 31, 2005. The pro forma information gives effect to our merger with Forest Energy Resources as though it had been consummated on December 31, 2005. We consummated the merger on March 2, 2006.

September 30, 2006				Pro Forma at December 31, 2005				At December 31		
Developed Acres(1)		Undeveloped Acres(2)		Developed Acres(1)		Undeveloped Acres(2)		Developed Acres(1)		
ross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	G
59,974	31,186			59,974	31,199			59,974	31,199	
91,980	36,026	328,320	225,466	90,720	36,035	332,528	205,285	79,200	30,275	2
74,758	372,658	339,053	217,805	1,007,882	399,184	399,792	251,915	136,062	40,435	1
1,311	344	854	242	3,392	744	856	243	3,392	744	
28,023	440,214	668,227	443,513	1,161,968	467,162	733,176	457,443	278,628	102,653	3

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

(3) Includes 31,933 gross and 11,883 net acres committed under the Tamarack/Spraberry drill-to-earn program. Under this program, upon drilling and completing 150 additional wells, Mariner will obtain an approximate 35%

working interest in all committed acreage. As of September 30, 2006, 83 of such wells had been drilled and completed.

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

(5) Shelf refers to water depths less than 1,300 feet.

The following table sets forth Mariner s offshore undeveloped acreage as of December 31, 2005 that is subject to expiration during the three years ended December 31, 2008. The amount of onshore undeveloped acreage subject to expiration is not material.

	Undeveloped Acreage Subject to Expiration in the Year Ended December 31,					
	2006		**2007**		**2008**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil	46,080	12,988	28,800	9,360	51,840	30,240
Gas	10,760	6,260	46,000	31,183	25,760	16,510
Total	56,840	19,248	74,800	40,543	77,600	46,750

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Drilling Activity

Certain information with regard to our drilling activity during the nine months ended September 30, 2006 and the years ended December 31, 2005, 2004 and 2003 is set forth below.

	Nine Months Ended September 30		Year Ended December 31,					
	2006		2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:								
Producing	14	5.83	3	1.13	7	3.34	6	2.03
Dry	5	2.50	7	2.44	7	2.65	6	2.35
Total	19	8.33	10	3.57	14	5.99	12	4.38
Development wells:								
Producing	127	61.15	93	54.20	56	34.84	45	30.07
Dry					1	0.68		
Total	127	61.15	93	54.20	57	35.52	45	30.07
Total wells:								
Producing	141	66.98	96	55.33	63	38.18	51	32.10
Dry	5	2.50	7	2.44	8	3.33	6	2.35
Total	146	69.48	103	57.77	71	41.51	57	34.45

As of September 30, 2006, we were in the process of drilling three gross (1.2 net) wells in the Gulf of Mexico and five gross (approximately 2.0 net) wells in West Texas.

Property Dispositions

When appropriate, we consider the sale of discoveries that are not yet producing or have recently begun producing when we believe we can obtain acceptable returns on our investment without holding the investment through depletion. Such sales enable us to maintain and redeploy the proceeds to activities that we believe have a higher potential financial return. No property dispositions of producing properties were made during the three years ended December 31, 2005. We sold working interests totaling 50% in each of our non-producing deepwater Falcon and Harrier projects in two separate sales for $48.8 million in 2002 and $121.6 million in 2003.

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Marketing and Customers

We market substantially all of the oil and natural gas production from the properties we operate as well as the properties operated by others where our interest is significant. The majority of our natural gas, oil and condensate production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market-based prices. The following table lists customers accounting for more than 10% of our total revenues for the year indicated.

	Percentage of Total Revenues for Year Ended December 31,		
Customer	**2005**	**2004**	**2003**
Sempra		*	34%
Bridgeline Gas Distributing Company(1)	15%	27%	19%
Trammo Petroleum Inc.	*	9%	14%
Duke Energy	*	*	6%
Genesis Crude Oil LP		*	4%
Chevron Texaco and affiliates(1)	24%	18%	
BP Energy	*	12%	
Plains Marketing LP	10%		

* Less than 1%

(1) Bridgeline Gas Distributing Company is an affiliate of ChevronTexaco.

Title to Properties

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

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

Competition

We believe that our leasehold acreage, exploration, drilling and production capabilities, large 3-D seismic database and technical and operational experience generally enable us to compete effectively. However, our primary competitors include major integrated oil and natural gas companies and major independent oil and natural gas companies. Many of our larger competitors possess and employ financial and personnel resources substantially greater than those available to us. Such companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future is dependent upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry. Larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden

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of changes in laws and regulations more easily than we can, which would adversely affect our competitive position.

Royalty Relief

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

Water Depth	Royalty Relief
200-400 meters	no royalty payable on the first 105 Bcfe produced
400-800 meters	no royalty payable on the first 315 Bcfe produced
800 meters or deeper	no royalty payable on the first 525 Bcfe produced

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

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

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

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

Many of our leases from the MMS contain language suspending royalty relief if commodity prices exceed predetermined threshold levels for a given calendar year. As a result, royalty relief for a lease in a particular calendar year may be contingent upon average commodity prices staying below the threshold price specified for that year. In 2000, 2001, 2003, 2004 and 2005, natural gas prices exceeded the applicable price thresholds for a number of our projects, and we have been required to pay royalties for natural gas produced in those years. However, we have contested the authority of the MMS to include price thresholds in two of our post-Act leases, Black Widow and Garden Banks 367. We believe that post-Act leases are entitled to automatic royalty relief under the RRA regardless of commodity prices, and have pursued administrative and judicial remedies in this dispute with the MMS. For more information concerning the contested royalty payments and the MMS s demands, see Legal Proceedings below.

Regulation

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

Transportation and Sale of Natural Gas

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

In August, 2005, Congress enacted the Energy Policy Act of 2005, or EP Act 2005. Among other matters, EP Act 2005 amends the Natural Gas Act, or NGA, to make it unlawful for any entity , including otherwise non-jurisdictional producers such as Mariner, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. On January 19, 2006, the FERC issued regulations implementing this provision. The regulations make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EP Act 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of the FERC s enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

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

Regulation of Production

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

Most of our offshore operations are conducted on federal leases that are administered by the MMS. Such leases require compliance with detailed MMS regulations and orders pursuant to the Outer Continental Shelf Lands Act that are subject to interpretation and change by the MMS. Among other things, we are required to obtain prior MMS approval for our exploration plans and development and production plans at each lease. MMS regulations also impose construction requirements for production facilities located on federal offshore leases, as well as detailed technical requirements for plugging and abandonment of wells, and removal of platforms and other production facilities on such leases. The MMS requires lessees to post surety bonds, or provide other acceptable financial assurances, to ensure all obligations are satisfied on federal offshore leases. The cost of these surety bonds or other financial assurances can be substantial, and there is no assurance that bonds or other financial assurances can be obtained in all cases. We are currently in compliance with all MMS financial assurance requirements. Under certain circumstances, the MMS is authorized to suspend or terminate operations on federal offshore leases. Any suspension or termination of operations on our offshore leases could have an adverse effect on our financial condition and results of operations.

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

Environmental Regulations

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

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

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

Spills and Releases. The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and analogous state laws, impose joint and several liability, without regard to fault or the legality of the original act, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner and operator of the site where the release occurred, past owners and operators of the site, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Responsible parties under CERCLA may be liable for the costs of

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cleaning up hazardous substances that have been released into the environment and for damages to natural resources. Additionally, it is not uncommon for neighboring landowners and other third parties to file tort claims for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. In the course of our ordinary operations, we may generate waste that may fall within CERCLA s definition of a hazardous substance.

We currently own, lease or operate, and have in the past owned, leased or operated, numerous properties that for many years have been used for the exploration and production of oil and gas. Many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or release of hydrocarbons or other wastes were not under our control. It is possible that hydrocarbons or other wastes may have been disposed of or released on or under such properties, or on or under other locations where such wastes may have been taken for disposal. These properties and wastes disposed thereon may be subject to CERCLA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination, or to pay the costs of such remedial measures. Although we believe we have utilized operating and disposal practices that are standard in the industry, during the course of operations hydrocarbons and other wastes may have been released on some of the properties we own, lease or operate. We are not presently aware of any pending clean-up obligations that could have a material impact on our operations or financial condition.

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

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

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

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In furtherance of the Clean Water Act, the EPA promulgated the Spill Prevention, Control, and Countermeasure, or SPCC, regulations, which require facilities that possess certain threshold quantities of oil that could impact navigable waters or adjoining shorelines to prepare SPCC plans and meet specified construction and operating standards. The SPCC regulations were revised in 2002 and required the amendment of SPCC plans before February 18, 2006, if necessary, and requires compliance with the implementation of such amended plans by August 18, 2006 (on February 17, 2006, this compliance deadline was extended until October 31, 2007). We may be required to prepare SPCC plans for some of our facilities where a spill or release of oil could reach or impact jurisdictional waters of the U.S.

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

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and analogous state and local laws and regulations govern the management of wastes, including the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a generator or transporter of hazardous waste or an owner or operator of a hazardous waste treatment, stor or disposal facility. RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil and natural gas. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA s requirements because our operations generate minimal quantities of hazardous wastes. However, these wastes may be regulated by EPA or state agencies as solid waste. In addition, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils, may be regulated under RCRA as hazardous waste. We do not believe the current costs of managing our wastes, as they are presently classified, to be significant. However, any repeal or modification of the oil and natural gas exploration and production exemption, or modifications of similar exemptions in analogous state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Employees

As of September 30, 2006, we had 214 full-time employees. Our employees are not represented by any labor unions. We consider relations with our employees to be satisfactory. We have never experienced a work stoppage or strike.

Legal Proceedings

Each of Mariner and its subsidiary, Mariner Energy Resources, Inc., owns numerous properties in the Gulf of Mexico. Certain of these properties were leased from the MMS subject to the RRA. The RRA relieved the obligation to pay royalties on certain leases until a designated volume is produced. Two of these leases held by Mariner and one held by its subsidiary contained language that limited royalty relief if commodity prices exceeded predetermined levels. Since 2000, commodity prices have exceeded the predetermined levels, except in 2002. Mariner and its subsidiary believe the MMS did not have the authority to set pricing limits in these leases and have withheld payment of royalties on the leases while disputing the MMS authority in two pending proceedings. Mariner has recorded a liability for 100% of the exposure on its two leases, which at September 30, 2006 was $19.9 million. Various legal proceedings are pending concerning this potential liability and further proceedings may be initiated with respect to years not covered by the pending proceedings. In April 2005, the MMS denied Mariner s administrative appeal of the MMS April 2001 order asserting royalties were due because price limits had been exceeded. In October 2005, Mariner filed suit in the

U.S. District Court for the Southern District of Texas seeking judicial review of the dismissal. Upon motion of the MMS, Mariner s lawsuit was dismissed on procedural grounds. In August 2006, Mariner filed an appeal of such dismissal. Mariner had also filed an administrative appeal of a December 2005 order of the MMS demanding royalties for calendar year 2004 under the same leases at issue in the April 2001 MMS order. However, the MMS withdrew such order, rendering the appeal moot. Thereafter, in May 2006, the MMS issued an order asserting price limits were exceeded in calendar years 2001, 2003 and 2004 and, accordingly, that royalties were due under such leases on oil and gas produced in those years. Mariner has filed and is pursuing an administrative appeal of that order.

The potential liability of Mariner Energy Resources, Inc. under its lease subject to the RRA containing such commodity price threshold language is approximately $2.2 million as of September 30, 2006. This potential liability relates to production from the lease commencing July 1, 2005, the effective date of Mariner s acquisition of Mariner Energy Resources, Inc. A reserve for this possible liability will be made when deemed appropriate. The MMS has not yet made demand for non-payment of royalties alleged to be due for calendar years subsequent to 2004 on the basis of price thresholds being exceeded.

In the ordinary course of business, we are a claimant and/or a defendant in various legal proceedings, including proceedings as to which we have insurance coverage and those that may involve the filing of liens against us or our assets. We do not consider our exposure in these proceedings, individually or in the aggregate, to be material.

Insurance Matters

In September 2004, we incurred damage from Hurricane Ivan that affected our Mississippi Canyon 66 (Ochre) and Mississippi Canyon 357 fields. Production from Ochre was shut-in until September 2006, when repairs to a host platform were completed and production recommenced at about the same net rate of approximately 6.5 MMcfe per day as it was prior to Hurricane Ivan. Production from Mississippi Canyon 357 was shut-in until March 2005, when necessary repairs were completed and production recommenced. It subsequently has been shut-in since Hurricane Katrina, with production expected to recommence in the first quarter of 2007 after completion of host platform repairs. We expect to be reimbursed for costs expended in excess of our annual deductible of $1.25 million plus a single occurrence deductible of $.375 million in effect for the insurance period ended September 30, 2004. Through September 30, 2006, we recovered approximately $2.4 million in insurance proceeds.

In 2005, our operations were adversely affected by one of the most active and severe hurricane seasons in recorded history, resulting in shut-in production and startup delays. We estimate that as of September 30, 2006, approximately 12 MMcfe per day of production remained shut-in and approximately 33 MMcfe per day of production had recommenced since June 30, 2006. The four deepwater projects that experienced startup delays have recommenced production. As a result of ongoing repairs to pipelines, facilities, terminals and host facilities, we expect most of the remaining shut-in production to recommence by the end of 2006 and the balance in 2007, except that an immaterial amount of production is not expected to recommence. Actual commencement or recommencement of deferred or shut-in production will vary based on circumstances beyond our control, including the timing of repairs to both onshore and offshore platforms, pipelines and facilities, the actions of operators on our fields, availability of service equipment, and weather.

As of September 30, 2006, we had paid $72.8 million toward the repair of physical damage caused by Hurricanes Katrina and Rita and estimate that total hurricane-related repairs during 2006 and 2007 will be approximately $85.0 million. While this is our current estimate of the cost of all hurricane-related repairs, the ultimate cost cannot be ascertained until we are able to complete all of the repairs. Approximately $82.4 million of this amount relates to the Forest Gulf of Mexico operations we acquired and which were more directly affected by the path of the hurricanes than were Mariner s historical assets. As a result of our acquisition of the Forest Gulf of Mexico operations, we are responsible for the 2005 season hurricane-related repairs to the Forest assets and entitled to the proceeds from Forest s insurance policies applicable to such repairs. Mariner s historical Gulf assets sustained only $2.6 million in physical damage from the hurricanes.

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Forest s insurance coverage for the hurricane damage is subject to a $10 million deductible. Forest s primary carrier has advised Mariner that, inasmuch as aggregate claims resulting from the hurricanes are expected to exceed the carrier s $500 million per occurrence loss limit, Mariner s primary claim pertaining to the Forest Gulf of Mexico operations is expected to be reduced pro rata with all other competing claims from the storms. To the extent insurance recovery under the primary policy relating to the Forest assets is reduced, Mariner believes the shortfall would be collectible under Forest s excess insurance coverage. The insurance coverage pertaining to Mariner s historical properties is subject to an aggregate $3.75 million deductible, which we do not expect to exceed given the limited physical damage sustained by Mariner s historical properties.

Taking into account Forest s insurance coverage in effect at the time of Hurricanes Katrina and Rita, we currently estimate our unreimbursed losses from hurricane-related repairs should not exceed $15 million. Given the magnitude and complexity of the insurance claims currently being processed by the insurance industry with respect to these two significant storms, however, the timing of our ultimate insurance recovery presently cannot be ascertained. Although we expect to begin receiving insurance proceeds early in 2007, we believe that a complete insurance settlement of all hurricane-related claims may take several additional quarters. As a result, we expect to maintain a possibly significant insurance receivable for the indefinite future while we actively pursue settlement of our claims to minimize the impact to our working capital and liquidity.

Effective March 2, 2006, Mariner has been accepted as a member of OIL Insurance, Ltd., an industry insurance cooperative, through which all of Mariner s assets are insured. The coverage contains a $5 million annual per-occurrence deductible for the combined assets and a $250 million per-occurrence loss limit. However, if a single event causes losses to OIL insured assets in excess of $500 million, amounts covered for such losses will be reduced on a pro rata basis among OIL members. We maintained our commercially underwritten insurance coverage for the premerger Mariner assets, which coverage expired on September 30, 2006. This coverage contained a $3 million annual deductible and a $500,000 occurrence deductible, $150 million of aggregate loss limits, and limited business interruption coverage. While the coverage was in effect, it was primary to the OIL coverage for the pre-merger Mariner assets. We have acquired additional windstorm/physical damage insurance covering all of Mariner s assets to supplement the existing OIL coverage. The coverage provides up to $31 million of annual loss coverage (with no additional deductible) if recoveries from OIL for insured losses are reduced by the OIL overall loss limit (i.e., if losses to OIL insured assets from a single event exceed $500 million). We also have acquired additional limited business interruption insurance on most of our deepwater producing fields which becomes effective 60 days after a field is shut-in due to a covered event. The coverage varies by field and is limited to a maximum recovery resulting from windstorm damage of approximately $43 million (assuming all covered fields are shut-in for the full insurance term of 365 days).

Enron Related Matters

In 1996, JEDI, an indirect wholly owned subsidiary of Enron Corp., acquired approximately 96% of Mariner Energy LLC, which at the time of acquisition indirectly owned 100% of Mariner Energy, Inc. After JEDI acquired us, we continued our prior business as an independent oil and natural gas exploration, development and production company. In 2001, Enron Corp. and certain of its subsidiaries (excluding JEDI) became debtors in Chapter 11 bankruptcy proceedings. Mariner Energy, Inc. was not one of the debtors in those proceedings. While the bankruptcy proceedings were ongoing, we continued to operate our business as an indirect subsidiary of JEDI. We remained an indirect subsidiary of JEDI until March of 2004 when our former indirect parent company, Mariner Energy LLC, merged with an affiliate of the private equity funds Carlyle/Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC. In the merger, all the shares of common stock in Mariner Energy LLC were converted into the right to receive cash and certain other consideration. As a result, since March 2004, JEDI has not owned any direct or indirect interest in Mariner, and we have not had any affiliation with JEDI or Enron Corp. Also in connection with the merger, warrants to purchase common stock of Mariner Energy LLC that were held by another Enron Corp. affiliate were exercised and the holders received their pro rata portion of the merger consideration, and a term loan owed by Mariner Energy LLC to the same Enron Corp. affiliate was repaid in full.

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Prior to the merger, we filed two proofs of claim in the Enron Corp. bankruptcy proceedings. These claims, aggregating $10.7 million, were for unpaid amounts owed to us by Enron Corp. subsidiaries under the terms of various physical commodity contracts and hedging contracts entered into prior to the Enron Corp. bankruptcy filing. We assigned these claims to JEDI as part of the merger consideration payable to JEDI under the terms of the merger agreement. Thus, as of this date, we have no claims pending in the Enron Corp. bankruptcy proceedings.

As part of the merger consideration payable to JEDI, we also issued a term promissory note to JEDI in the amount of $10 million. The note bore interest, paid in kind, at a rate of 10% per annum until March 2, 2005, and 12% per annum thereafter unless paid in cash in which event the rate remained at 10% per annum. The JEDI promissory note was secured by a lien on three of our properties located in the Outer Continental Shelf of the Gulf of Mexico. We used a portion of proceeds from the common stock we sold in our March 2005 private equity placement to repay $6 million of the JEDI Note. The note matured on March 2, 2006 and was repaid in full.

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

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MANAGEMENT

Directors and Executive Officers

The Board of Directors of Mariner is composed of seven directors.

The following table sets forth the names, ages (as of November 3, 2006) and titles of the individuals who are the directors and executive officers of Mariner. All directors are elected for terms in accordance with their class, as described in Board of Directors below. All executive officers hold office until their successors are elected and qualified. There are no family relationships among any of our directors or executive officers.

Name	Age	Position with Company
Scott D. Josey	49	Chairman of the Board, Chief Executive Officer and President
Dalton F. Polasek	54	Chief Operating Officer
John H. Karnes	45	Senior Vice President, Chief Financial Officer and Treasurer
Jesus G. Melendrez	47	Senior Vice President Corporate Development
Mike C. van den Bold	43	Senior Vice President and Chief Exploration Officer
Teresa G. Bushman	57	Senior Vice President, General Counsel and Secretary
Judd A. Hansen	50	Senior Vice President Shelf and Onshore
Cory L. Loegering	51	Senior Vice President Deepwater
Richard A. Molohon	52	Vice President Reservoir Engineering
Bernard Aronson	60	Director
Alan R. Crain, Jr.	55	Director
Jonathan Ginns	42	Director
John F. Greene	66	Director
H. Clayton Peterson	61	Director
John L. Schwager	58	Director

Scott D. Josey Mr. Josey has served as Chairman of the Board since August 2001. Mr. Josey was appointed Chief Executive Officer in October 2002 and President in February 2005. From 2000 to 2002, Mr. Josey served as Vice President of Enron North America Corp. and co-managed its Energy Capital Resources group. From 1995 to 2000, Mr. Josey provided investment banking services to the oil and gas industry and portfolio management services. From 1993 to 1995, Mr. Josey was a Director with Enron Capital & Trade Resources Corp. in its energy investment group. From 1982 to 1993, Mr. Josey worked in all phases of drilling, production, pipeline, corporate planning and commercial activities at Texas Oil and Gas Corp. Mr. Josey is a member of the Society of Petroleum Engineers and the Independent Producers Association of America.

Dalton F. Polasek Mr. Polasek was appointed Chief Operating Officer in February 2005. From April 2004 to February 2005, Mr. Polasek served as Executive Vice President Operations and Exploration. From August 2003 to April 2004, he served as Senior Vice President Shelf and Onshore. From August 2002 to August 2003, he was Senior Vice President, and from October 2001 to January 2003, he was a consultant to Mariner. Prior to joining Mariner, Mr. Polasek was self employed from February 2001 to October 2001 and served as: Vice President of Gulf Coast Engineering for Basin Exploration, Inc. from 1996 until February 2001; Vice President of Engineering for SMR Energy Income Funds from 1994 to 1996; director of Gulf Coast Acquisitions and Engineering for General Atlantic Resources, Inc. from 1991 to 1994; and manager of planning and business development for Mark Producing Company from 1983 to 1991. He began his career in 1975 as a reservoir engineer for Amoco Production Company. Mr. Polasek is a Registered Professional Engineer in Texas and a member of the Independent Producers Association of America, the American Association of Drilling Engineers and the American Petroleum Institute.

John H. Karnes Mr. Karnes was appointed Senior Vice President, Chief Financial Officer and Treasurer in October 2006. He served as Senior Vice President and Chief Financial Officer of The Houston Exploration Company from November 2002 through December 2005. He then served as Executive Vice

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President and Chief Financial Officer of Maxxam Inc. from April 2006 to July 2006, and Senior Vice President and Chief Financial Officer of CDX Gas, LLC from July 2006 to August 2006. Prior to joining Houston Exploration, Mr. Karnes was Vice President and General Counsel of Encore Acquisition Company, a NYSE-listed oil and gas producer, from January 2002 to November 2002, and Executive Vice President and Chief Financial Officer of CyberCash, Inc., a NASDAQ-listed internet payment software and services provider, during 2000 and 2001. He also served as Chief Operating Officer of CyberCash during the disposition of its operating divisions through a pre-packaged Chapter 11 bankruptcy proceeding in 2001. Earlier in his career, he served in senior management roles at several publicly-traded companies, including Snyder Oil Corporation and Apache Corporation, practiced law with the national law firm of Kirkland & Ellis, and was employed in various roles in the securities industry. Mr. Karnes has a J.D. from Southern Methodist University School of Law and a B.B.A. in Accounting from The University of Texas at Austin.

Jesus G. Melendrez Mr. Melendrez was promoted to Senior Vice President Corporate Development in April 2006 and served as Vice President Corporate Development from July 2003 to April 2006. Mr. Melendrez also served as a director of Mariner from April 2000 to July 2003. From February 2000 until July 2003, Mr. Melendrez was a Vice President of Enron North America Corp. in the Energy Capital Resources group where he managed the group s portfolio of oil and gas investments. He was a Senior Vice President of Trading and Structured Finance with TXU Energy Services from 1997 to 2000, and from 1992 to 1997, Mr. Melendrez was employed by Enron in various commercial positions in the areas of domestic oil and gas financing and international project development. From 1980 to 1992, Mr. Melendrez was employed by Exxon in various reservoir engineering and planning positions.

Mike C. van den Bold Mr. van den Bold was promoted to Senior Vice President and Chief Exploration Officer in April 2006 and served as Vice President and Chief Exploration Officer from April 2004 to April 2006. From October 2001 to April 2004, he served as Vice President Exploration. Mr. van den Bold joined Mariner in July 2000 as Senior Development Geologist. From 1996 to 2000, Mr. van den Bold worked for British-Borneo Oil & Gas plc. He began his career at British Petroleum. Mr. van den Bold has over 17 years of industry experience. He is a Certified Petroleum Geologist, Texas Board Certified Geologist and member of the American Association of Petroleum Geologists.

Teresa G. Bushman Ms. Bushman was promoted to Senior Vice President, General Counsel and Secretary in April 2006 and served as Vice President, General Counsel and Secretary from June 2003 to April 2006. From 1996 until joining Mariner in 2003, Ms. Bushman was employed by Enron North America Corp., most recently as Assistant General Counsel representing the Energy Capital Resources group, which provided debt and equity financing to the oil and gas industry. Prior to joining Enron, Ms. Bushman was a partner with Jackson Walker, LLP, in Houston.

Judd A. Hansen Mr. Hansen was promoted to Senior Vice President Shelf and Onshore in April 2006 and served as Vice President Shelf and Onshore from February 2002 to April 2006. From October 2001 to February 2002, Mr. Hansen was self-employed as a consultant. From 1997 until March 2001, Mr. Hansen was employed as Operations Manager of the Gulf Coast Division for Basin Exploration, Inc. From 1991 to 1997, he was employed in various engineering positions at Greenhill Petroleum Corporation, including Senior Production Engineer and Workover/Completion Superintendent. Mr. Hansen started his career with Shell Oil Company in 1978 and has 27 years of experience in conducting operations in the oil and gas industry.

Cory L. Loegering Mr. Loegering was promoted to Senior Vice President Deepwater in September 2006 and served as Vice President Deepwater from August 2002 to September 2006. Mr. Loegering joined Mariner in July 1990 and since 1998 has held various positions including Vice President of Petroleum Engineering and Director of Deepwater development. Mr. Loegering was employed by Tenneco from 1982 to 1989, in various positions including as senior engineer in the economic, planning and analysis group in Tenneco s corporate offices. Mr. Loegering began his career with Conoco in 1977 and held positions in the construction, production and reservoir departments responsible for Gulf of Mexico production and development. Mr. Loegering has 29 years of experience in the industry.

Richard A. Molohon Mr. Molohon was appointed Vice President Reservoir Engineering in May 2006. He joined Mariner in January 1995 as a Senior Reservoir Engineer and since then has held various positions in reservoir engineering, economics, acquisitions and dispositions, exploration, development, and planning and basin analysis, including Senior Staff Engineer from January 2000 to January 2004, and Manager, Reserves and Economics from January 2004 to May 2006. Mr. Molohon has more than 29 years of industry experience. He began his career with Amoco Production Company as a Production Engineer from 1977 until 1980. From 1980 to 1991, he was a Project Petroleum Engineer for various subsidiaries of Tenneco, Inc. From 1991 to 1995 he was a Senior Acquisition Engineer for General Atlantic Inc. Mr. Molohon has been a Registered Professional Engineer in Texas since 1983 and is a member of the Society of Petroleum Engineers.

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

Alan R. Crain, Jr. Mr. Crain was elected a director in April 2006. He is Vice President and General Counsel of Baker Hughes Incorporated and has served in that capacity since October 2000. He was Executive Vice President, General Counsel and Secretary of Crown, Cork & Seal Company, Inc. from 1999 to 2000. He was Vice President and General Counsel from 1996 to 1999, and Assistant General Counsel from 1988 to 1996, of Union Texas Petroleum Holdings, Inc.

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

John F. Greene Mr. Greene was elected as a director in August 2005. He served as Executive Vice President of Worldwide Exploration, Production and Natural Gas Marketing at Louisiana Land & Exploration Company before his retirement in 1995. Prior to joining Louisiana Land & Exploration Company, Mr. Greene was the President and Chief Executive Officer of Milestone Petroleum, Inc. (today, Burlington Resources, Inc.) from 1981 to 1985. Mr. Greene served on the board of directors of Colorado-Wyoming Reserves Company from 1998 through 2004 and as a director and member of the compensation committee of Basin Exploration, Inc. from 1996 through 2001. Mr. Greene began his career at Conoco and served in the United States Navy from 1963 until 1968. He is currently a partner and director of The Shoreline Company and Leaf River Resources.

H. Clayton Peterson Mr. Peterson was elected a director in March 2006. During his 33-year career with Arthur Andersen, he specialized in audits of oil and gas companies. Most recently, from January 2000 to September 2002, Mr. Peterson was Managing Partner of the Denver office of Arthur Andersen and Regional Managing Partner of the audit practices of Arthur Andersen in Tulsa, Oklahoma City and Dallas. Since September 2002, Mr. Peterson has been a business consultant, including to the Estate of Kim Magness from August 2003 to present. He has been a member of the board of directors of RE/MAX International, Inc. since May 2005 and is co-chair of its audit committee.

John L. Schwager Mr. Schwager was elected as a director in August 2005. Prior to his retirement in 2004, Mr. Schwager served as Chief Executive Officer and President of Belden & Blake Corporation. Before joining Belden & Blake Corporation in 1999, Mr. Schwager was the founder and served as President of AnnaCarol Enterprises, Inc., a consulting firm that provided planning, advisory, evaluation and management services to the energy industry. From 1984 until 1997 he served in several management roles, including President and Chief Executive Officer at Alamco, Inc. From 1970 through 1984, Mr. Schwager held various engineering, operations, management and executive officer positions with Callon Petroleum Company and Shell Oil Company.

Board of Directors

Under the terms of the Forest Energy Resources merger agreement, as amended, the Board of Directors of Mariner after completion of the merger is to be composed initially of seven individuals, five of whom were directors of Mariner immediately prior to the merger, one of whom, Mr. Peterson, was mutually agreed upon by Mariner and Forest prior to, and became a director upon, completion of the merger, and one of whom, Mr. Crain, was mutually agreed upon by Mariner and Forest for appointment on April 1, 2006.

Our certificate of incorporation and bylaws provide for a classified board of directors consisting of three classes of directors, each serving staggered three-year terms. As a result, stockholders will elect a portion of our Board of Directors each year. The Class I directors term will expire at the annual meeting of stockholders to be held in 2009, Class II directors terms will expire at the annual meeting of stockholders to be held in 2007 and Class III directors terms will expire at the annual meeting of stockholders to be held in 2008. Currently, the Class I directors are Messrs. Aronson, Crain and Peterson, the Class II directors are Messrs. Greene and Schwager, and the Class III directors are Messrs. Ginns and Josey. Effective upon completion of the merger, the directors increased the board to six and elected Mr. Peterson to fill the vacancy. On April 1, 2006, the directors increased the board to seven and elected Mr. Crain to fill the vacancy. Pursuant to provisions in our certificate of incorporation regarding vacancies on the Board of Directors, Messrs. Peterson and Crain must stand for reelection at the next annual stockholders meeting for a term expiring at the 2009 annual stockholders meeting. At each annual meeting of stockholders held after the initial classification, the successors to directors whose terms will then expire will be elected to serve from the time of election until the third annual meeting following election. The division of our Board of Directors into three classes with staggered terms may delay or prevent a change of our management or a change in control.

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

Committees of the Board

Our Board of Directors has established four committees, the audit committee, the compensation committee, the nominating and corporate governance committee, and the executive committee.

Each of Messrs. Aronson, Ginns and Peterson (Chairman) is a member of our audit committee and is independent under the listing standards of New York Stock Exchange and SEC rules. In addition, the Board of Directors has determined that Mr. Peterson is an audit committee financial expert, as defined under the rules of the SEC. The audit committee recommends to the Board of Directors the independent public accountants to audit our financial statements and oversees the annual audit. The committee also approves any other services provided by public accounting firms. The audit committee provides assistance to the Board of Directors in fulfilling its oversight responsibility to the stockholders, the investment community and others relating to the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent auditor s qualifications and independence, and the performance of our internal audit function. The committee oversees our system of disclosure controls and procedures and system of internal controls regarding financial, accounting, legal compliance and ethics that management and the Board of Directors have established. In doing so, it is the responsibility of the committee to maintain free and open communication between the committee and our independent auditors, the internal accounting function and management of Mariner.

Each of Messrs. Aronson (Chairman), Crain and Greene serves on the nominating and corporate governance committee of our Board of Directors and is independent under the listing standards of the

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New York Stock Exchange and SEC rules. This committee nominates candidates to serve on our Board of Directors and approves director compensation. The committee also is responsible for monitoring a process to assess board effectiveness, developing and implementing our corporate governance guidelines and in taking a leadership role in shaping the corporate governance of Mariner.

Each of Messrs. Ginns, Greene and Schwager (Chairman) serves on the compensation committee of our Board of Directors and is independent under the listing standards of the New York Stock Exchange and SEC rules. The compensation committee reviews the compensation and benefits of our executive officers, establishes and reviews general policies related to our compensation and benefits, and administers our Equity Participation Plan and Amended and Restated Stock Incentive Plan. Under the compensation committee charter, the compensation committee determines the compensation of our CEO.

Each of Messrs. Ginns, Josey (Chairman), Peterson and Schwager serves on the executive committee of our Board of Directors. The executive committee may exercise the powers and authority of the Board in managing the business and affairs of the Company when the Board is not in session, subject to our certificate of incorporation, applicable law and any limits on authority determined from time to time by the Board.

Director Compensation

Officers and employees who also serve as directors will not receive additional compensation. For periods before August 11, 2005, Messrs. Aronson and Ginns did not receive compensation for their services as directors. For director services from August 11, 2005 through March 1, 2006, the Company paid cash compensation on an annual basis of $40,000 to each of Messrs. Aronson, Ginns, Greene and Schwager. In addition, on March 31, 2006, the Company granted each of them 1,100 shares of restricted stock under the Company s Amended and Restated Stock Incentive Plan, as amended, with one-third of the shares to vest upon each of the first three annual meetings of Mariner s stockholders following the date of grant. The 1,100 shares of restricted stock granted to each of Messrs. Greene and Schwager replaced an option each received upon his appointment to the Board in August 2005, exercisable for 4,500 shares of the Company s common stock at $15.50 per share, and vesting in 1/3 increments upon each of the three successive annual meetings of Mariner s stockholders following the date of grant. As of March 31, 2006, neither of these in the money options had been exercised.

Effective March 2, 2006, non-employee directors will receive annual compensation for service as a director of $50,000, and additional annual compensation of $12,500 for serving on the board s audit committee, $20,000 for serving as chairman of the audit committee, $5,000 for serving on any board committee other than the audit committee, and $10,000 for serving as chairman of any board committee other than the audit committee. Non-employee directors also will be paid a meeting fee of $1,500 for attendance or participation by phone at board meetings and $1,000 for attendance or participation by phone at board committee meetings. All nonemployee director fees will be paid quarterly. In addition, each director will be reimbursed for out-of-pocket expenses in connection with attending meetings of the Board of Directors or committees. Each director will be fully indemnified by us for actions associated with being a director to the extent permitted under Delaware law.

The Board of Directors authorized a restricted stock grant made on March 31, 2006 to each nonemployee director and on April 3, 2006 to Mr. Crain equal to that number of shares of Mariner s common stock with a market value, determined as of the date of grant, of $50,000, with one-third of the shares to vest on each of the first three annual meetings of Mariner s stockholders following the date of grant. Each grant of 2,438 shares on March 31, 2006, based on the closing price of $20.51 per share, and of 2,465 shares on April 3, 2006, based on a closing price of $20.28 per share, was made under Mariner s Amended and Restated Stock Incentive Plan, as amended.

Indemnification

We maintain directors and officers liability insurance. Our certificate of incorporation and bylaws include provisions limiting the liability of directors and officers and indemnifying them under certain circumstances. We have also entered into indemnification agreements with our executive officers and directors

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providing our executive officers and directors with additional assurances in a manner consistent with Delaware law.

Executive Compensation

The following table shows the annual compensation for our chief executive officer and the five other most highly compensated executive officers for the three fiscal years ended December 31, 2005.

Summary Compensation Table

		Annual Compensation		Long-Term Compensation Awards			
Name and Principal Position	**Year**	**Salary ($)**	**Bonuses($)**	**Restricted Stock Awards ($)(2)**	**Securities Underlying Options (#)**	**Payouts LTIP Payouts ($)**	**All Other Compensation ($)(3)**
Scott D. Josey	2005	$ 375,000	$ 1,200,000	$		$	$ 16,210
Chairman of the Board,	2004	350,000	550,000	9,522,534	200,000	575,000	15,133
Chief Executive Officer	2003	300,290	850,000				514,895
and President							
Dalton F. Polasek	2005	250,000	580,000				16,626
Chief Operating Officer	2004	215,000	300,000	4,316,886	102,000	248,400	15,236
	2003	176,698	325,000				280,677
Mike C. van den Bold	2005	200,000	440,000				15,819
Senior Vice President and	2004	192,500	215,000	3,174,178	74,000	322,000	14,949
Chief Exploration Officer(1)	2003	170,150	350,000				45,430
Judd A. Hansen	2005	187,500	325,000				15,983
Senior Vice President	2004	180,000	185,000	2,221,926	48,000	184,000	15,059
Shelf and Offshore(1)							
	2003	156,023	250,000				109,272
Rick G. Lester(2)	2005	200,000	300,000				16,363
Vice President,	2004	43,352	120,000	428,512	40,000		3,502
Chief Financial Officer and	2003						
Treasurer							
Teresa G. Bushman	2005	200,000	300,000				17,197
Senior Vice President, General	2004	190,000	215,000	1,920,380	40,000	59,800	14,834
Counsel and Secretary(1)	2003	97,750	200,000				23,270

(1) Mr. van den Bold was Vice President and Chief Exploration Officer in 2005 and until promoted to indicated position as of April 27, 2006. Mr. Hansen was Vice President Shelf and Offshore in 2005 and until promoted to indicated position as of April 27, 2006. Ms. Bushman was Vice President, General Counsel and Secretary in 2005 and until promoted to indicated position as of April 27, 2006.

(2) On October 16, 2006, Mr. Lester resigned as Vice President, Chief Financial Officer and Treasurer and John H. Karnes was appointed Senior Vice President, Chief Financial Officer and Treasurer. See Employment Agreements and Other Arrangements.

(3) Dollar amounts are calculated by multiplying the number of shares of common stock awarded by $14, the trading price of our common stock on the business day immediately preceding the date the award was granted. The restricted stock fully vested on May 31, 2006. For additional information regarding these grants, please see Equity Participation Plan.

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At December 31, 2005, the value of all restricted stock held by each named executive (based on the $17.75 trading price of our common stock on December 31, 2005) was as follows:

Name	No. of Shares	Value
Scott D. Josey	680,181	$ 12,073,213
Dalton F. Polasek	308,349	5,473,195
Mike C. van den Bold	226,727	4,024,404
Judd A. Hansen	158,709	2,817,085
Rick G. Lester	30,608	543,292
Teresa G. Bushman	137,170	2,434,768

(4) Amounts shown reflect insurance premiums paid by us with respect to term life insurance for the benefit of the named executive officers and retention payments paid during the year. The amounts for 2005 for Messrs. Josey, Polasek, van den Bold, Hansen and Lester and Ms. Bushman include $7,000 of employer matching contributions made pursuant to our 401(k) plan and $8,400 made pursuant to the profit sharing portion of our 401(k) plan. In addition, the 2005 amount includes insurance premiums under our group term life insurance of $810 for Mr. Josey, $1,226 for Mr. Polasek, $419 for Mr. van den Bold, $583 for Mr. Hansen, $963 for Mr. Lester, and $1,797 for Ms. Bushman.

Employment Agreements and Other Arrangements

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

Under the employment agreements, officers are entitled to the following severance benefits in the event of an officer s resignation for good reason, a termination by us without cause, upon disability or, in the case of Mr. Josey s agreement, our non-renewal of the agreement: (i) a lump sum payment equal to 2.0 (2.5 for Messrs. Polasek, van den Bold and Hansen, and Ms. Bushman, and 2.99 for Mr. Josey) times the sum of the officer s base salary and three year average annual bonus, (ii) health care coverage for a period of eighteen months (two years for Mr. Josey and Mr. Polasek), (iii) 100% vesting of all unvested restricted shares under our Equity Participation Plan (as discussed under Equity Participation Plan, all such shares have fully vested), and (iv) 50% vesting of all other unvested rights under any other equity plans, including our Amended and Restated Stock Incentive Plan. Subsequent awards under equity plans vest in accordance with their terms.

The employment agreements also provide for certain change of control benefits. Upon termination by us for any reason other than cause at any time within nine months after a change of control that occurs while the executive is employed, or upon the occurrence of a change of control within nine months following an officer s resignation of employment for good reason or termination by us without cause, the agreements provide for the following benefits: (i) a lump sum payment equal to 2.0 (2.5 for Messrs. Polasek, van den Bold and Hansen, and Ms. Bushman, and 2.99 for Mr. Josey) times the sum of the officer s base salary and three year average annual bonus, and (ii) 100% vesting of all unvested rights under any equity plans, including our Amended and Restated Stock Incentive Plan.

The executive officers of Mariner as of March 2, 2006 became entitled to receive cash payments of $1,000 each in exchange for the waiver of certain rights under their employment agreements, including the automatic vesting or acceleration of restricted stock and options upon the completion of the merger with Forest Energy Resources and the right to receive a lump sum cash payment if the officer voluntarily terminates employment without good reason within nine months following the completion of the merger.

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The employment agreements provide that the officers are entitled to a full tax gross-up payment if the aggregate payments and benefits to be provided constitute a parachute payment subject to a Federal excise tax. The agreements also include confidentiality and non-solicitation provisions.

The term of Mr. Lester s employment agreement expired upon his resignation as an employee effective August 15, 2006. He is leaving Mariner to pursue personal interests and served as an officer of Mariner until October 16, 2006 under a consulting agreement made effective August 16, 2006 while Mariner continued its search for his successor. Under the consulting agreement, Mr. Lester agreed to perform finance, accounting and other services on a consulting basis, continue to serve in his capacity as an officer of Mariner, and assist in transition upon the hiring of his successor. The consulting agreement, which we expect will terminate in December 2006, provides that Mariner pay Mr. Lester $2,300 per day for his services. In connection with Mr. Lester s resignation as an employee, Mariner agreed to pay him a bonus in the amount of $237,500 in respect of his performance in 2006 as an employee.

Mariner and John H. Karnes, who became its Senior Vice President, Chief Financial Officer and Treasurer in October 2006, entered into an employment agreement, dated as of October 16, 2006. The employment agreement has an initial term ending October 15, 2007 and automatically renews each October 15 thereafter for an additional 12 months unless prior notice is given. It provides for a base salary that may be adjusted annually in the sole discretion of Mariner s Board of Directors, a discretionary bonus, and participation in Mariner s benefit plans and programs. The initial base salary on an annualized basis is $235,000. If Mr. Karnes remains employed by Mariner until such time in 2007 as bonuses in respect of performance in 2006 are paid to other officers of Mariner, then for his services during 2006, Mariner will pay him a guaranteed bonus of not less than $125,000 and grant him no fewer than 20,000 shares of restricted common stock of Mariner, which is expected to have a four-year vesting schedule. In connection with Mariner s employment of Mr. Karnes, it granted him 15,000 shares of restricted common stock in October 2006 under its Amended and Restated Stock Incentive Plan, as amended, subject to four-year vesting.

Under the employment agreement, if Mr. Karnes terminates his employment for good reason or Mariner terminates his employment without cause, he is entitled to a severance payment of (i) $375,000 if the termination occurs before the earlier of April 16, 2007 or the occurrence of a change of control, or (ii) a lump sum payment equal to 2.99 times the sum of his base salary and three-year average annual bonus if the termination occurs on or after April 16, 2007 or the occurrence of a change of control. If Mariner terminates his employment due to disability, he is entitled to a lump sum payment equal to 2.99 times the sum of his base salary and three-year average annual bonus. Mr. Karnes also is entitled to the following severance benefits if he resigns for good reason or Mariner terminates his employment without cause or due to disability: (i) health care coverage for a period of 18 months, and (ii) 50% vesting of all unvested rights under any equity plans of Mariner. Subsequent awards under equity plans vest in accordance with their terms. In addition, upon the occurrence of a change of control that occurs during the period Mr. Karnes is employed or within nine months after he resigns for good reason or Mariner terminates his employment without cause, he will become 100% vested in all unvested rights under any of Mariner s stock and other equity plans.

The employment agreement provides that Mr. Karnes is entitled to a full tax gross-up payment if the aggregate payments and benefits to be provided constitute a parachute payment subject to a Federal excise tax. It also includes confidentiality and non-solicitation provisions.

Overriding Royalty Arrangements

Mariner s geologist and geophysicist employees are eligible to participate in Mariner s Amended and Restated Gulf of Mexico Overriding Royalty Interest Plan. Pursuant to the terms of the plan, overriding royalty interests (ORRIs) may be awarded to participants in the plan for prospects in the Gulf of Mexico that are generated or identified and acquired during the term of the participant s employment at Mariner. The maximum ORRI for all participants is 1.8% for shelf leases and 0.9% for deepwater leases, subject to proportionate reduction. The maximum ORRI per participant is 1/2 of one percent for shelf leases and 1/4 of one percent for deepwater leases, subject to proportionate reduction. Unless approved by Mariner s overriding royalty interest committee, no ORRIs are awarded for developed or undeveloped reserve acquisitions. Certain of the Forest Gulf of Mexico leases not covering developed or undeveloped reserves may become burdened by ORRIs under the plan as determined by such committee in accordance with the terms of the plan. None of the members of the committee is eligible to participate in the plan.

To avoid potential conflicts of interest, Mariner s geologist and geophysicist employees that participate in the Overriding Royalty Interest Plan (the ORRI Plan Participants) do not make decisions with respect to the pursuit of the acquisition, exploration or development of prospects. When an ORRI Plan Participant develops a lead for a prospect, executive management makes the decision whether to pursue to the acquisition, exploration or development of the prospect. In addition, ORRI Plan Participants are required at the time they become eligible for participation in the plan and periodically thereafter to disclose oil and gas properties in which they or their immediate family members have any interest and to abstain from participation in the evaluation of any property in which they or their immediate family members have any interest.

As of December 31, 2005, six employees participated in the plan. None of Mariner s officers or managers are eligible to participate in the plan. Since the inception of the plan in July 2002 through December 31, 2005, approximately $584,000 has been distributed to participants with respect to ORRIs granted to them under the plan, of which $332,000 was distributed in 2005.

In 2002, two of our current executive officers, Dalton F. Polasek, Chief Operating Officer, and Judd A. Hansen, Senior Vice President Shelf and Onshore, received assignments of ORRIs in certain leases acquired by us under a consulting arrangement. A consulting company owned in part by Mr. Polasek was assigned a 2% ORRI from us in four federal offshore leases as partial consideration for having brought the related prospect to us. With our knowledge and consent, the consulting company subsequently assigned portions of the ORRIs to Mr. Hansen and a company owned by Mr. Polasek. At the time of the assignments, Messrs. Polasek and Hansen served Mariner as officers and consultants but were not employed by Mariner. No payments were made in respect of these ORRIs until 2004, when each received less than $60,000 with respect to his ORRI. No payments were made in respect of these ORRIs in 2005.

We may have obligations under previously terminated employment and consulting agreements to assign additional ORRIs in some of our oil and natural gas prospects to current and former employees and consultants. Cory L. Loegering, Vice President Deepwater, and Richard A. Molohon, Vice President Reservoir Engineering, are the only current executive officers who may be entitled to receive ORRIs from time to time under any of these agreements. Mariner made net cash payments to each of Mr. Loegering of $378,312, $368,095 and $205,245 in 2005, 2004 and 2003, respectively, and Mr. Molohon of $282,153, $274,364 and $151,482 in 2005, 2004 and 2003, respectively in respect of ORRIs assigned from time to time pursuant to a right to receive such ORRIs that was granted in 2002.

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

Equity Participation Plan

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

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

The table below includes information regarding the restricted stock awards granted in March 2005 under the Equity Participation Plan to our chief executive officer, our five other most highly compensated executive officers as of the year ended 2005, and all officers as a group as of December 31, 2005.

Equity Participation Plan

Restricted Stock Awards

Officer or Group	No. of Shares	Value at Grant(1)
Scott D. Josey	680,181	$ 9,522,534
Dalton F. Polasek	308,349	4,316,886
Mike C. van den Bold	226,727	3,174,178
Judd A. Hansen	158,709	2,221,926
Rick G. Lester	30,608	428,512
Teresa G. Bushman	137,170	1,920,380
Officers as a group (8 persons)	1,803,614	25,250,596

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

In connection with the merger with Forest Energy Resources, all shares of restricted stock granted under the Equity Participation Plan vested as follows: (i) the 463,656 shares of restricted stock held by non-executive employees vested on March 2, 2006, and (ii) the 1,803,614 shares of restricted stock held by executive officers vested on May 31, 2006 pursuant to an agreement, made in exchange for a cash payment of $1,000 to each officer, that his or her shares of restricted stock would not vest before the later of March 11, 2006 or ninety days after the effective date of the merger. The Equity Participation Plan expired upon the vesting of all shares granted thereunder.

Stock could be withheld by us upon vesting to satisfy our tax withholding obligations with respect to the vesting of the restricted stock. Participants in the Equity Participation Plan had the right to elect to have us withhold and cancel shares of the restricted stock to satisfy withholding obligations. In such events, we would be required to pay any tax withholding obligation in cash. As a result of such participant elections, we withheld an aggregate 807,376 shares that otherwise would have remained outstanding upon vesting of the restricted stock, reducing the aggregate outstanding vested stock grants made under the Equity Participation Plan to 1,459,894 shares. The 807,376 shares withheld became treasury shares that were retired and restored to the status of authorized and unissued shares of common stock. We paid the associated withholding taxes in cash.

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

Amended and Restated Stock Incentive Plan

We adopted a Stock Incentive Plan which became effective March 11, 2005 and was amended and restated on March 2, 2006. The objectives of the Amended and Restated Stock Incentive Plan are to encourage employees and directors to acquire or increase their equity interest with Mariner and to provide a means whereby they may develop a sense of proprietorship and personal involvement in the development and financial success of Mariner. The Amended and Restated Stock Incentive Plan is also designed to enhance Mariner s ability to attract and retain the services of individuals who are essential for the growth and profitability of Mariner.

Awards to participants under the Amended and Restated Stock Incentive Plan may be made in the form of incentive stock options, or ISOs, non-qualified stock options or restricted stock. The participants to whom awards are granted, the type or types of awards granted to a participant, the number of shares covered by each award, the purchase price, conditions and other terms of each award are determined by the Board of Directors or the committee appointed by the Board of Directors to administer the Amended and Restated Stock Incentive Plan (the Committee).

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Shares Subject to the Amended and Restated Stock Incentive Plan

A total of 6.5 million shares of Mariner s common stock is subject to the Amended and Restated Stock Incentive Plan. No more than 2.85 million shares issuable upon exercise of options or as restricted stock can be issued to any individual. As of September 30, 2006, 4,966,071 shares remained available under the Amended and Restated Stock Incentive Plan for future issuance to participants.

Administration and Eligibility

The Committee has the authority to administer the Amended and Restated Stock Incentive Plan and to take all actions that are specifically contemplated by the Amended and Restated Stock Incentive Plan or are necessary or appropriate in connection with the administration of the Amended and Restated Stock Incentive Plan. The Committee has the full power and authority to designate participants, determine the type or types of awards, the number of shares to be covered by awards, and the terms and conditions of any award. The Committee also determines whether, to what extent, and under what circumstances awards may be settled or exercised in cash, shares or other securities, other awards or other property, or canceled, forfeited or suspended and the method or methods by which awards may be settled, exercised, canceled, forfeited or suspended. The Committee has the authority to establish, amend, suspend or waive such rules and regulations, and appoint such agents as it shall deem appropriate, and make any other determination or take any other action the Committee deems necessary for the proper administration of the Amended and Restated Stock Incentive Plan.

Any employee of Mariner (or any parent entity or subsidiary) and any non-employee director of Mariner is eligible to be designated a participant by the Committee. As of December 31, 2005, two non-employee directors and 51 employees had been granted awards under the Amended and Restated Stock Incentive Plan.

Awards

Awards may, in the discretion of the Committee, be granted either alone or in addition to, or in tandem with, any other award granted under the Amended and Restated Stock Incentive Plan or any award granted under any other plan of Mariner or any parent entity or subsidiary. Awards granted in addition to or in tandem with other awards or awards granted under any other plan of Mariner or any parent entity or subsidiary may be granted either at the same time as or at a different time from the grant of such other awards. All or part of an award may be subject to conditions established by the Committee.

The types of awards to participants that may be made under the Amended and Restated Stock Incentive Plan are as follows:

Options. Options are rights to purchase a specified number of shares of common stock at a specified price. The Committee will determine the participants to whom options are granted, the number of shares to be covered by each option, the purchase price and the conditions, which of the options is an ISO or a nonqualified stock option, and limitations applicable to the exercise of the option. To the extent that the aggregate fair market value, determined at the time the respective ISO is granted, of common stock with respect to which ISOs are exercisable for the first time by an individual during any calendar year under all incentive stock option plans of Mariner and its parent and subsidiary corporations exceeds $100,000, or such option fails to constitute an ISO for any reason, such purported ISOs will be treated as non-qualified stock options.

ISOs may be granted only to an individual who is an employee of Mariner or any parent or subsidiary corporation at the time the option is granted. The Committee determines the exercise price at the time each option is granted, but the exercise price shall never be less than the fair market value per share on the effective date of such grant. The

Committee determines the time or times at which each option may be exercised, the method or methods by which, and the form or forms in which, payment of the exercise price may be made or deemed to have been made.

An ISO must be granted within 10 years from the date the Amended and Restated Stock Incentive Plan was approved by the Board or the shareholders, whichever is earlier. No ISO shall be granted to an individual if, at the time the ISO is granted, such individual owns stock possessing more than 10% of the total combined voting power of all classes of stock of Mariner or of its parent or subsidiary corporation, unless:

at the time the ISO is granted, the option price is at least 110% of the fair market value of the common stock subject to the option; and

such ISO, by its terms, is not exercisable after the expiration of five years from the date of grant.

Options are not transferable, other than by will or the laws of descent and distribution, and are exercisable during the participant s lifetime only by the participant or the participant s guardian or legal representative.

Restricted Stock. Restricted stock is stock that has limitations placed on it. Dividends paid on restricted stock may be paid directly to the participant, sequestered and held in a bookkeeping account, or reinvested in additional shares, which may be subject to the same restrictions as the underlying award or other restrictions, as determined by the Committee. Restricted stock is evidenced in such manner as deemed appropriate by the Committee, but any stock certificate that is issued in respect of restricted stock granted under the Amended and Restated Stock Incentive Plan must be registered under the participant s name and bear an appropriate legend referring to the terms, conditions and restrictions applicable to the restricted stock.

Unless otherwise determined by the Committee or provided in an award agreement, upon termination of a participant s employment for any reason during the applicable restricted period, which is the period established by the Committee with respect to an award during which the award either remains subject to forfeiture or is not transferable by the participant, all restricted stock is forfeited without payment and reacquired by Mariner. The Committee may waive in whole or in part any or all remaining restrictions on such participant s restricted stock, but if such award was intended to qualify as performance-based compensation, then only upon an event permitted under Section 162(m) of the Code. Restricted stock is subject to such limitations on transfer as are necessary to comply with Section 83 of the Code.

Other Provisions

Unless sooner terminated, no award may be granted under the Amended and Restated Stock Incentive Plan after October 12, 2015. The Board of Directors or the Committee may amend, alter, suspend, discontinue or terminate the Stock Incentive Plan without the consent of any stockholder, participant, other holder or beneficiary of an award or any other person. However, no amendment may materially adversely affect the rights of a participant under an award without the consent of such participant.

In the event of any distribution, recapitalization, reorganization, merger, spin-off, split-off, split-up, consolidation, combination, repurchase, or exchange of shares or other securities of Mariner or any other relevant corporate transaction or event or any unusual or nonrecurring transactions or events affecting Mariner, the Committee may, in its sole discretion and on such terms and conditions as it deems appropriate:

provide for either the termination of any such award in exchange for cash in the amount that would have been attained upon the exercise of such award or the replacement of such award with other rights or property selected by the Committee;

provide that such award be assumed by the successor or survivor corporation or its parent or be substituted for by similar options, rights or awards; or

make adjustments in the number and type of shares or other property subject to outstanding awards.

Amended and Restated Stock Incentive Plan Benefits

Because the granting of awards under the Amended and Restated Stock Incentive Plan is at the discretion of the Committee, it is not now possible to determine which persons may be granted awards. Also, it is not now possible to estimate the number of shares of common stock that may be awarded under the Amended and Restated Stock Incentive Plan.

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U.S. Federal Tax Consequences

The following is a general discussion of the current Federal income tax consequences of awards under the Amended and Restated Stock Incentive Plan to participants who are classified as U.S. residents for Federal income tax purposes. Different or additional rules may apply to participants who are subject to income tax in a foreign jurisdiction and/or are subject to state or local income tax in the United States. Each participant should rely on his or her own tax advisors regarding federal income tax treatment under the Amended and Restated Stock Incentive Plan.

Restricted Stock

The grant of restricted stock does not result in taxable income to the participant. At each vesting event, the participant will recognize taxable ordinary income equal to the excess of the fair market value of the shares of common stock that become vested over the purchase price (if any) paid for such common stock. However, if a participant makes a timely election under Section 83(b) of the Code, the participant will recognize taxable ordinary income in the taxable year of the grant equal to the excess of the fair market value of the shares of common stock underlying the restricted stock award at the time of the grant over the purchase price (if any) paid for such common stock. Furthermore, the participant will not recognize ordinary income on such restricted stock when it subsequently vests.

In all cases, the participant s ordinary income is subject to applicable withholding taxes. Mariner will be allowed an income tax deduction in the taxable year the participant recognizes ordinary income, in an amount equal to such ordinary income.

Stock Options

The grant of a non-qualified stock option will not result in taxable income to the participant and Mariner will not be entitled to an income tax deduction. Upon the exercise of a non-qualified stock option, a participant will realize ordinary taxable income on the date of exercise. Such taxable income will equal the difference between the fair market value of the common stock on the date of exercise and the option price. Mariner will be entitled to an income tax deduction equal to the amount included in the participant s ordinary income.

Upon the grant or exercise of an ISO, a participant will not recognize taxable income and Mariner will not be entitled to an income tax deduction. However, the exercise of an ISO will result in an amount being included in the participant s alternative minimum taxable income for the year in which the exercise occurs equal to the excess of the fair market value of the common stock purchased under the ISO at the time of exercise over the option price.

The optionee will recognize taxable income in the year in which the shares of common stock underlying the ISO are sold or disposed of. Dispositions are divided into two categories: qualifying and disqualifying. A qualifying disposition occurs if the sale or disposition is made more than two years from the option grant date and more than one year from the exercise date. If the participant sells or disposes of the shares of common stock in a qualifying disposition, any gain recognized by the participant on such sale or disposition will be a long-term capital gain.

If either of the two holding periods described above are not satisfied, then a disqualifying disposition will occur. If the optionee makes a disqualifying disposition of the shares of common stock that have been acquired through the exercise of the option, then the optionee will have ordinary taxable income for the taxable year in which the sale or disposition occurs equal to the lesser of:

- the excess of the fair market value of such shares on the option exercise date over the exercise price paid for the shares; or the amount realized on the sale or disposition over the exercise price paid for the shares.

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If the optionee makes a qualifying disposition, Mariner will not be entitled to an income tax deduction. However, if the optionee makes a disqualifying disposition, Mariner will be entitled to an income tax deduction equal to the amount included in ordinary income to the participant.

The table below includes information regarding stock options under the Amended and Restated Stock Incentive Plan granted in our last fiscal year to our chief executive officer and our five other most highly compensated executive officers.

Option Grants in Last Fiscal Year

Name	No. of Securities Underlying Options	% of Total Options Granted to Employees in Fiscal Year	Exercise Price	Expiration Date	Potential Realizable Value of Assumed Annual Rates of Stock Price Appreciation for Option Term(1) 5%($)	10%($)
Scott D. Josey	200,000	24.7%	$ 14.00	3/11/2015	$ 1,760,905	$ 4,462,479
Dalton F. Polasek	102,000	12.6	14.00	3/11/2015	898,062	2,275,864
Mike C. van den Bold	74,000	9.1	14.00	3/11/2015	651,535	1,651,117
Judd A. Hansen	48,000	5.9	14.00	3/11/2015	422,617	1,070,995
Rick G. Lester	40,000(2)	4.9	14.00	3/11/2015	352,181	892,496
Teresa G. Bushman	40,000	4.9	14.00	3/11/2015	352,181	892,496

(1) In accordance with SEC rules, these columns show gain that could accrue for the listed options, assuming that the market price per share of our common stock appreciates from the date of grant over a period of 10 years at an annualized rate of 5% and 10%, respectively. If the stock price does not increase above the exercise price at the time of exercise, the realized value from these options will be zero.

(2) This option expired unexercised on August 15, 2006.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information as of November 3, 2006 (except as otherwise indicated) with respect to the beneficial ownership of Mariner s common stock by (i) 5% stockholders, (ii) current directors, (iii) six most highly compensated executive officers during 2005 and (iv) current executive officers and directors as a group.

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